Australian Energy Market Commission

RULE

## RULE DETERMINATION

# NATIONAL ELECTRICITY AMENDMENT (TRANSMISSION LOSS FACTORS) RULE 2020

**PROPONENT**

Adani Renewables

27 FEBRUARY 2020

## INQUIRIES

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## ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

# SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has made a more preferable rule to provide the Australian Energy Market Operator (AEMO) with greater flexibility to refine and improve the methodology to determine marginal loss factors (MLF).

2 This final rule complements the recent changes the Commission has made to the National Electricity Rules (NER) on improving the transparency of new generation projects.[1] It also supports AEMO's work to improve the transparency and predictability of loss factors. Together, these changes are in the long term interest of consumers as they will enable better, more informed decision-making for prospective investors of generation assets. Additionally, existing market participants will have greater transparency and information relevant to the operation of existing assets.

3 Some stakeholders have been concerned about recent volatility in transmission loss factors as this creates revenue variability, and have suggested that these changes have been difficult to forecast. While the Commission understands these concerns, it also recognises the importance of maintaining clear signals for efficient dispatch and future investment in the market, even in times of change. Dampening such signals may result in consumers having to shoulder such uncertainties when they have no ability to manage or offset them. It is important to note that the recent volatility in transmission loss factors reflects the reality of the underlying network flows occurring in the system. It is fundamental to the efficient operation of the wholesale market, that prices and financial incentives are linked as closely as reasonably practicable to the physical operation of the network.

4 For these reasons, the more preferable rule retains the existing marginal approach to determining transmission loss factors, whilst providing AEMO additional flexibility to refine and improve its current methodology for calculating MLFs. The Commission is satisfied that the more preferable rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO). In the absence of a full dynamic, locational approach, continuing to calculate loss factors on an annual, forward-looking basis remains the most appropriate approach given the existing broader market design of the national electricity market (NEM). This is because a marginal loss factor methodology remains the most efficient way of accounting for physical transmission losses in the NEM, and accordingly, is the most appropriate method to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity. [2]

5 The recent volatility of loss factors experienced by some stakeholders arises from the market-wide transition that is currently underway. Traditional thermal plants are closing, and more renewable and asynchronous generators are connecting to the market — often in locations remote from load centres that may be serviced by relatively weak transmission lines.

6 Enabling this market transition to occur smoothly will require significant reforms to the

1 The final rule determination for Transparency of new projects can be found through this link: https://www.aemc.gov.au/rule-changes/transparency-new-projects

2 Under Section 7 of the National Electricity Law (NEL) which sets out the NEO.

market design of the NEM to make long term, robust improvements to the way operational decisions are made and investment is carried out for the long term benefit of consumers. Such changes are being progressed through a range of actions, including:

- the Commission's Coordination of generation and transmission investment (COGATI) review, which includes consideration of the appropriate long-term approach to losses
- the Energy Security Board's work to action the Integrated System Plan, which will govern future transmission planning and investment processes
- the Energy Security Board's development of a post-2025 market design for the NEM.

## The rule change requests and Commission's response

7 The Commission has considered two rule change requests submitted by Adani Renewables. The first of these proposed that the intra-regional settlement residue (IRSR) should be shared equally between transmission customers and generators. The second sought to change the marginal loss factor methodology to an average loss factor methodology.

8 The Commission consolidated these two rule change requests under s. 93 of the NEL to enable it to address the overlapping issues arising from these requests.

9 In regard to the allocation of the intra-regional settlement residue (IRSR), the Commission has decided not to make a final rule in the manner proposed by Adani Renewables. The IRSR arises as the use of marginal loss factors generally tends to result in an over-recovery of funds from settlement. This is currently allocated to transmission customers through reduced transmission use of system (TUOS) charges.

10 Redistributing part of the IRSR to generators would be likely to result in generation asset owners taking into account the anticipated effect of the IRSR in their bidding decisions. This may impact the order of dispatch of generation units in the NEM, resulting in less efficient operation of the market. Taking into account the potential IRSR may also dampen the locational signals that marginal loss factors provide to prospective investors in new generation assets. This may also lead to less efficient investment over the long term.

11 In its rule change request, Adani Renewables suggested that redistributing the IRSR would result in lower electricity prices to customers. However, it is unlikely that any such reductions would fully offset the increased TUOS charges that would also occur under this approach. The current arrangements directly pass the benefits of the IRSR to consumers. As consumers pay for transmission infrastructure, it is appropriate that their transmission costs are reduced.

12 For these reasons, the Commission is not satisfied that the proposed change to reallocate half the IRSR to generators would, or would be likely to, contribute to the achievement of the NEO.

13 In regard to the second rule change request, the Commission has concluded that the use of average loss factors would be unlikely to better contribute to the achievement of the NEO than the final rule (which retains the current marginal loss factor methodology). The Commission undertook additional quantitative analysis to further evaluate the effects of moving from a marginal loss factor methodology to an average loss factor methodology. The

Commission's additional quantitative analysis confirmed that the final rule (which retains a marginal loss factor framework) will, or is likely to, better contribute to the achievement of the NEO than an average loss factor framework as proposed by Adani Renewables.

14 In addition to the Commissions quantitative analysis there are a number of reasons for this conclusion:

- The current marginal loss factor methodology provides important locational signals for prospective investors and owners of new generation assets which are needed to enable efficient decision-making about investment in the generation sector. This is particularly important in the current transformation of the electricity market.
- While an average loss factor method to determining transmission loss factors may result in a reduction in the volatility of loss factor values, it would also dampen locational signals for new efficient generation investment needed for the future. This is undesirable in the current climate where it is important that a variety of type and size of generation assets are introduced across various locations in the market. Using an average loss factor methodology may also lead to more generation investment in inefficient locations, increasing physical transmission losses further. This would in turn require a greater amount of electricity to be generated which, in the long-run, would be likely to lead to higher electricity costs for consumers.
- The use of average loss factors to address concerns from some investors about recent revenue volatility and increases in their cost of capital does not outweigh the likely reduction in efficient investment signals and dispatch decisions that would occur across the NEM or the impact on the affordability of electricity for consumers.
- Continuing to use a marginal loss factor methodology is consistent with the marginal approach currently used in the NEM for dispatch decision-making and pricing, supporting efficient market operations.
- The use of an average loss factor may change the dispatch order of generators, resulting in less efficient use of the generation fleet and reducing the efficient operation of the NEM in real time. This may have the effect of wholesale electricity prices being higher than they would otherwise be using marginal loss factors.

15 In addition, the Commission notes:

- The final rule retains the benefits of the marginal loss factor approach while providing AEMO, in consultation with market participants, a greater ability to improve the current calculation techniques within that framework without impacting on accuracy. This aims to enable AEMO to make refinements and improvements to the determination of marginal loss factors consistent with the long term interest of consumers.
- While the loss factor values for many generators have materially declined over the last two to three years, other generators have not had this experience. A move to average loss factors would benefit some generators more than others, and would result in some generators being worse off. This is particularly the case for embedded generators located near major load centres and some batteries. For example, the recent indicative loss factors for 2020-2021 published by AEMO in November 2019 show that loss factors are forecast to worsen for some generators, but are expected to improve for many

generators, with one of the largest improvements being for the Gannawarra Energy Storage System in Victoria, which has an indicative generation loss factor of greater than 1.0.

16 The Commission has also considered whether methodologies other than average or marginal approaches should be used to determine transmission loss factors. However, none of the approaches that have the potential to be implementable through this rule change process (cap and collar, grandfathering, or the compression model used in Ireland) are likely to better contribute to the achievement of the NEO than the current marginal approach. Similar to an average loss factor methodology, each of these approaches distort the investment location and operational dispatch signals provided by loss factors. As a result, they raise significant concerns for efficient investment in, and operation of, the NEM and are likely to transfer risks and costs either to other generators or to consumers.

17 Two other potential approaches to the treatment of transmission losses — recovering all costs from customers (as in the Italian market) and dynamic loss factors — were also suggested by stakeholders during this rule change process. In both cases, significant reforms to the operation of the NEM would be required if these approaches were to be implemented. While such changes are outside the scope of this rule change process, the consideration of a more market integrated loss factor approach is being undertaken through the Commission's COGATI review.[3]

## Final rule and current improvements

18 The final rule includes amendments to the NER to enable AEMO to refine and improve the marginal loss factor methodology. These amendments enable AEMO to consult with stakeholders on a greater range of alternative calculation details for the marginal loss factor methodology while maintaining accuracy and providing clear, efficient locational and dispatch signals to the market. Specifically, the final rule:

- removes the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- removes the requirement that marginal loss factor values must be based on a 30 minute interval to allow greater time periods to be used as the basis for calculating marginal loss factor values
- removes the principle at clause 3.6.2(e)(6) that requires flows in network elements that solely or principally provide market network services to be treated as invariant when calculating marginal losses.

19 The substantive changes under the final rule commence on 5 March 2020.

20 In addition to these changes, some improvement to the marginal loss factor methodology and information about loss factors are being made by AEMO without any amendments to the

3 To address the broader issues identified by the Commission and stakeholders would require broader market reform to areas such as but not limited to: transmission planning and the implementation of some form of dynamic pricing. This is beyond the scope of the consolidated rule change request.

NER. Specifically, AEMO has:

- introduced more frequent publication of marginal loss factor values for information and transparency purposes, with the first quarterly report released in November 2019
- undertaken to review the methodology through a consultation process with stakeholders to improve accuracy, efficiency and transparency of the MLF methodology following publication of the 2020-2021 MLF values in April 2020
- continued to improve generation investment information available on its generation information webpage, including information on transmission connection applications and enquiries.

21 The Commission and AEMO encourage stakeholders to engage in AEMO's consultation processes and assist with the development of these improvements that should result in a greater understanding and transparency of the methodology and the movement of the loss factor values over time.

22 These improvements will be complemented by additional information that will be available as a consequence of the Transparency of new projects rule change. This new rule, which fully took effect on 31 January 2020 and was published on 24 October 2019, will make more information about new generation projects more readily available, and provide for more regularly updated data on existing and proposed connections of generating plant to the national grid.

23 The Transparency of new projects rule is an important and practical amendment to the NER that will enable better informed investment decision-making to occur, reducing the likelihood of electricity users paying for inefficient investments. It will assist stakeholders in understanding the changing market and, in particular, the prospects for investing in the generation sector. In addition, it will enable existing owners of generation assets to be better informed about market developments and the impact this may have on their business.

## Longer term reform direction

24 The recent volatility in loss factors is symptomatic of broader issues being experienced in the NEM as a result of the transition underway in generation technologies, such as security output constraints, congestion risk and energy and emissions policy uncertainty. It is expected that new generation capacity totalling approximately the current size of the NEM (that is, 50 GW) will connect over the next 10 years. Most existing generation stock will be replaced by 2040.

25 Unlike the existing electricity system, the system of the future is likely to be characterised by numerous relatively small and geographically dispersed generation units with many located on the periphery of the NEM away from key demand centres to suit fuel sources such as solar or wind. However, the transmission system is typically relatively weak at these locations, and investment in transmission capacity (either under transmission network service provider (TNSP) regulated revenue or by other parties) has not kept up with the increased generation capacity installed at these particular locations. Despite the volatility of the marginal loss factor values, and some connection nodes experiencing declining marginal loss factors, there

has been a continued development of new generation assets in those same remote locations. This is exacerbating actual electrical losses on transmission lines and future volatility in marginal loss factors.

26 These issues are part of a broader set of generation and transmission coordination issues that the Commission is considering in detail in its COGATI review. Through the review, the Commission is developing a new access model, based around locational pricing (dynamic regional pricing) and financial transmission rights. Consideration of such longer term fundamental reforms are better considered as part of this review.

# CONTENTS

## APPENDICES



## TABLES

## FIGURES

# 1 INTRODUCTION

Adani Renewables submitted two rule change requests in relation to marginal loss factors (MLF) and the intra-regional settlement residue (IRSR). This chapter provides descriptions of these rule change requests which form this consolidated rule change process. It outlines the current arrangements in place for MLFs and IRSR as well as the steps carried out during this rule change process.

## 1.1 The rule change requests

Adani Renewables submitted a rule change request to the Commission on 27 November 2018 seeking to reallocate the IRSR to generators and "network users" equally. It stated that the purpose of this change would be:[4]

> an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

The IRSR for the national electricity market (NEM) region is currently distributed to the transmission network service provider (TNSP) for the region and is used to off-set transmission use of service (TUOS) charges paid by transmission customers.[5] TUOS charges ultimately flow through to the prices paid by end-users of electricity.

On 5 February 2019, Adani Renewables submitted a second rule change request. This request sought to change the MLF calculation methodology to an average loss factor methodology. Adani Renewables stated that the "current rules are resulting in high inaccuracies and hence, distort the market through inefficiencies in operational and investment decision making". In its view, changing to an average loss factor (ALF) approach would result in less losses for generators and a more accurate reflection of the cost of generation.[6] In its view, "MLF inaccuracies" result in IRSR accruing.

## 1.2 Current arrangements

When electricity is transported across a transmission network, some of it is lost as heat. Transmission loss factors are calculated to reflect this loss of electricity. Loss factors are used in the market settlement process so that generators are paid for the electricity received by users rather than the amount generated. Under the current arrangements, transmission losses in the NEM are calculated on a marginal basis.

MLFs represent the value of electrical energy that is lost when the next or marginal unit of electricity is transmitted across the transmission network. Specifically, an MLF value

4 Adani Renewables, rule change request, 27 November 2018, covering letter.

5 The term "transmission customer" is defined in Chapter 10 of the NER as a customer, non-register customer or distribution network service provider having a connection point with a transmission network.

6 Adani Renewables, rule change request, 5 February 2019, covering letter.

represents the losses for the marginal unit of electricity that occur between a generator or load connection point on the network and the regional reference node (RRN).

This "marginal" approach to calculating transmission losses is consistent with how other aspects of dispatch and pricing currently operate in the NEM. It has been used because marginal pricing leads to the most efficient outcomes when it is accurately applied.

Use of the marginal approach to transmission loss factors will, by design, over-recover total settlements used to pay generators. This over-recovery is the source of the IRSR.

The current approaches to determining both MLFs and the IRSR are set out below and in more detail in Appendix B of this final rule determination.

### 1.2.1 Calculating intra-regional loss factors

The requirements in relation to the calculation of intra-regional loss factors (that is, MLFs) for the NEM transmission networks are found in clauses 3.6.2 and 3.6.2A of the NER.

The NER specifies that AEMO must determine an intra-regional loss factor for each transmission connection point in accordance with its published methodology.[7]

In preparing its methodology as required by clause 3.6.2(d) of the NER, AEMO must implement a set of principles that can be summarised as follows:[8]

- the intra-regional loss factors are to apply for a financial year
- an intra-regional loss factor must, as closely as is reasonably practicable, describe the average of the marginal electrical energy losses for electricity transmitted between a transmission network connection point and the RRN in the same region for each trading interval of the financial year in which the intra-regional loss factor applies
- the intra-regional loss factors must aim to minimise the impact on the central dispatch process of generation and scheduled load compared to that which would result from a fully optimised dispatch process taking into account the effect of losses
- the intra-regional loss factors are determined using forecast load and generation data, as described in clause 3.6.2A of the NER
- the intra-regional loss factor for a transmission network connection point is determined using a volume weighted average of the marginal loss factors for the transmission network connection point for the financial year in which the intra-regional loss factor applies
- in determining an intra-regional loss factor for a transmission network connection point, flows in network elements that solely or principally provide market network services will be treated as invariant (that is, unchanged from the historical year, and not adjusted like generation).[9]

7 The loss factor methodology is available on the AEMO website.

8 Clause 3.6.2(e) of the NER.

9 The losses within market network services are treated separately.

Generally a single intra-regional loss factor is forecast and applies for each transmission connection point for a financial year.[10] AEMO must publish the intra-regional loss factors it determines by 1 April prior to the financial year in which they are to apply.[11]

While the current MLF methodology is consistent with the principles set out in the NER, it does include some features that enable the calculations to occur but also compromise its accuracy to some degree.[12] For example, the current approach relies on forecast information from parties such as the timing and quantity of generation that will be available. Nevertheless, the marginal approach is designed to achieve efficient dispatch and pricing of generation to meet demand across the NEM.

### 1.2.2 Calculating inter-regional loss factors

Related to intra-regional loss factors, or MLFs, are inter-regional loss factors.

Inter-regional loss factors describe the marginal electrical energy losses for electricity transmitted from the RRN in one region to the RRN in an adjacent region.[13] That is, these loss factors describe the losses arising from transporting electricity through a regulated interconnector.[14]

These loss factors are determined dynamically by loss factor equations in accordance with clauses 3.6.1 and 3.6.2A of the NER. AEMO is required under the NER to publish the inter-regional loss factor equations that describe the inter-regional electrical losses by 1 April prior to the financial year in which they are to apply.[15] This is to be carried out in accordance with the methodology prepared through a consultative process (that is, the Rules consultation procedures set out in rule 8.9 of the NER). In doing so, AEMO must implement a number of principles as set out in clause 3.6.1(d) of the NER, including that inter-regional loss factors:

- apply for a financial year and must be suitable for use in central dispatch for the NEM
- are calculated by inter-regional loss factor equations that "as closely as is reasonably practicable" describe the marginal electrical energy losses for electricity transmitted through a regulated interconnector between the two relevant RRNs and aim to minimise the impact on the central dispatch process of generation and scheduled load
- are calculated by using forecast load and generation data for the relevant financial year by applying regression analysis.

### 1.2.3 Settlement residue

The NER requirements on the settlements residue are set out in clause 3.6.5 of the NER. This clause provides a number of principles for AEMO to allocate, distribute or recover intra-

10 However, two intra-regional loss factors can be applied to a point under certain conditions. NER clause 3.6.2(b)(2)(i).

11 Clause 3.6.2(f1) of the NER.

12 Greater accuracy could be achieved by the use of a dynamic marginal approach to determining transmission losses.

13 Clause 3.6.1(b)(1) of the NER.

14 The regulated interconnectors in the NEM are currently Terranora, Queensland to New South Wales (QNI), Victoria to New South Wales (Vic1-NSW1), Heywood and Murraylink.

15 Clause 3.6.1(f) of the NER.

regional and inter-regional settlements residue. Of particular relevance to this rule change process, the principles include:[16]

- the distribution (or recovery) of settlements residue attributable to regulated interconnectors is to be carried out first in accordance with rule 3.18 of the NER
- the remaining settlements residue, including the portion due to intra-regional loss factors, is to be distributed to (or recovered from) the appropriate TNSP.

The IRSR is subsequently passed on to transmission customers through a reduction (or increase) in TUOS charges. Relevantly, clause 6A.23.3(e) of the NER states that the non-locational component of TNSP revenue is to be adjusted (either up or down) by the settlements residue due to intra-regional loss factors (that is, the IRSR). In addition, the prices for transmission customers to recover this non-locational component of revenue must be set on a postage stamp basis (clause 6A.23.4(e) of the NER). The use of a postage stamp approach to the distribution (or recovery) of IRSR means that transmission customers cannot influence the distribution of funds they received (or the recovery of funds they will pay).

## 1.3 Proposed solution and rationale

Adani Renewables sought to resolve the issues it perceived in relation to "inaccuracies" in the MLF values and the distribution of the IRSR to only customers via TNSPs by proposing that the NER be amended so that:

- transmission loss factors are calculated as average loss factors (rather than as marginal)
- the IRSR be shared equally between customers and generators.

Adani Renewables did not include aproposed rule drafting with its rule change requests with regard to either of these proposals. However, it identified that clause 6A.23.3 of the NER requires IRSR to be allocated between transmission customers based on their proportionate use of the relevant transmission assets. Adani Renwables' proposal implied a change to this provision would be necessary to achieve its objective.[17]

In regard to transmission loss factors, Adani Renewables suggested that "the inaccuracy in forecasting MLF for the following year/s results in generators assuming an artificially increased bid price as a result of an incorrect MLF".[18] This, in its view, subjects generators to increased risk of not being dispatched, resulting in increased cost of generation to all market customers.

To address these concerns, Adani Renewables proposed to move from the current forward-looking MLF methodology to an ALF methodology. It asserted that this change "from MLFs (with IRSR reallocation to include generators) to an ALF methodology will be a further improvement as average loss factors can be calculated at the commencement of each year (rather than a wash up of IRSRs in arrears)".[19]

16 Clause 3.6.5(a) of the NER.

17 Adani Renewables, rule change request, 27 November 2018, p. 9.

18 Adani Renewables, rule change request, 5 February 2019, covering letter.

19 Adani Renewables, rule change request, 5 February 2019, p. 3.

Adani Renewables' rationale for generators and transmission network customers to share the IRSR related to the issues that it identified with the current approach. Specifically:[20]

- that the calculations of loss factors give rise to approximations rather than actuals
- high IRSR reflects an "error" between actual and forecast transmission loss factors and consequently efficient dispatch is undermined and investment signals are impacted
- the allocation of residues on a postage stamp basis exacerbates the impact of inaccurate MLFs.

Adani Renewables stated that if a generator were to receive part of the IRSR as it had proposed, then that distribution of funds would result in "an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers".[21] Specifically, it stated that redistributing half of the IRSR funds to generators would:[22]

> correct for any inaccuracies associated with the MLFs, and associated inefficiencies caused by these inaccuracies. While this change to the reallocation process will not directly address the cause of inefficiencies caused by inaccurate MLFs, it may go some way to reducing the impacts this inaccuracy has on the investment and operational efficiency of the NEM.

In the rule change request, Adani Renewables stated that under the current framework a generator with an artificially low MLF as a result of forecast error, has its revenue and dispatch time reduced, and this works in opposition to micro economic competitive market fundamentals.[23] Adani Renewables summarised its proposed rule change by stating:[24]

> Adani Renewables proposes a rule change so that the process for the allocation of IRSRs be revised to include generation connection points and not only the network users who are subject to non-locational prescribed TUOS charges. The result of this rule change will be lower effective MLFs for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

## 1.4 The rule making process

The Commission consolidated the two rule change requests submitted by Adani Renewables under s. 93 of the NEL to enable it to address the overlapping issues arising from these requests within the one rule change process.

On 6 June 2019, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change requests.[25] A consultation

20 Adani Renewables, rule change request, 27 November 2018, p. 7.
21 Adani Renewables, rule change request, 27 November 2018, covering letter.
22 Adani Renewables, rule change request, 27 November 2018, pp. 7-8.
23 Adani Renewables, rule change request, 27 November 2018, p. 10.
24 Adani Renewables, rule change request, 27 November 2018, p. 3.
25 This notice was published under s. 95 of the NEL.

paper identifying specific issues for consultation was also published. Submissions closed on 18 July 2019.

The Commission received 35 submissions as part of the first round of consultation. A public workshop was hosted jointly with AEMO on 4 July 2019 in Brisbane and meetings with various stakeholders were also held. The issues raised by stakeholders during this consultation stage were considered by the Commission in making its draft rule determination. In addition, submissions were summarised and responded to in the draft rule determination and are also incorporated into this final rule determination.

On 26 September 2019, the Commission extended the period of time to make a draft rule determination until 21 November 2019. The Commission considered that this extension was necessary due to the complexity of issues arising from stakeholder submissions requiring further analysis. The Commission published the draft rule determination and draft rule on 14 November 2019.

The Commission subsequently received two requests to hold a pre-final rule determination hearing in relation to its draft rule determination. Accordingly, a hearing under s. 101 of the NEL was held on 4 December 2019 in Sydney. Representatives from six organisations presented their views to the Commission at the hearing.[26]

The Commission received 24 submissions in response to its draft rule determination and draft rule. The AEMC have also regularly met and engaged with stakeholders to understand and examine issues raised. The points raised in the submissions, as well as those raised at the hearing and in meetings, have been duly considered by the Commission in making this final rule determination and are addressed throughout this document.

26 A transcript of the hearing and other relevant documents are available from the AEMC website.

# 2 FINAL RULE DETERMINATION

This chapter sets out the Commission's final rule determination, the relevant decision-making framework and the reasons for its decision.

## 2.1 The Commission's final rule determination

The Commission's final rule determination is to make a more preferable rule. The more preferable rule makes limited changes to the MLF methodology principles.[27] These changes will provide AEMO with greater flexibility when updating and refining the MLF methodology and calculating MLFs. The final rule does not amend the NER in relation to the IRSR.

The Commission's reasons for making this final rule determination are summarised in section 2.5 below.

This chapter outlines:

- the rule making test for changes to the NER
- the more preferable rule test
- the assessment framework for considering the rule change request
- the Commission's consideration of the more preferable rule against the NEO.

Further information on the legal requirements for making this final rule determination is set out in Appendix A.

## 2.2 Rule making test

### 2.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.[28] The NEO is:[29]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

### 2.2.2 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

27 The more preferable rule also replaces the term "*transmission loss factors*" with "*intra-regional loss factors*" for consistency throughout the NER.

28 Section 88 of the NEL.

29 Section 7 of the NEL.

In this instance, the Commission has made a more preferable rule. The reasons are summarised below.

### 2.2.3 Rule making in relation to the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL.[30] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.[31]

Under the Northern Territory legislation adopting the NEL, the Commission may make a "differential rule" if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its terms as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems, but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s 91(8) of the NEL.

As the rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the rule against the additional elements required by the Northern Territory legislation.

## 2.3 Assessment framework

In assessing the rule change request against the NEO (that is, in accordance with section 91A of the NEL) the Commission has considered:

- The impact on efficient investment

  In the context of MLFs, achieving efficient investment requires the calculated MLF values to send efficient locational signals to potential investors in generation or load. This will occur where:

  - MLFs describe, as closely as reasonably practicable, the impact of electrical losses between the connection point and the regional reference node
  - MLFs, and changes to them, can be forecast as accurately as reasonably practicable by investors so that they can act on the locational signals provided.

  In assessing potential changes to the MLF framework, the Commission has considered whether the potential changes will improve the provision of information to enable stakeholders to make well-informed decisions on efficient investment in generation or load in the NEM. It has also considered the potential impact that loss factor values may

30 The regulations under the NT Act are the National Electricity (Northern Territory) (Uniform Legislation) (Modifications) Regulations.

31 The version of the NER that applies in the Northern Territory is available on the AEMC website.

have on market participant revenues and their cost of capital and the consequential impact that will have on the provision of electricity services to consumers.

- The impact on the efficient operation of providing electricity services

  MLFs influence generator bidding and plant operation, and therefore changes in how MLFs are determined can influence operational decisions by generators and dispatch decisions by AEMO.

  The Commission has considered whether changes to the transmission loss factor framework will support, and be consistent with, providing electricity services efficiently. This has included considering whether the suggested changes will enable more informed operational decisions to be taken by generators and other market participants and enable AEMO to dispatch the lowest cost generation, which should flow through to lower consumer prices.

- Risk allocation

  In general, it is desirable that the party that is allocated a risk has the incentive and ability to manage that risk because there is a clear link between that party's actions on the outcomes of the risk.

  In the case of MLFs, there is a risk to transmission connected market participants in regard to the value that will be calculated by AEMO at any time and that this value may change over time. However, these market participants may also be able to make decisions that impact on the value of the MLF allocated to them. For example, by decisions on where to locate a generator and how to allocate risk under their power purchase agreements. In contrast, consumers are not able to influence or manage the risks associated with MLFs.

  In considering whether the MLF framework should be changed, the Commission has considered the impact that the change may have on the allocation of risk between different market participants, and between market participants and consumers.

## 2.4 Overview of the final rule

### 2.4.1 Outline of the final rule

The more preferable rule made by the Commission is attached to and published with this final rule determination. The key features of the more preferable rule are:

- to remove the requirement in clause 3.6.1(d)(5) of the NER to use regression analysis to determine the equations in the MLF methodology
- to remove the requirement to base the MLFs on data from 30 minute trading intervals as set out in clause 3.6.2(e)(4) of the NER
- to remove the principle at clause 3.6.2(e)(6) that requires flows in network elements that solely or principally provide market network services to be treated as invariant when calculating marginal losses.

In addition to these amendments, the draft rule also replaces "transmission loss factors" with "intra-regional loss factors" in clauses 3.6.2(b), (g) and (h) and Chapter 10 (for the terms

"NMI Standing Data" and "virtual transmission node") of the NER. This was done to ensure consistency of terminology throughout the NER, without changing the meaning of those terms.

Further detail on the more preferable rule can be found in the following chapters of this final rule determination.

### 2.4.2 Changes from the draft rule

The final rule is largely the same as the draft rule. The only difference between the final rule and the draft rule is the deletion of clause 3.6.2(e)(6) of the NER. The draft rule amended this clause to clarify that AEMO's methodology is not required to calculate marginal losses within network elements that solely or principally provide market network services (in effect, removing the requirement that such calculations are to treat marginal losses within those elements as invariant). The Commission now considers that the clarification is unnecessary, and has effectively made that sub-clause unnecessary. Consequently, it has been deleted in the final rule.

These changes do not materially alter the intent or policy position reflected in the draft rule. The Commission is satisfied that this more preferable rule, having regard to the issues raised by Adani Renewables in its rule change request, will or is likely to better contribute to the achievement of the NEO than the solution proposed by Adani Renewables.  Its reasons are set out in section 2.5 below.

## 2.5 Summary of reasons

The Commission has considered the rule change requests submitted by Adani Renewables which proposed that the IRSR should be shared equally between customers and generators and that transmission loss factors should be calculated by an average loss factor methodology.

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the more preferable rule will, or is likely to, better contribute to the achievement of the NEO, by providing AEMO with greater flexibility when updating and refining the MLF methodology and calculating MLFs. This will support AEMO's work to improve the transparency and predictability of loss factors, in turn enabling better, more informed decision-making by prospective investors of generation assets, and by existing market participants in respect of the operation of existing assets.

In addition, the Commission is satisfied that the more preferable rule will, or is likely to, better contribute to the achievement of the NEO than the rules proposed by Adani Renewables for the following reasons:

- **Promotes efficient investment in electricity services** - By continuing the use of the current marginal loss factor methodology, important locational signals for prospective investors and owners of new generation assets will be preserved. Importantly, the strength of the locational signals provided under a marginal approach relative to an average approach, are needed to enable more informed and efficient decision-making about investment in the generation sector.

- **Promotes efficient operation of electricity services** - Use of a marginal loss factor methodology is consistent with the marginal approach currently used in the NEM for dispatch decision-making and pricing, thereby supporting efficient market operations. The continuation of a marginal approach also removes the risk that the use of an average loss factor may change the merit order to dispatch generators, resulting in less efficient use of the existing generation fleet to the detriment of the efficient operation of the NEM.
- **Promotes efficient risk allocation** - A marginal loss factor approach more efficiently allocates risk associated with investment decisions to those parties best able and willing to manage that risk (market participants and investors) as opposed to those who are unable to manage such risks (end-consumers).

These reasons are discussed in more detail below.

**Sharing intra-regional settlement residues**

In regard to the allocation of IRSR, the Commission has decided not to make a final rule in the form proposed by Adani Renewables. The Commission is not satisfied that making a change to the way intra-regional settlement residues are allocated is likely to better contribute to the achievement of the NEO for the reasons discussed below.

Adani Renewables proposed that amending the NER to require a reallocation of half the IRSR to generators was desirable to "offset" the negative impact that MLFs are currently having on owners of, and investors in, generation assets. However, making the proposed change would be likely to result in generation asset owners taking into account the anticipated effect of the IRSR in their bidding decisions. This may impact the order of dispatch of generators in the NEM, resulting in less efficient operation of the market. Additionally, this would represent a move away from the principle of marginal pricing, and as a result, be an economically inefficient arrangement.

In addition, to the extent that generators have regard to the anticipated flow of funds from the IRSR, this may dampen the desirable locational signals that MLFs provide to prospective investors in new generation assets. The Commission considers it important for the long term operation of the NEM that clear investment signals are provided to parties to encourage a variety of investors across a range of type and size of assets and locations in the market.

The Commission acknowledges that some stakeholders are seeking relief from the impact of unfavourable changes in MLF values. However, it considers that reallocating half the IRSR as proposed does not address the underlying cause of MLF volatility. It may be that consumers see some benefit in the proposed redistribution through lower wholesale electricity prices. However, it is unlikely that this would offset the increased TUOS charges that would also occur under this approach. Nor would the flow through of the IRSR to consumers be as certain as the current pass through arrangements in place. These impacts particularly concern the Commission in regard to the affordability of electricity services for consumers and making rules that will, or are likely to, contribute to the achievement of the NEO.

Many stakeholders did not agree with Adani Renewables' proposed change to the NER. They noted that currently the IRSR appropriately flows through to transmission customers and consequently consumers as it is these participants that fund investment in transmission infrastructure through TUOS charges. As discussed in Chapter 4, the Commission also considers this an important feature of the NEM which acknowledges the investment risk carried by consumers.

For these reasons, the Commission is not satisfied that the proposed change to reallocate half the IRSR to generators would, or would be likely to, contribute to the achievement of the NEO and be in the long-term interest of consumers.[32] Accordingly, the Commission has not amended the NER as requested by Adani Renewables.

### Using average loss factors

The Commission is not satisfied that a rule implementing an average loss factor methodology as proposed by Adani Renewables will, or will be likely to, better contribute to the achievement of the NEO than the current MLF methodology. The Commission considers that implementing an average loss factor would not provide clearer or more accurate long term investment signals nor support efficient dispatch in the NEM. Therefore would not be likely to better contribute to the achievement of the NEO.[33] Accordingly, having regard to the flow on effects to the affordability of electricity services for consumers, the Commission has not amended the NER to require AEMO to use an average loss factor methodology to determine transmission loss factors.

The Commission conducted concluded through its additional quantitative analysis which further evaluated the effects of moving from a marginal loss factor methodology to an average loss factor methodology. The results from this additional quantitative analysis found that:

- MLFs provide and maintain the most efficient locational and dispatch signals to the market
- aggregate customer payments would likely be higher under an ALF methodology
- the order of dispatch can change under an ALF framework and although in aggregate the effect of changing to ALFs on generator receipts is small, the change can have a significant effect on the revenue of individual generators.

In addition, the Commission has concluded that using average loss factors does not address the underlying issues regarding transmission and generation investment currently experienced in the NEM arising from the transformation of the sector. As set out in Chapter 5, there are a number of reasons for this conclusion:

- The current marginal loss factor methodology provides important locational signals for prospective investors and owners of new generation assets, which are needed to enable efficient decision-making about investment in the generation sector. This is particularly important in the current transformation of the electricity market.

32 This is discussed in more detail in Chapter 4.

33 This is discussed in more detail in Chapter 5.

- While an average loss factor method to determining transmission loss factors would be likely to result in a reduction in the volatility of loss factor values, it also dampens locational signals for new efficient generation investment needed for the future. This is undesirable in the current climate where it is important that a variety of type and size of generation assets are introduced across various locations in the market. It may also lead to more generation investment in inefficient locations, increasing physical transmission losses further. This would in turn require a greater amount of electricity to be generated which, in the long-run, would be likely to lead to higher electricity costs for consumers.
- The use of average loss factors to address concerns from some investors about revenue volatility and increases in their cost of capital does not outweigh the reduction in efficient investment signals and dispatch decisions that would occur across the NEM or the impact on the affordability of electricity for consumers.[34]
- Using a marginal loss factor methodology is also consistent with the marginal approach currently used in the NEM for dispatch decision-making and pricing, supporting efficient market operations.
- The use of an average loss factor may change the merit order to dispatch generators, resulting in less efficient use of the generation fleet and reducing the efficient operation of the NEM in real time. This may have the effect of wholesale electricity prices being higher than they would using MLFs.

In addition, the Commission notes:

- The COGATI review is considering how to introduce a dynamically set loss factor framework, which would address more holistically a number of issues outside the scope of this rule change.
- The final rule retains the benefits of the marginal loss factor approach while providing AEMO, in consultation with market participants, a greater ability to use different calculation techniques within that framework without impacting on accuracy. This enables AEMO to make refinements and improvements to the determination of MLFs consistent with the long term interest of consumers.
- While the loss factor values for many generators have materially declined over the last two to three years, other generators have not had this experience. A move to average loss factors would benefit some generators more than others, and would result in some generators being worse off. This is particularly the case for embedded generators located near major load centres and some batteries. For example, the recent indicative loss factors for 2020-2021 published by AEMO in November 2019 show that loss factors are forecast to worsen for some generators, but are expected to improve for many generators, with one of the largest improvements being for the Gannawarra Energy Storage System in Victoria, which has an indicative generation loss factor of greater than 1.0.

**Using other loss factor methodologies**

34 The impact on the cost of capital is explained in more detail within Chapter 5.

The Commission also considered whether methodologies other than average or marginal approaches should be used to determine transmission loss factors. However, none of the approaches that have the potential to be implementable through this rule change process (cap and collar, grandfathering, or the compression model) appear to be likely to better contribute to the achievement of the NEO than the current marginal approach. Similar to an average loss factor methodology, each of these approaches distort the investment location and operational dispatch signals provided by loss factors. As a result, they raise significant concerns for efficient investment in, and operation of, the NEM because they are likely to transfer risks and costs either to other generators or to consumers. Further discussion on these methods is set out in Appendix D to this final rule determination.

Two other potential approaches to calculating transmission loss factors — recovering all costs from customers (as occurs in the Italian electricity market) and dynamic loss factors — were also suggested by stakeholders during this rule change process. Both of these approaches integrate transmission loss factors into the operation of the electricity market. As a result, significant reforms to the operation of the NEM would be required if either of these approaches were to be implemented. The considerations required to make a decision on a more market integrated loss factor approach are more appropriately considered under broader projects such as the Commission's COGATI review. The COGATI review considers more issues and is able to appropriately consider the longer term, fundamental reforms for the NEM and address the root causes of the recent variability of MLF values. This supports efficient transmission and generation investment as Australia moves toward a low carbon economy. Other relevant changes and reforms are discussed below.

**Other changes and reforms**

The Commission's decision not to implement the changes proposed in the rule change requests has been made in the context of other changes and reforms currently in progress.

First, concerns expressed by many stakeholders regarding their ability to understand the changing market and, in particular, the prospects for investing in the generation sector. These concerns are addressed by the amendments to the NER made through the Transparency of new projects rule change. This new rule, published on 24 October 2019, will make more information about new generation projects more readily available, and provide for more regularly updated data on existing and proposed connections of generating plant to the national grid.

The Transparency of new projects rule is an important and practical amendment to the NER that will enable better informed investment decision-making to occur, reducing the likelihood of electricity users paying for inefficient investments. In addition, it will enable existing owners of generation assets to be better informed about market developments and the impact this may have on their business.

Second, some improvements to the MLF methodology and information about MLFs can be made by AEMO without any amendments to the NER. Specifically, AEMO has:

- commenced work on more frequent publication of MLF values for information and transparency purposes, with the first quarterly report released in November 2019

- undertaken to review the methodology through a consultation process with stakeholders to improve accuracy, efficiency and transparency of the MLF methodology following publication of the 2020-2021 MLF values in April 2020
- continued to improve generation investment information available on its generation information webpage, including information on transmission connection applications and enquiries.

These developments work with the Transparency in new projects rule to improve information available to prospective investors and existing generators. The Commission and AEMO encourage stakeholders to engage in AEMO's processes to make these improvements that should result in a greater understanding of the methodology and the movement of the MLF values over time, enabling more informed decision-making to occur.

**Final rule**

Consistent with the work to be undertaken by AEMO, the Commission has made amendments regarding the MLF framework in the final rule. These amendments enable AEMO to consult with stakeholders on a greater range of alternative calculation details to refine and improve the MLF methodology while maintaining accuracy and providing clear, efficient locational and dispatch signals to the market. The final rule:

- removes the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- removes the requirement that MLF values must be based on a period of 30 minutes to allow greater time periods to be used as the basis for calculating MLF values
- removes the requirement that MNSPs be treated as invariant in the calculation of MLFs so that AEMO could forecast variable MNSP behaviour in its modelling.

The Commission is satisfied that, having regard to the issues raised in the rule change request, this more preferable rule will or is likely to better contribute to the achievement of the NEO than the proposals made by Adani Renewables. This is because it improves flexibility for AEMO, in consultation with market participants, to determine alternative calculation methodologies for MLFs that may produce more accurate results. In addition, with the greater flexibility, AEMO would be able to refine the MLF calculation process so that it is more transparent and understandable for market participants. This in turn may support better decision-making for investments by prospective owners of generation as well as for AEMO in the operation of the NEM.

The Commission has further considered the views of stakeholders in identifying the issues raised in Adani Renewables' rule change requests. It has concluded that the recent volatility of MLF values and the observation that the IRSR has been significant are symptoms of broader issues in the NEM. Specifically, that a significant amount of new generation is locating on the periphery of the NEM, away from key demand centres, to suit fuel sources such as solar or wind. However, the transmission system is relatively weak at these locations and investment in transmission capacity (either under TNSP regulated revenue or by other parties) has not kept up with the increased generation capacity installed at these particular locations. Despite the volatility of the MLF values, and some connection nodes experiencing declining MLFs recently, the market is continuing to see development of new generation assets in those same locations. . This is exacerbating actual electrical losses on transmission lines and the future volatility in MLFs.

These issues reflect a broader set of generation and transmission investment issues that the Commission is considering in detail in its COGATI review. The work carried out in this review indicates that the current lack of coordination between generation and transmission system investment requires significant reforms to the NEM to make long term, robust improvements to the way investment is carried out for the long term benefit of consumers. Through the review, the Commission is developing a new access model, based around locational pricing (dynamic regional pricing) and financial transmission rights. Consideration of such changes are beyond the scope of this rule change process, which can only consider issues regarding the MLF and the IRSR frameworks.

The access model being developed through the COGATI review may include, within its pricing mechanism, marginal loss factors set on a dynamic basis. The review is also considering the design of the financial risk management products that would be made available, including how these could best allow participants to hedge against changes in the loss factors. Accordingly, the Commission considers that the COGATI review and other reforms provide the most appropriate forum for stakeholders to engage in discussing and assessing potential holistic reforms that may be able to better address the fundamental problems causing the variability and unpredictably recently seen in MLF values, to provide a long term solution. This may include a move to locational pricing (dynamic regional pricing) with financial risk management tools.

The Commission also notes that its work in the COGATI review is one action aimed to address the issues arising from the current transformation of the electricity market. Other key work is being undertaken by the Energy Security Board (ESB). Specifically, to action the Integrated System Plan (which will govern future transmission planning and investment processes) and develop a post-2025 market design for the NEM. In the interim, greater use of diversification in investments provide opportunities for investors to manage the uncertainties in transmission loss factors.

## 2.6 Climate change related issues

The Commission notes that climate change is a significant issue that has ramifications for policy decisions. The Australian Government, through the United Nations Framework Convention on Climate Change (UNFCCC) and Conference of the Parties (COP) process has agreed:

- warming should be limited to two degrees Celsius above pre-industrial levels with an aspiration to limit to 1.5 degrees
- the initial target for Australia is to reduce emissions by 26-28 per cent relative to 2005 levels by 2030.

The Commission makes its decisions on rule change requests under the NER by reference to the NEO. This objective does not expressly require the Commission to have regard to the long term interests of consumers with respect to climate change or the environment. However, in making its decisions under the NER the Commission also has regard to relevant factors that can impact on the specific matters identified in the NEO. In relation to climate change this includes consideration of:

- how the physical world is changing or likely to change as a result of climate change (adaptation risk)
- how policy makers, consumers and investors are responding, or are likely to respond, to the risks presented by climate change (mitigation risk)

to the extent that these factors have an effect on the specific matters included in the NEO.

The final rule itself will not adversely affect either adaptation or mitigation efforts, or result in an increase in either mitigation or adaptation risk. This is because, relative to the existing framework in the NER, the only effect of the final rule is to provide additional flexibility for AEMO to revise and improve the current approach to determining marginal loss factors, which will, or is likely to, assist investors and existing market participants to make more informed investment and operational decisions.

The Commission has considered the extent to which the risks associated with climate change adaptation and mitigation have an effect on specific matters included in the NEO, and has subsequently considered the relative merits of making the rule change request as proposed by Adani Renewables in that context.

The Commission considers that its decision not to make the rule as proposed by Adani Renewables will not increase mitigation risks or undermine emissions reductions efforts. This is because retaining the existing marginal approach to calculating transmission loss factors will avoid the risk of more physical losses occurring on the system as a result of diminished locational signals (longer-term) and changes in dispatch (short-term) arising from a move to ALFs. Both the proposed Rule and the Commission's final Rule are unrelated to adaptation risk, and therefore the final Rule doesn't adversely affect adaptation risk.

The Commission notes that the recent volatility seen in marginal loss factors values is but one of the issues that influence investment decisions in new generation technology. As discussed in this final rule determination, other, more pressing, reasons for the decline include significantly longer time-frames for connecting and commissioning new plant, security output constraints, congestion risk and energy and emissions policy uncertainty. This is discussed in more detail throughout Chapter 3.

## 2.7 Implementation of the final rule

The purpose of the final rule is to provide AEMO with greater flexibility when updating and refining the MLF methodology and calculating MLFs. This is relevant when AEMO carries out a consultation process on the MLF methodology which may occur at any time.

Schedules 1 and 3 of the final rule will commence on 5 March 2020. Schedule 2 of the final rule will commence on 1 July 2021, immediately after commencement of Schedule 2 of the

*National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019 No. 7*.

# 3 ISSUE IDENTIFICATION

This chapter assesses the problem that Adani Renewables has suggested exists within the current MLF arrangements and outlines the issues that stakeholders have identified as the cause of the recent changes in MLF values.

It also provides the Commission's analysis of the factors causing the changes in MLF values, and discusses the impact this might be having on existing and new investors in generation assets. This chapter also sets out the Commission's views on future actions that can be taken in response to recent market changes.

## 3.1 Adani Renewables' views

The proponent's two rule change requests suggest that the current provisions in the NER relating to MLFs are resulting in high inaccuracies in MLF values although it does not specifically identify these provisions.[35]

Adani Renewables argued that the inaccuracies in the MLF calculations are the cause of the variability in the MLFs in that:[36]

> The IRSR is a representation of the cumulative error between actual marginal loss factors and forecast losses, with this error arising through generation patterns from year to year and forecasting errors.

Adani Renewables stated that this is resulting in market participants bidding higher spot prices to cover the declining losses due to perceived inaccurate MLF values. In both rule change requests, it stated that:[37]

> MLFs are impacted by the current rule as they end up with higher effective bid prices as a result of the inaccurate MLF and potentially will not be dispatched.

Adani Renewables also stated that the current rules are out-dated and therefore distorting the market through inefficiencies in operational and investment decision-making.[38]

In addition, it argued that inaccuracies resulting from the current methodology for MLFs prescribed in the NER mean that generators are receiving artificially low MLFs.[39]

## 3.2 Stakeholder views on the request

In the consultation paper the Commission requested stakeholders consider what could be causing the observed changes in MLF values. The Commission sought feedback on whether the operation of the loss factor provisions in the NER as identified by the proponent was the

35 Adani Renewables, rule change request, 27 November 2018, covering letter; Adani Renewables, rule change request, 5 February 2019, covering letter. The relevant provisions are clauses 3.6.1, 3.6.2, 3.6.2A of the NER.

36 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

37 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

38 Adani Renewables, rule change request, 27 November 2018, covering letter.

39 Adani Renewables, rule change request, 27 November 2018, p. 10; Adani Renewables, rule change request, 5 February 2019, p. 10.

cause of the problem. It also asked if there were other issues which stakeholders considered impacted on the transmission loss factor framework.

### 3.2.1 Stakeholder responses to Adani Renewables' views

Stakeholder submissions were diverse in opinion as to the cause of year-on-year variability of MLFs in the NEM. Although stakeholders' views varied, there was broad support that the determination of transmission loss factors should be reviewed.

While a number of stakeholders expressed agreement with Adani Renewables' characterisation of the problem, they also considered a number of other contributing factors are causing the variability in MLF values.

#### Is there an accuracy problem with MLFs?

The consultation paper sought stakeholders' views on whether they agreed with Adani Renewables that the current MLF calculation methodology produces inaccuracies. The majority of stakeholders considered that the current MLF methodology has a level of inherent inaccuracy; as a result of being marginal and an annual forecast. However, stakeholders were divided on whether this was problematic.

The ACT Government EPSDD articulated this and submitted that:[40]

> ...like any forecast, there will always have some inaccuracy, and in some cases may have significant inaccuracies. EPSD notes three sources of inaccuracy that can be observed under the current marginal loss factor framework:
>
> - The use of forecast losses, rather than actual losses;
> - The use of marginal losses rather than average losses; and
> - The use of static, rather than dynamic losses.
>
> However, inaccuracy in the AEMO's loss factor methodology would only have a material impact on the long-term interest of consumers, and therefore contravene the NEO, if it is both significant in its magnitude, and consistent in its direction.

Some stakeholders, although acknowledging the current methodology includes some inaccuracy, did not consider this was problematic. ERM Power submitted that:[41]

> …there is an inherent level of inaccuracy in the current methodology for the calculation of transmission loss factors as it is heavily reliant on a high correlation between forecast and actual outcomes for accuracy. Whilst it can be taken as given that there will be a level of inaccuracy with regards to the calculation of forward-looking loss factors compared to actual losses, it is unclear how material the impact of this is on dispatch efficiency, and longer term investment signals, particularly given the large gaps between short-run marginal costs between generation technologies in the National Electricity Market (NEM) absent the provision of any supporting analysis.

40 ESPDD submission to the consultation paper, p. 3.

41 ERM Power submission to the consultation paper, p. 2.

Other stakeholders simply considered that because the current methodology is forward-looking and the calculation is marginal in nature, there is an inherent level of inaccuracy.[42]

EnergyAustralia commented that there is limited data to support the assertion that the current rules result in high inaccuracies and hence distort the market through inefficiencies in operational and investment decision-making.[43] This was also noted by Origin.[44]

Intelligent Energy Systems (IES), submitted that the changes in MLF values can not all be attributed to the MLF methodology, but the recent changes in values do prompt a search for ways to do things better.[45]

In its submission, the Australian Energy Council (AEC) considered the origins of the current methodology:[46]

> The NEM however deliberately chose a simplification - hub and spoke regions combined with annual static intra-regional loss factors. It was considered that the simplifications of such an approach, with its advantages in supporting the contract markets, justified the resulting inaccuracies.
>
> This trade-off was analysed in detail by the National Electricity Market Management Company (NEMMCO) in the first years of the NEM. Their analysis quantified the error by comparing static loss factors to actual marginal losses. At the time, the error was considered acceptable, but this was in a market characterised by non-variable sources of generation and a reasonably predictable investment pipeline. These conditions have significantly changed, and it is appropriate to recalculate this error.

Energy Networks Australia (ENA) similarly noted that:[47]

> Adani suggest that there are errors in the MLF framework, however this difference is consciously embedded in the market design and is one of the many trade-offs.

Further, EnergyAustralia submitted that errors will always result in inaccuracies or rather variability in the calculation of loss factors regardless of the choice of using MLFs or ALFs.[48] Ergon Energy and Energex similarly noted that any methodology that predicts future marginal loss factors will be an estimate, meaning any implemented proposal could be construed as "inaccurate".[49]

#### What is the impact of recent MLF values?

In contrast, some stakeholders did consider that the current methodology is problematic. CEC submitted that the current loss factor approach has resulted in significant year-on-year

42 Submissions to the consultation paper: AusNet Services, cover page; Origin, p. 1.
43 EnergyAustralia submission to the consultation paper, p. 4.
44 Origin submission to the consultation paper, p. 1.
45 IES submission to the consultation paper, p. 2.
46 AEC submission to the consultation paper, p. 3.
47 ENA submission to the consultation paper, p. 4.
48 EnergyAustralia submission to the consultation paper, p. 4.
49 Ergon Energy and Energex submission to the consultation paper, attached table.

variations in MLF values.[50] More specifically, Lighthouse Infrastructure commented that an "MLF is an inaccurate reflection of losses; in fact it is worse than inaccurate, it is a systematic exaggeration of losses".[51] It expanded on this point, commenting that the inaccuracies in the methodology are problematic and that the degree of over-recovery is greater when the underlying losses are greater, as there is now a trend toward greater losses due to fringe of grid renewable developments.[52]

This point was also raised by Powering Australian Renewables Fund (PARF) who submitted that the variability of MLF values is compounded via the rate of change and assumptions being made on timing of connection and generation profiles for competing generators as well as interconnector flows which are all inputs into the current calculation methodology.[53]

Lighthouse Infrastructure further considered that the inaccuracies of the current methodology are a major impediment to investment in new renewable generation which is causing inflated electricity prices to persist, undermining the NEO. It also submitted that the result of inaccuracies and "unnecessary losses will increase the cost of electricity for consumers".[54] In addition, Lighthouse Infrastructure considered that the unpredictability of losses is as much of a barrier to efficient investment as the absolute levels of the MLF values. It stated that the annual resetting of loss factors that creates this unpredictability does not represent a useful economic signal.[55]

The Clean Energy Investor Group (CEIG) [56] (whose submission was provided by John Laing on behalf of the group) also considered the impact of the current MLF calculation methodology producing inaccurate results, and submitted that the Commission should consider the theoretical lens in which it is being examined. The CEIG suggested that viewed through an economic lens, the current methodology offers a theoretically sound basis for signalling efficient generation and investment decisions. However, when viewed through a project finance or technical lens, it could be deemed less accurate than a methodology such as the ALF methodology given its propensity to over-recover IRSR year-on-year.[57]

QIC expressed similar views to Adani Renewables. It also linked inaccuracies in the current calculation methodology with unpredictable MLF values. It stated that:[58]

> …the current methodology of utilising a marginal loss factor as a proxy for transmission losses produces unpredictable results, and that alternate transmission loss estimation

50 CEC submission to the consultation paper, p. 1.

51 Lighthouse Infrastructure submission to the consultation paper, p. 2.

52 Lighthouse Infrastructure submission to the consultation paper, p. 2.

53 PARF submission to the consultation paper, p. 2.

54 Lighthouse Infrastructure submission to the consultation paper, p. 2.

55 Lighthouse Infrastructure submission to the consultation paper, p. 2.

56 The Clean Energy Investor Group includes: Ararat Wind Farm Pty Ltd, BayWa r.e Solar Projects Pty Ltd, Blackrock Investment Management (Australia) Ltd, Epuron Projects Pty Ltd, ESCO Pacific Pty Ltd, Foresight Group Australia Pty Ltd, FRV Services Australia Pty Ltd, Infrastructure Capital Group Ltd, Innogy Renewables Australia Pty Ltd, Laing Investments Management Services (Australia) Ltd, Lighthouse Solar Management Pty Ltd, Macquarie Corporate Holdings Pty Ltd, Neoen Australia Pty Ltd, Pacific Hydro Investments Pty Ltd, Palisade Investment Partners Ltd, PARF Company 2 Pty Ltd (Powering Australian Renewables Fund), Total Eren Australia Pty Ltd, Windlab Ltd and Wirsol Enregy Pty Ltd.

57 CEIG submission to the consultation paper, p. 13.

58 QIC submission to the consultation paper, p. 3.

> methods, would yield more stable estimates and provide a higher degree of certainty for generators. This is particularly the case for generators located on the fringe portions of the transmission network which is where the majority of Australia's wind and solar resources are. Given that between $8-27bn in new investment is forecast to be required to replace retiring generation capacity and meet demand growth, it is paramount that the transmission loss factor methodology ultimately adopted is able to, and is perceived to be able to, deliver stable and reliable results.

A number of stakeholders who have a relationship with MLFs through financing or investing (debt and/or equity) in new generation in the NEM expanded on the points above and considered the current arrangements problematic as they are increasing the cost of capital for investment in new generation, which will ultimately be passed onto consumers.[59]

Stakeholders who considered the inaccuracies resulting from the current MLF calculation arrangements as problematic also considered other contributing factors. For example, AGL submitted that the design of the current MLF methodology and the NER are in part associated with the decreases in MLF values through static, yearly MLF values.[60]

### 3.2.2 Other impacts on the transmission loss factor framework

Stakeholders also identified a number of other contributing factors that they considered were causing problems with the transmission loss factor framework which are resulting in the observed volatility of MLF values in the NEM.

AGL submitted that other attributes that could be attributed to the changes in MLF values such as:[61]

> ...the growing rate of renewable generators seeking connection to the grid and their level of understanding of the NEM, the NER and the role of MLFs; and/or the lack of information and general transparency about other developments taking place in a defined region (and the uncertainty and volatility this creates in the minds of debt and equity financiers).

AGL further noted that the largest impacts of changing MLF values are seen where there is "a combination of high renewable penetration, lower grid strength and are situated further from large load centres."[62]

Many stakeholders submitted that the rapid transformation of generation in the NEM is contributing to unpredictability and variability in the NEM.[63] These stakeholders identified a number of features of the transformation, such as significant development of new generation in remote parts of the NEM in addition to co-location, that they considered have impacted on

59 Submissions to consultation paper: CEIG, PARF, QIC, Lighthouse Infrastructure, CEC supplementary submission.

60 AGL submission to the consultation paper, p. 2.

61 AGL submission to the consultation paper, p. 2.

62 AGL submission to the consultation paper, p. 1.

63 Submissions to the consultation paper: Origin, p. 3; First Solar, p. 2; CEIG, pp. 4, 6; EnergyAustralia, cover page and p. 4; PARF, pp. 1, 2, 9; Major Energy Users Inc, p. 3; CEC, Baringa report, p. 5; SnowyHydro, cover page; EUAA, p. 1; AGL, p. 2.

loss factor values. These features are further exacerbated by inadequate coordination of transmission infrastructure development to support the new generation.[64] PARF submitted that as:[65]

> ...the NEM transitions to low carbon resources, generators will increasingly be located in areas where the transmission network was not originally designed for them. This has placed, and will continue to place, strain on the network in these areas. As more and more new generators connect to 'untraditional' areas, power flows and therefore losses on the network increase…

Origin submitted that there are two factors contributing to investments being made that are potentially inconsistent with MLF signals:

- a potential disconnect between generation project developers and the ultimate operators of a facility – it is possible insufficient regard is being given to the impact of transmission losses on the economic viability of a generation project during the initial development phase, where the primary factor driving site selection may be access to the associated fuel resource (e.g. wind); and
- a general lack of transparency around the status of prospective generation projects and their potential network impacts – where a developer's ability to assess the potential impact of its prospective generator is impeded, or there is a lack of visibility around other prospective projects, this could lead to inefficient investment decisions such as generators co-locating in the same area to their own detriment from a loss factor perspective.

The first factor identified by Origin of a lack of coordination between generation project developers and the ultimate operator of a facility was also noted by SnowyHydro and AGL.[66] Similar points were raised by EnergyAustralia, who considered that:[67]

> The speed at which new renewable projects can be financed, installed and commissioned has led to large changes in MLFs...

In reference to the speed of change occurring, the CEIG and First Solar submitted that there is an information asymmetry problem resulting in consultants not being able to provide the best possible forecasts for potential developments.[68]

Similarly, some stakeholders suggested that there is a general lack of transparency around prospective generation projects and their potential network impacts which is also an underlying problem that impacts on loss factor values.[69] However, most of these stakeholders

64 CEC submission to the consultation paper, Baringa report, p. 6.

65 PARF submission to the consultation paper, p. 5.

66 SnowyHydro submission to the consultation paper, p. 2; AGL submission to the consultation paper, p. 2.

67 EnergyAustralia submission to the consultation paper, cover page.

68 CEIG submission to the consultation paper, p. 5; First Solar submission to the consultation paper, p. 7.

69 CEIG submission to the consultation paper, p. 5. See also submissions to the consultation paper: First Solar, p. 7; Origin, p. 3; Stanwell, p. 2; EnergyAustralia, p. 4.

did acknowledge that this was being addressed through the Transparency of new projects rule change that took effect in December 2019.

## 3.3 Draft rule determination

In the draft rule determination, the Commission recognised market participants' concerns in relation to MLFs were volatility, unpredictability and the associated costs of year-on-year changes in MLFs.

The discussion below sets out the Commission's draft rule determination analysis. It includes the following aspects:

- transformation of the NEM
- accuracy of MLFs
- changes in MLF values
- impact of MLFs on investment
- impact of MLFs on the cost of capital.

### 3.3.1 Transformation of the NEM

The Commission outlined in its consultation paper that MLFs were previously reasonably predictable with little variability. This reflected the stability of the generation sector: much of the electricity supply in the NEM was provided by relatively few, large generators with reasonably consistent and forecastable dispatch patterns. In addition, many of these generators were securely connected (that is, connected with high voltage and low resistance transmission lines) to enable reliable supply to key demand locations.[70] Under these circumstances, market participants were better able to estimate future MLFs for a connection point. This allowed market participants to have more confidence of the impact of MLFs on their operational and investment decisions.

As noted in the draft rule determination, stakeholders have acknowledged a number of recent changes in the NEM are together contributing to the unprecedented change in the market as illustrated by changes in MLF values. In particular:

- new generation assets are being connected in remote parts of the NEM, that are a significant distance from demand centres, due to the location of certain fuel sources
- the new generation plants connecting often have correlated, rather than offsetting, dispatch characteristics
- co-location of new and often similar generation assets has been occurring
- the transmission infrastructure in those areas was not originally designed to support large-scale generation flows.

The Commission noted that these fundamental changes are resulting in greater physical losses of electricity, which is not a function of economic theory but rather a function of physics. There are also additional factors, as indicated by stakeholder submissions, that do

70 AEMC, *Transmission loss factors*, consultation paper, pp. 5-6.

not directly create electrical losses but are market dynamics that are intensifying the variability and unpredictably of MLF values. Specifically:

- the rapid pace of investment and the related speed of construction with which new generation assets can be built relative to conventional assets (see Appendix E)
- a potential lack of coordination between generation project developers and the ultimate owners and operators of a facility.

The changes identified above have created more real physical electrical losses, which are evident and represented through the increased losses embodied in AEMO's annual MLF publications. The Commission stated in its draft rule determination that it did not agree with Adani Renewables that there are "high inaccuracies" resulting from the use of a marginal and forward-looking calculation methodology. Instead, it noted that it is the factors noted above which are the fundamental cause of increased electrical losses, and the variability and unpredictably of MLF values.

### 3.3.2 Accuracy of MLFs

As part of its rule change request, Adani Renewables argued that MLFs are inaccurate[71] and that this inaccuracy results in the current variability in MLFs.[72]

The Commission undertook its own analysis for the draft rule determination to test if MLFs are inaccurate and to test the scale of variability in MLFs (section 3.3.3 below). On the first of these points, the Commission's analysis indicated that overall, MLFs have been reasonably accurate. The Commission also noted that MLFs are annual forecasts based on historical data and that any such forecast is likely to result in variances from actual, subsequent results.

Forecasts are generally considered efficient if they are unbiased. From the information in Figure 3.1 below, the Commission could not detect a bias in MLF forecasts. The Commission noted that the objective of published MLFs is not to achieve an exact forecast of transmission losses but to provide efficient location and dispatch signals.

MLF values in Figure 3.1 were from published MLFs and a recalculated MLF value for the same year using backcast data. Data points were grouped into sub-region groups which have been given generic names. The difference between the two estimates represents the impact of additional information AEMO obtained between the time the MLF values were first published and actual generation data obtained later. For example, for region NSW-4, the published MLF was 0.03 points higher than the backcast MLF. Conversely, for region VIC-5, the published MLF was 0.06 points lower than the backcast MLF.

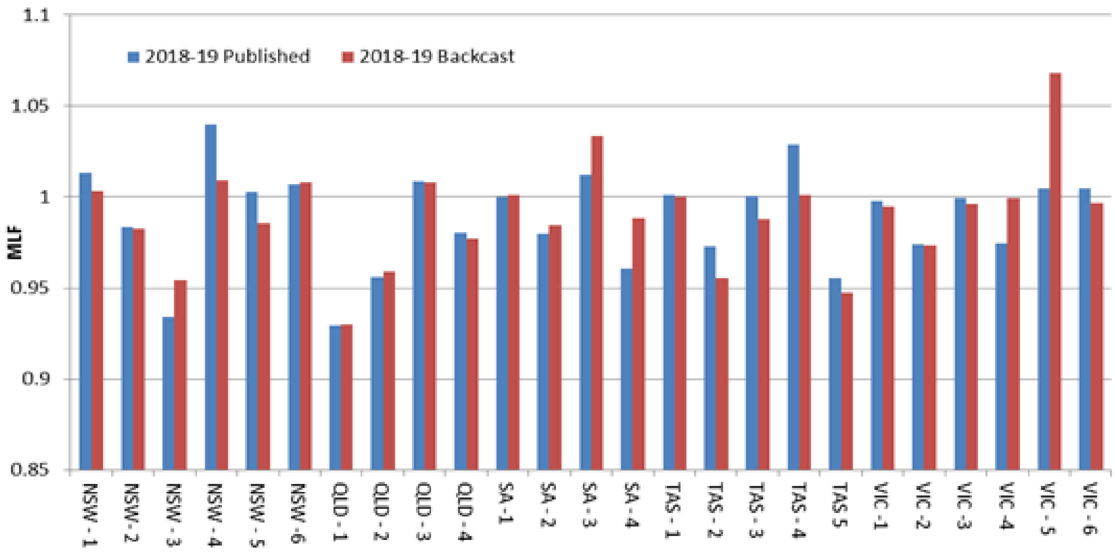
As a result, the Commission observed that there was no systemic difference between published MLFs and recalculated MLFs using backcast data. In some regions, the published MLF is higher than the backcast MLF while in other locations, the published MLF is lower than the backcast MLF. The chart also shows that the biggest difference between the published

71 Adani Renewables, rule change request, 27 November 2018, covering letter; Adani Renewables, rule change request, 5 February 2019, covering letter.

72 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.

and backcast MLFs in 2018-2019 is 0.06 points for region VIC–5. This indicates that AEMO's MLF forecasts are efficient, unbiased forecasts.

**Figure 3.1: Published and backcast MLFs for 2018-2019**




Source: AEMO
Note: This graph shows the difference between published MLFs and backcast MLFs for the same year. This type of analysis shows that difference between forecast MLFs (the published MLF) and the updated MLF (backcast MLF), using actual data from the year the MLF is estimated for. The lower the difference between published and backcast MLF, the higher the accuracy of the forecast.

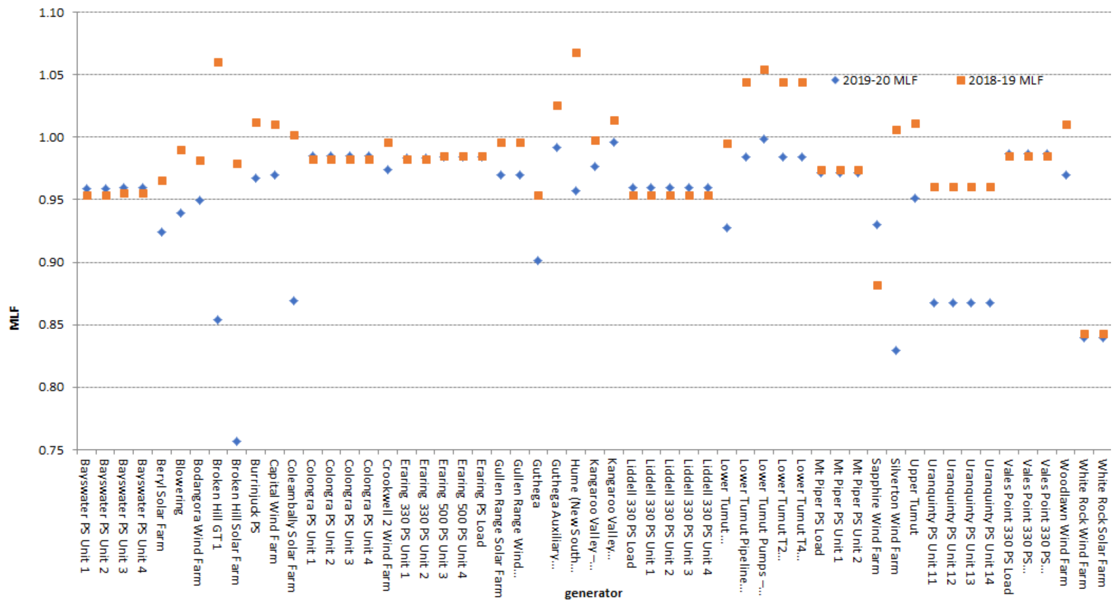
### 3.3.3 Changes in MLF values

Some stakeholders submitted that they are concerned about declining and volatile MLFs that have not been predictable. In particular, they noted that declining MLFs affect revenue and consequently may have an impact on the cost of capital paid to fund investment in generation assets.

As part of the draft rule determination, the Commission tested these assertions against recent changes in MLF values in the NEM and found that while MLFs change, the larger declines are generally occurring in locations with significant network congestion. This was expected as MLFs have been designed to provide efficient locational signals for new assets (as well as achieve efficient dispatch).

Figure 3.2 shows the change in MLFs for NSW generators from 2018-2019 to 2019-2020. While most base load generators have stable MLFs, there have been significant declines for some generators (namely, Broken Hill GT1, Broken Hill Solar Farm, Coleambally Solar Farm, Hume and Silverton Wind Farm). Declining MLFs can affect new entrant generators as well as incumbents. For example, MLFs declined by 23 per cent for Broken Hill Solar Farm and 19 per cent for Broken Hill GT 1 between 2018-2019 and 2019-2020. However, there have also been increases in MLFs for renewable generators. For example, Sapphire Wind Farm’s MLF increased by 5.4 per cent between 2018-2019 and 2019-2020. While the data in this figure focuses on NSW, the Commission's analysis has indicated similar trends have occurred in Victoria and Queensland. Generation MLFs seem to have been more stable in Tasmania and South Australia.

## Figure 3.2: Changes in MLFs in NSW, 2018-2019 to 2019-2020




Source: AEMO

Note: The graph shows the change in MLF values for NSW generators between 2018-19 and 2019-2020. The orange markers are the 2018-2019 MLFs and the blue markers are the 2019-2020 MLFs.

The Commission's draft rule determination analysis indicated that some generators have experienced a decline in MLF values. However, the analysis also indicated that many generators have not had this experience.

On 1 November 2019, AEMO published indicative MLFs for the 2020-2021 financial year.[73] The indicative MLFs were provided to provide an early indication to stakeholders of the potential direction and the extent of movement in MLFs across the NEM.

The indicative figures for 2020-2021 show that MLFs for some generators are continuing to decline, while the MLFs of other generators are increasing. For example, Broken Hill solar farm and Silverton wind farm in NSW are shown to continue their decline (4.2 per cent and 3.5 per cent respectively). In contrast, generators in north and far north Queensland are anticipated to experience increases in their MLFs. For example, Hughenden, Kidston and Ross River solar farms are expected to increase by 3.17 per cent and Daydream solar farm by 2.6 per cent. The Gannawarra Energy Storage System is a 25 MW/50 MWh Tesla Powerpack battery to be integrated with the 50 MW [Gannawarra Solar Farm] located west of Kerang in north-west Victoria. It is to become the first integrated solar and storage project in Victoria and among the largest of its kind in the world. Its generation and load MLFs are both

73 AEMO, *Indicative marginal loss factors: FY 2020-21*, November 2019.

forecast to improve by between four and six per cent, with its generation MLF forecast to be greater than 1.0.

The most efficient way to address the issue of volatile loss factor values is to move to dynamic marginal pricing with financial risk management tools. The draft rule determination noted that while this was not immediately possible, and not within the scope of the rule change process, the Commission did not consider that changing from MLFs to an alternative interim methodology would, or would be likely to, contribute to the achievement of the NEO. This was because an interim measure would be likely to introduce inefficiencies into the market (in regard to investment and operation of generation assets) and make any step change to dynamic pricing, if and when it were to occur, more significant.

In relation to the concerns about predictability of the movement in MLF values, the Commission noted in the draft rule determination that the changes made to the NER through the recent Transparency of new projects rule change were relevant. In addition, the Commission acknowledged AEMO's work plan to refine the MLF methodology through a consultation process with stakeholders which would also assist stakeholders in managing changing MLF values in the future.

### 3.3.4 Impact of MLFs on investment

In response to the consultation paper, stakeholders submitted that the recent decline and volatility in MLFs could potentially result in a decline in investment in Australian generation assets.[74] To understand this further for the draft rule determination, the Commission undertook its own analysis using data published by AEMO and found that:

- committed generation investment has come down from relatively high levels in 2018 and 2019
- proposed investment was strong in July 2019
- proposed investment as at July 2018 was mostly in renewable generation (87 per cent of total proposed generation investment).

#### Committed and proposed investment in generation assets

Figure 3.3 illustrates the trend in committed and proposed generation investment in the NEM between August 2016 and July 2019. The graph shows that there was a substantial increase in committed investment between July 2018 and January 2019 which coincides with ramping up in the large-scale renewable energy target (LRET).[75] After January 2019, there was a significant drop in committed generation investment reflecting a combination of the RET being largely met, but also other factors, such as security output constraints, congestion risk and energy and emissions policy uncertainty.

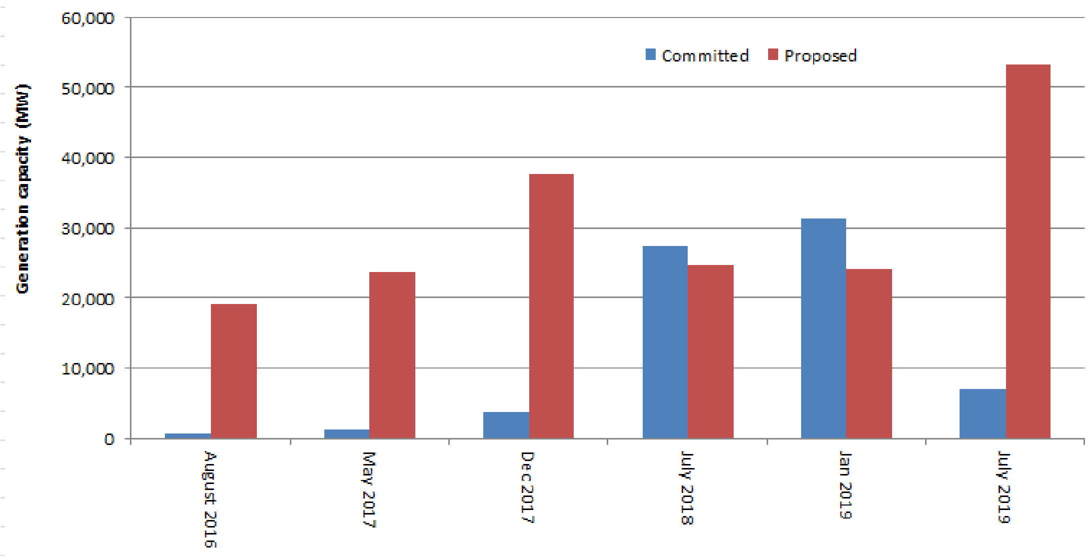
Nevertheless, proposed generation investment remained high in July 2019. The Commission noted that in July 2019, proposed investments were mostly in renewable generation assets

74 For example, submissions to the consultation paper: CEIG, PARF, p. 5; CEC supplementary submission, p. 1.

75 The LRET was designed to incentivise investment in renewable energy generation assets to assist Australia in reaching its goal of 20 per cent of renewable energy by 2020.

with solar making up 46 per cent of proposed investment in July 2019, wind 31 per cent and pumped hydro 10 per cent. Proposed investment in gas-fired generation plants was low at around three per cent.

Figure 3.3: Committed and proposed generation investment in the NEM




Source: AEMO
Note: The graph shows committed and proposed generation investment published by AEMO.

### Recent investment in generation assets

Investment activity in the Australian electricity sector was also considered by the Commission in making its draft rule determination. The information available indicated that there was new debt capital entering the Australian capital market. For example, UK-based infrastructure and private equity investment manager Foresight Group launched a new product, the Foresight Renewable Energy Income Fund, in Australia. The fund planned to target $150 million and make loans of $5 million to $30 million, mainly to small-scale solar and wind and associated infrastructure projects.

According to the Foresight Group, small-scale solar in Australia is forecast to grow rapidly, faster than any other form of energy generation. And, unlike larger-scale renewable projects, smaller projects have lower connection costs and can be located close to demand centres, making them more efficient as electricity that is generated will travel shorter distances.[76] According to the Foresight Group, the fund will capitalise on the inefficiencies in the Australian debt market that have left small-scale renewables projects underserved.[77] It

76 https://www.foresightgroupau.com/foresight-renewable-energy-income-fund/ Accessed 28 October 2019.

77 https://www.foresightgroupau.com/foresight-renewable-energy-income-fund/, https://www.thefifthestate.com.au/business/investment-deals/foresight-group-launches-fund-for-small-scale-renewables/ Accessed 28 October 2019.

planned to target a 4.0-4.5 per cent yield margin over the Reserve Bank of Australia (RBA) cash rate. Assuming a yield of four per cent, this would mean a credit spread of 2.8 per cent (over the nominal risk free rate of 1.2 per cent as at July 2019). This is significantly higher than the current credit spread on BBB rated non-financial debt which was 1.41 per cent in July 2019.

The Foresight Group's Australian solar portfolio currently includes:

- Bannerton, Victoria (110 MW)
- Oakey 1, Queensland (30 MW)
- Oakey 2, Queensland (70 MW)
- Longreach, Queensland (17 MW)
- Barcaldine, Queensland (25 MW).

#### Asset valuations of investments

The draft rule determination also noted that one consideration of investors is the value of the assets in which they invest and how this value holds over time. As a result, one of the factors to consider in addition to MLF risk and its impact on generation investment are asset valuations. Assets that are relatively over-valued would be relatively more affected by declining MLFs compared to assets that are valued closer to their intrinsic value. This is because an over-valued asset will require relatively higher cash flows to achieve the required rate of return of an investment made. For example, in a recent survey of renewable energy investors, Minter Ellison identified that the three most significant challenges investment in Australian renewables in the next 12 months were:[78]

- valuations (too high), 62 per cent of respondents
- complexities/uncertainties created in transitioning to renewables-based grid, 58 per cent of respondents
- instability around incentives, 57 per cent of respondents.

### 3.3.5 Impact of MLFs on cost of capital

A number of stakeholders submitted to the consultation paper that declining MLFs may result in an increase in the cost of capital. If this occurred, it would be likely that this would lead to an increase in consumer prices for electricity. Alternatively, this could deter investors in committing new funds to Australian generation assets.[79]

In order to better understand the drivers of generators' cost of capital, the Commission carried out its own analysis for the draft rule determination and found that:

- equity betas of generators and generation asset developers are relatively low compared to other energy businesses and the financial market in general
- the cost of debt for BBB rated non-financial debt has been falling in Australia, resulting in a lower cost of capital generally implying that any relative decrease in the credit rating

78 Minter Ellison, *Australian renewable energy investment trends and outlook*, June 2019.

79 For example, submissions to the consultation paper: CEIG, PARF, p. 5.

would have a relatively lesser impact on the cost of debt compared to a scenario where the cost of debt is stable or rising

- a reduction in the gearing level (so that there is more equity funds invested compared to debt) will increase the cost of capital but overall, the cost of capital for renewable generation investments seems to be relatively low compared to the market
- overseas investors have, as recently as September 2019, committed substantial funds to invest in Australian generation assets.

**Impact of MLFs on cost of equity**

On the first of the points noted above, the Commission noted that on the equity-side, investors have expressed concerns that the decline in MLFs may impact on their ability to provide equity financing to Australian generation investment.

One of the main drivers of investors' returns is the equity beta. The equity beta signifies the systematic risk of an investment — the risk that cannot be diversified away by holding a portfolio of assets. All other things being equal, the riskier the investment compared to the overall market, the higher the equity beta and the required return.

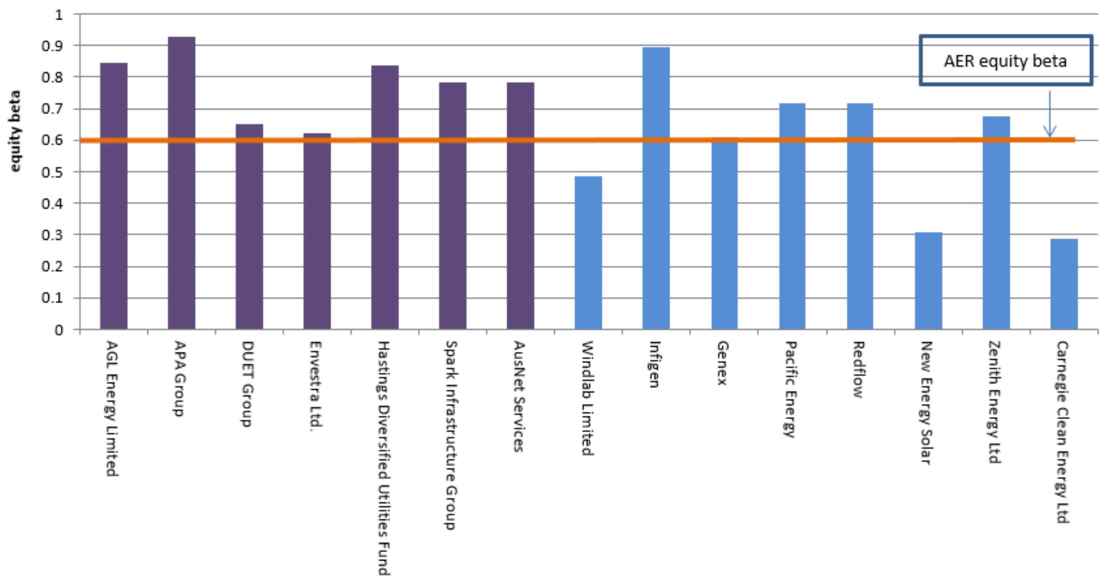
In addition, the gearing ratio of an investment also impacts on the equity beta. All other things being equal, including the level of systematic risk, the higher the gearing level of an investment (that is, the more equity funds are used compared to debt), the higher the equity beta.

These relationships[80] imply that less debt financing for an investment would result in an increase in the cost of equity caused by an increase in the equity beta.

Figure 3.4 was included in the draft rule determination. It compared the equity betas (levered) of Australian energy companies; the AER's equity beta for regulated electricity distribution and transmission service providers and gas pipeline service providers; and the equity betas of developers, investors and owners of generation assets. The graph in Figure 3.4 shows that some of the generation assets or renewable energy equity betas (shown as blue bars) are lower than what the AER uses to estimate the cost of capital for regulated service providers. The equity betas for renewable generation assets are also similar or lower than most of the comparators set that the AER has used to estimate its equity beta range (purple bars). For example, Windlab (a member of the Clean Energy Investor Group) has an equity beta of 0.5, which is lower than the equity beta the AER uses (0.6) and lower than any equity beta in the set of comparators the AER used to estimate its equity beta range. Others, such as Infigen are higher than the AER's equity beta but lower than the market beta of one implying that they are less risky than the market.

80 The relationship between the levered equity beta, systematic risk and gearing. The unlevered equity beta (or asset beta) only takes into account systematic risk.

## Figure 3.4: Equity beta comparison




Source: Bloomberg
Note: The graph shows equity betas for publicly traded energy business and developers. The orange line represents the equity beta the AER is using in its determinations for electricity and gas service providers. A gearing level of 60% is used by the AER for its levered equity beta estimate.

### Impact of MLFs on cost of debt

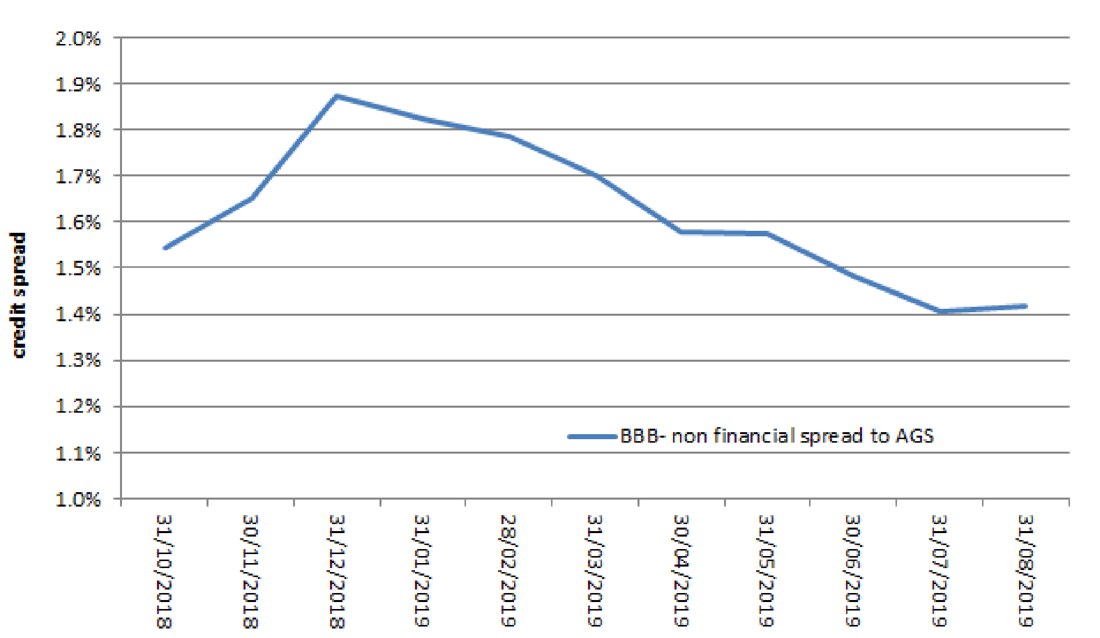
The draft rule determination also discussed the impact of loss factors on the cost of debt for generation asset owners. It noted that on the debt-side, investors expressed concern that a decline in MLFs may trigger debt covenants.[81] This in turn could reduce the ability of those investors to refinance debt, resulting in a higher credit spread and lower gearing of investments.

However, the Commission noted that the nominal risk free rate (as measured by 10-year nominal Australian Government bonds and credit spreads) has fallen significantly over the last 12 months or so. Figure 3.5 shows the trend in credit spreads for BBB rated non-financial debt, as measured by the RBA. It indicates that the timing of obtaining finance or refinancing can impact significantly on the cost of debt. For example, credit spreads for BBB rated non-financial debt was 1.87 per cent over the nominal risk free rate in December 2018, and 1.41 per cent in July 2019. Over the same period, the nominal risk free rate declined from 2.13 per cent in December 2018 to 1.2 percent in July 2019. Consequently, the cost of debt for a BBB rated non-financial investment would have been 4.0 per cent in December 2018 and 2.6 per cent in July 2019 based on the data we have gathered from the RBA and Bloomberg. The Commission noted that this fall in the cost of debt would have an impact on

81 A debt covenant is an agreement between a company and a creditor that sets out limits or thresholds for certain financial ratios that the company may not breach.

the refinancing of assets. For example, an asset originally financed using BBB rated debt would see a significant fall in the cost of debt all other things being equal. Consequently, if the debt of a generation asset gets downgraded due to MLF risk, it is likely that the relative effect on the cost of debt would be dampened because of the general fall in the risk free rate and credit spreads.

**Figure 3.5: BBB — non financial spread to risk free rate**



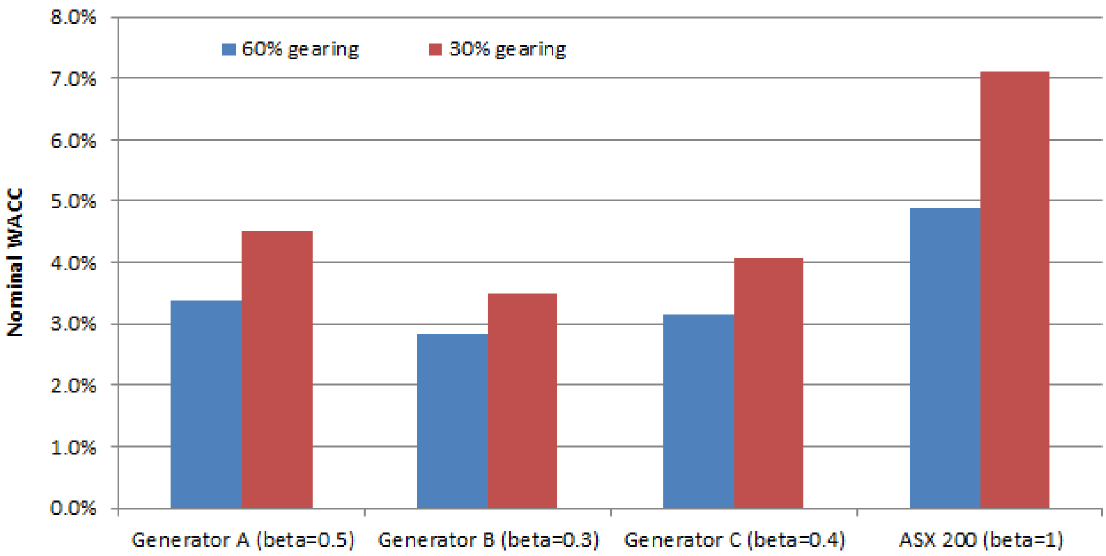

Source: RBA
Note: The graph shows the trend in BBB rated non-financial credit spreads (to the Australian Government securities - AGS) between October 2018 and August 2019.

The Commission commented that if debt covenants were triggered, this would be likely to result in an increase in the cost of debt financing and a reduction in the gearing ratio as lenders reduce their exposure to the asset. All other things being equal, this would result in an increase in the WACC. While a change to an average loss factor methodology may delay this from occurring, it would be likely to only shift the problem into the future, rather than resolving it. The Commission also noted that an increase in the WACC would also allocate risks efficiently, that is to the asset owner rather than to consumers and other generators as could be the case under an average loss factor methodology

**Impact of MLFs on the gearing ratio**

In the draft rule determination, the Commission noted that if lower MLFs result in a reduction in gearing, generators would require more equity capital, which all other things being equal, is more expensive than debt capital. Figure 3.6 shows that a reduction in the gearing ratio from 60 percent to 30 percent would result in an increase in the cost of capital (WACC). However, given that equity betas of generators seem to be relatively low compared to the market, the Commission observed that the WACC for generators would still be considerably lower than that of the market after a change in the gearing ratio.

**Figure 3.6: WACC and gearing**




Source: AEMC
Note: The graph shows the WACC for generators with different equity betas (levered equity betas) and the market for gearing levels of 60 and 30 percent. Equity betas for stylised generators A, B and C have been chosen with reference to equity betas of traded energy generation and generation developer businesses obtained from Bloomberg in October 2019.

In summary, the draft rule determination noted that while stakeholders expressed concern about refinancing the debt of existing generation assets that are experiencing declining loss factors, it was not clear if this was a temporary issue or whether it was impacting on all assets in the generation sector. The Commission considered that the market would provide financing to the most efficient investments at the best price. In terms of equity investment, it noted that:

- The equity betas of generation investments are lower than the market beta of one, and some are lower than the AER equity beta for distribution and transmission service providers and gas pipeline service providers.
- Some investment risk mentioned by stakeholders in submissions can be diversified away by holding a diversified portfolio of assets. For example, stakeholders holding a larger portfolio of generation assets generally submitted that they believe that in the absence of dynamic pricing, MLFs are the most efficient methodology to estimate loss factors and that portfolio diversification was a way to hedge MLF risk.

### 3.3.6 Other relevant work

The Commission considered in the draft rule determination that the most efficient solution to the problems identified above are the introduction of dynamic marginal pricing with financial risk management products. This would provide the most efficient locational signals, allow generators to hedge loss factor variability and in the long-run address network congestion issues. While dynamic pricing with financial risk management products can not be immediately implemented in the NEM, the Commission considered that MLFs provide the most efficient, implementable solution available at present.

A number of stakeholders submitted to the consultation paper that any changes to the transmission loss factor framework should be made holistically with broader market reform work. AEMO submitted that:[82]

> ...any major change to the transmission loss factor framework must be considered with the broader market reform work underway. This should include the AEMC's work on COGATI, transparency of new projects rule change, and the ESB's work on post-2025 NEM market design.

The AER similarly submitted that "it is more desirable to make improvements through the other, more holistic, review and reform processes already in train, than through these isolated proposals".[83] The submissions by AEMO and the AER were echoed by a number of other stakeholders.[84]

Lighthouse Infrastructure submitted that:

> ...the trend toward higher system losses must be addressed by planning-led coordination of generation and transmission development. Market design improvements will not compensate for a sub-optimal underlying physical system.Ultimately unnecessary losses will increase the cost of electricity for consumers.

While noting these reform projects, some stakeholders submitted that the cost of retaining the status quo was too high and that the related projects will take too long to implement.[85] Canadian Solar considered that although any holistic design changes to MLF framework are best captured under the COGATI review, there is necessity for change through this rule change through transitional arrangements.[86] However, the Commission noted that addressing the identified problems of variability and unpredictably of MLFs and increased physical electrical losses is best done through a broader more holistic market reform.

### Transparency of new projects

The Commission initiated a rule change process on 18 April 2019, consolidating three rule change requests that were seeking to increase transparency of new generators connecting to the transmission network:

82 AEMO submission to the consultation paper, p. 1.

83 AER submission to the consultation paper, p. 2.

84 See also submissions to the consultation paper: Canadian Solar, p. 1; Stanwell, p. 1; CS Energy, attachment; Hydro Tasmania, p.2; EUAA, p. 1; Mondo, p. 2.

85 Submissions to the consultation paper: CEC supplementary, Baringa report, p. 8; PARF, p. 5.

86 Canadian Solar submission to the consultation paper, p. 2.

- the AEC sought to improve information provision in the NEM by codifying AEMO's generation information page in the NER, reforming the intending participant category and clarifying the rules around disclosing confidential information
- AEMO sought to allow developers that sell a grid scale resource prior to connection to register as intending participants, giving these developers access to important system data
- Energy Networks Australia sought to allow TNSPs to publish certain project information they have received from connection applicants.

The Commission published a final rule on the 24 October 2019 that will provide market participants better and more up-to-date information about what new generation projects are in the pipeline, which can help businesses make better investment decisions, such as where to locate.[87]

The Commission's final rule:

- facilitates greater access to relevant system information for developers that sell grid-scale assets prior to connection, while recognising that certain types of developers can already access this information by registering as intending participants
- codifies AEMO's generation information page in the NER, which is an information resource that provides regularly updated data on existing and proposed generation connections to the national grid
- requires TNSPs to share key connection information about new generation projects with AEMO, which AEMO must then publish on its generation information page.

The effect of these amendments is to provide better and more up-to-date information about what generation projects are in the pipeline, making it easier and quicker for developers to assess the viability of proposed projects, as the energy market transitions. As a result, market participants will be better informed, and therefore able to make more efficient decisions on where to invest in new generation, which could ultimately benefit consumers by promoting reliable supply at lower costs.

The Transparency of new projects rule change is closely related to the problems associated with the rule change requests from Adani Renewables. Submissions and stakeholder comments regarding recent year-on-year lowering of MLFs suggested that more information about forthcoming generation projects would allow investors to better forecast potential changes to MLFs that may arise.

### COGATI review

The differences between transmission and generation decision-making processes are manifesting in a range of issues currently being experienced by investors, which includes MLFs. The Commission considers that changes to the transmission frameworks are needed so that the regulatory framework evolves to match the transition in the NEM. Transmission

87 AEMC, *Transparency of new projects*, rule determination, 24 October 2019.

access reform is vital in order for the NEM to effectively evolve and transition to a lower emissions power sector, whatever this future may look like.

The Commission published a discussion paper for the COGATI review in October 2019. This set out further detail on its proposed approach to reforming the current access framework for transmission networks across the NEM which involves changing three inter-related aspects of the current transmission access framework.

Reforms to transmission network access arrangements are likely to have significant implications for the appropriate approach to calculating loss factors. For example, in some overseas markets where there are locational marginal prices, MLFs are calculated dynamically at each location in real time. As a result, reforms to the loss factor framework will be considered in the COGATI review as part of the development of reforms to the access arrangements for transmission networks. The Commission is working with the ESB, AER, AEMO, as well as interested stakeholders, to progress the COGATI review. It will continue to consider the interactions between Adani Renewables' rule change requests and the COGATI review throughout both of these processes.

#### ESB post 2025 market design

The COAG Energy Council tasked the ESB with developing advice on a long-term, fit-for-purpose market framework to support reliability that could apply from the mid-2020s. The ESB recently released its market design issues paper. This paper provides advice on a long-term, fit-for-purpose market framework to support reliability, modifying the NEM as necessary to meet the needs of future diverse sources of non-dispatchable generation and flexible resources including demand side response, storage and distributed energy resource participation.[88]

The ESB post 2025 project relates to MLFs as it addresses a number of the issues which the Commission has identified above in this chapter. The ESB issues paper discusses five key challenges that will be material to the market design in 2025:[89]

- driving innovation to benefit the consumer
- investment signals to ensure reliability
- integration of distributed energy resources into the electricity market
- system security services and resilience
- integration of variable renewable energy into the power system.

## 3.4 Pre-final rule determination hearing

In presenting to the Commission at the pre-final rule determination hearing, Innogy submitted a research paper and noted that paper articulates that the NEM has a strong

88 ESB website: http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-issues-paper-%E2%80%93-september-2019

89 ESB, *Post 2025 Market Design*, Issues Paper, September 2019, p. 3.

locational signal but the signal is less effective because of a lack of credibility caused by volatility and a lack of transparency.[90]

QIC also presented on what is causing concern in the investment community, stating:[91]

> Putting aside all the - the political uncertainty, which has also had an adverse impact in relation to the availability of capital and also the cost of capital in the energy sector there have been significant developments in the regulatory environment which, in our view has increased investor uncertainty...

Following that statement, QIC stated that "in particular, the recent unprecedented variability that we've seen in marginal loss factors has created an environment with an unacceptably high level of risk."[92]

Infigen commented that while it agreed that MLFs are a real issue, this shouldn't override the underlying laws of physics and economics to solve the problem. Infigen submitted that "This is really an asymmetric information and transparency issue, not a fundamental design problem".[93]

Infigen further stated that:[94]

> The key problem and cause, as we see it, is that there has been a lack of transparency and guiding information available to market participants including the potential swings in MLFs and their sensitivity to new generation in the neighbouring areas or beyond. So there is clearly things we need to do to improve that transparency.

Infigen concluded by stating:[95]

> MLFs are clearly a part of our decision project, but it’s only a part and it’s certainly not the biggest challenge that we see to investment and, okay, to be clear, there are challenges. The connection delays for new projects, system security, proposals to mandate the free provision of services like mandatory primary frequency control and all the various missing markets that lead to unplanned interventions, whether by AEMO or by governments, and it’s those markets and those issues that we really should be directing our attention if we want to ensure that investment continues smoothly into the future.

## 3.5 Stakeholder views on the draft rule determination

Some stakeholder submissions responded to the Commission's analysis of what is causing the year-on-year changes in MLF values.

90 AEMC, transcript of pre-final rule determination hearing, p. 10.
91 AEMC, transcript of the pre-final rule determination hearing, p. 14.
92 AEMC, transcript of the pre-final rule determination hearing, p. 13.
93 AEMC, transcript of the pre-final determination hearing, p. 16.
94 AEMC, transcript of the pre-final determination hearing, p. 17.
95 AEMC, transcript of the pre-final determination hearing, p. 19.

Infigen submitted that "this is an asymmetric information and transparency issue, rather than a fundamental design problem, and, we believe that the AEMC should not seek to socialise losses.[96] Origin submitted on the same point and reiterated its submission to the consultation paper:[97]

> ...that the lack of transparency around generation projects in the pipeline could be leading to sub-optimal locational decisions.

Origin did note that this has been somewhat addressed through the Transparency of new projects rule change.[98]

A number of submissions agreed with the Commission's characterisation of what is causing the variability in MLFS year-on-year. Snowy Hydro agreed with the Commission's identification of what is causing the yearly challenges that certain participants are having with MLFs.[99] The AER reiterated the Commission's analysis and submitted that:[100]

> Changes in MLFs reflect changes in actual physical electrical losses in the transmission system as new generation connects. As the AEMC and other stakeholders have accurately highlighted, the recent volatility of MLFs is a result of the current transition of the NEM's generation profile:
>
> - The NEM is forecasted to replace most of its current generation stock by 2040.
> - The profile of new generation connecting in the NEM is moving towards a larger number of relatively small and geographically dispersed generators.
> - These generators are connecting in remote areas of the network to locate near fuel sources (e.g. where it is windy or sunny), which lack transmission capacity or which are a significant distance from load (in turn, contributing to high losses).
> - New generation is able to connect at a relatively rapid rate due to the speed of construction with which new generation assets can be built. This means that changes to MLFs occur more frequently as the result of new generation rapidly connecting to the network.
> - The new generation plants often have correlated, rather than offsetting, dispatch characteristics, which can contribute to congestion and, in turn, losses.

The ACCC also agreed with the Commission's observation that "as generation technologies continue to evolve and numerous small and geographically dispersed generators continue to connect to the NEM, the system has experienced more volatility in MLFs."[101] The AER further stated that "recent volatility of MLFs is a result of the electricity sector's current transition."[102]

96 infigen submission to the draft determination, p. 1.
97 Origin submission to the draft determination, p. 2.
98 Origin submission to the draft determination, p. 2.
99 SnowyHydro submission to the draft determination, p. 1.
100 AER submission to the draft determination, p. 1.
101 ACCC submission to the draft determination, p. 2.
102 AER submission to the draft determination, p. 2.

ENA also supported the draft rule determination, noting "that the recent volatility in marginal loss factors reflect a broader set of generation and transmission issues which are beyond the scope of the transmission loss facts rule change process."[103]

In considering the root of the issue with MLF variability, some stakeholders commented on how best to address these broader issues. Origin suggested that if addressing the problem warrants a deeper exploration of the underlying causes, then the Commission should do so through COGATI review.[104] The AER similarly submitted that:[105]

> We consider the CoGaTI review is the best process for the AEMC to holistically consider the issues contributing to loss factor volatility and to formulate long-term access reform that will promote efficient and coordinated generation and transmission investment and allow participants to manage transmission-related risk.

Where stakeholders submitted on the impact that recent MLF values are having on investment and cost of capital, this has been summarised and addressed in Chapter 5.

## 3.6 Final rule determination assessment

Having considered all stakeholder submissions, as well as other information presented to it throughout the rule change process, the Commission is satisfied that it has correctly identified the underlying causes in relation to MLF volatility, unpredictability and the associated costs of year-on-year changes.

The Commission's view is consistent with its analysis set out in the draft rule determination; there are various factors driving changes in MLF values. The Commission does not agree with the proponent's rationale for the rule change requests that the current MLF calculation methodology is either:

- out-dated[106] or
- inaccurate[107]

In submissions to the draft rule determination, a number of stakeholders consistently identified two key factors as causing the variability in MLF values. These were:

1. asymmetric information and transparency issue in regard to generation entering the NEM[108]
2. the current transformation of generation in the NEM.[109]

103 ENA submission to the draft determination, p. 2.
104 Origin submission to the draft determination, p. 2.
105 AER submission to the draft determination, p. 2
106 Adani Renewables, rule change request, 27 November 2018, covering letter.
107 Adani Renewables, rule change request, 27 November 2018, p. 3; Adani Renewables, rule change request, 5 February 2019, p. 3.
108 Submissions to the draft determination: infigen, p. 1; Origin, p. 2.
109 Submissions to the draft determination: SnowyHydro, p. 1; AER, pp. 1-2; ACCC, p. 2; ENA, p. 2.

Related to the first of these, the Commission notes that a number of stakeholders considered that the new Transparency of new projects rule will address concerns about the visibility of new generation assets entering the NEM.[110]

On the second issue, some stakeholders agreed with the Commission that the broader issues arising from the transformation in generation in the NEM are best addressed through a more holistic approach.[111]

However, this view was not held by all stakeholders. In particular, the CEIG submitted that:[112]

> Deferring the required reform of the loss factor framework to the incomplete and highly uncertain COGATI process is an unnecessary risk given the "no regrets" nature of the proposed ALF framework...

The Commission considers that in order to more fully address stakeholders concerns with regard to MLF variability, broader issues need to be solved that are outside the scope of this rule change process. The current work by the Commission in its COGATI review as well as work by the ESB (namely, the implementation of the ISP and development of a post-2025 market design for the NEM) are relevant to improving how the NEM operates with a different and changing generation fleet that is needed for the future low carbon emission economy. It remains of the view that the variability of the MLF values and the size of the IRSR are symptoms of the development of increasing investment in new generation assets occurring at the periphery of the electricity grid with little reference to, or coordination with, the investment needs of the relevant transmission infrastructure itself.

110 Submissions to the draft determination: AGL, p. 1; SnowyHydro, p. 2; Origin, p. 2; AER, p. 2; ENA, p. 1.

111 Submission to the draft determination: ACCC, p. 2; Origin, p. 2; AER, p. 2; SnowyHydro, p. 2; AEC, p. 2; AGL, p. 2; ENA, p. 2; TasNetworks, p. 2; Stanwell, p. 2; PIAC, p. 1; AEMO, p. 1.

112 CEIG submission to the draft determination, p. 6. This was replicated by CEIG member submissions to the draft determination: ESCO, p. 5; Windlab, p. 7; Foresight group, p. 7; Innogy, p. 7; PARF, p. 4.

# 4 INTRA-REGIONAL SETTLEMENT RESIDUES

This chapter outlines the rule change request related to IRSRs, and its rationale, lodged by Adani Renewables.[113] It provides a summary of stakeholder submissions to both the consultation paper and draft rule determination in relation to the proposed reallocation of IRSR. Furthermore, it provides the Commission's analysis of the request and stakeholder submissions and its reasoning for the final rule determination.

## 4.1 What are intra-regional settlement residues?

In the NEM the payments made by consumers of electricity (customers) do not match, and generally exceed, payments made to providers of electricity (generators). This occurs for a number of reasons including:

- Price separations between adjacent regions due to interconnector transfer limits.[114]
- Approximations in the representation of inter-regional loss factor equations.
- The use of intra-regional loss factors that are marginal loss factors.[115]

The inter-regional settlement residues are comprised of the residues due to price separation and the impact of inter-regional losses which are calculated for each interconnector and trading interval. Market participants can access the inter-regional settlements residues through an auction process and this can assist them to hedge their spot market exposure, especially for inter-regional trading.[116]

The remainder of the residues that accrue within a given region are the intra-regional settlement residues (IRSR).[117] As noted above, this tends to be positive but can be negative.

The IRSR are paid to (or recovered from) the TNSP for the associated region and used to decrease (or increase) TUOS charges. As IRSR is usually positive, this effectively results in the IRSR being returned to customers, as only customers (not generators) currently pay TUOS charges and consequently fund investment in transmission infrastructure.

In addition, the IRSR are returned to customers on a postage stamp basis as part of the non-locational component of TNSP revenue.[118] As a result, there is no link between the accrual of IRSR and the manner in which it is distributed to customers. This has the advantage that it minimises the impact on real-time bidding behaviour of market participants (that is, bids from

113 The Commission has consolidated this rule change with the second rule change submitted by Adani Renewables under s. 93 of the NEL to enable it to address the overlapping issues arising from these requests.

114 When the flow on an interconnector is limited by a network constraint the electricity flow is generally from the lower priced region to the higher priced region. This means that electricity is paid for in the exporting region at a lower price than that paid by customers in the importing region, resulting in a settlement residue.

115 Marginal intra-regional loss factors are used in the NEM as this produces efficient signals for dispatch and longer-term investment. However, the use of marginal loss factors tends to recover more revenue from consumers than is paid to generators, contributing to settlement residues. A theoretical description of marginal loss factors is provided in AEMO, *Treatment of loss factors in the national electricity market*, available on AEMO's website.

116 Details of the calculation of inter-regional settlements residues and the auction process are available on the AEMO website.

117 Clause 3.6.5(a)(3) of the NER.

118 Clauses 6A.23.3(e) and 6A.23.4(e) of the NER.

market loads). Consequently, the redistribution of IRSR does not distort the economic dispatch of the market.

## 4.2 Adani Renewables' views

On 27 November 2018, Adani Renewables submitted a rule change request to reallocate the IRSR to generators and market customers equally.[119]

Adani Renewables outlined three issues with the current approach and a fourth point articulating what it considered the result of a change would be:[120]

1. The current approach to the calculation and application of MLFs gives rise to loss factors that are approximations of actuals.
2. To the extent that high IRSRs represent cumulative error between forecast and actual losses, efficient dispatch of generation is undermined (through changing dispatch order and interfering with investment signalling).
3. Where MLFs are inaccurate, they can give rise to IRSRs. The existing approach of allocating these residues to customers via postage stamp TUOS then worsens the impact of any inaccuracy in loss factors, by funnelling this money away from generators.
4. Were IRSRs handed back to generators, some of the distortionary impact would be reduced.

Further, Adani Renewables stated that the current rules relating to transmission loss factors are resulting in high inaccuracies, which distorts the market through inefficiencies in operational and investment decision-making.[121] It considered that there are two factors within the NER causing these inefficiencies:[122]

1. Currently the generators do not receive any allocation of Intra-Regional Settlements Residue (IRSRs) that accrue due to MLF inaccuracies. IRSRs are returned only to one segment of market customers. A rule change to facilitate a reallocation of IRSRs to include generators will harbour savings that can be passed on to all market customers.
2. The inaccuracy in forecasting MLF for the following year/s results in generators assuming an artificially increased bid price as a result of an incorrect MLF. Hence generators are subject to an increased risk of not being dispatched, resulting in an increased cost of generation for all market customers.

The rationale for the reallocation of the IRSR provided by Adani Renewables is that it would result in "an improved effective MLF (less losses) for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to

119 Adani Renewables, rule change request, 27 November 2018, covering letter.

120 Adani Renewables, rule change request, 27 November 2018, p. 7.

121 Adani Renewables, rule change request, 27 November 2018, covering letter.

122 Adani Renewables, rule change request, 27 November 2018, covering letter.

market customers".[123] Specifically, it stated that redistributing half of the IRSR funds to generators would:[124]

> …correct for any inaccuracies associated with the MLFs, and associated inefficiencies caused by these inaccuracies. While this change to the reallocation process will not directly address the cause of inefficiencies caused by inaccurate MLFs, it may go some way to reducing the impacts this inaccuracy has on the investment and operational efficiency of the NEM.

Adani Renewables summarised its rule change request by stating:[125]

> Adani Renewables proposes a rule change so that the process for the allocation of IRSRs be revised to include generation connection points and not only the network users who are subject to non-locational prescribed TUOS charges. The result of this rule change will be lower effective MLFs for generators that have been subject to inaccuracies and therefore more competitive generation bidding, resulting in lower prices to market customers.

## 4.3 Stakeholder views on the consultation paper

Stakeholder submissions to the consultation paper generally focused on whether there should be a change in the way transmission loss factors are calculated; a number of stakeholders did not provide any comment in relation to the request to reallocate the IRSR. Additionally, no stakeholders provided direct comment that the current allocation of IRSR is problematic and will have a material impact on the long-term interest of consumers.

### 4.3.1 Allocation of IRSR

The ACT Government Department of Environment, Planning and Sustainable Development (EPSDD) stated that it did not consider that the current IRSR arrangements "necessarily represents a problem".[126]

Other stakeholders simply supported the proposed reallocation of part of the IRSR to generators without outlining specific reasons or identifying that the current IRSR arrangements are problematic.[127]

Although not explicit, it was apparent through the submissions that stakeholders who did address the proposed reallocation of IRSR did not necessarily consider the current distribution of the IRSR to customers only as problematic. Stakeholders who supported a reallocation of the IRSR were more focused on the accrual of the IRSR resulting from over-

123 Adani Renewables, rule change request, 27 November 2018, covering letter.

124 Adani Renewables, rule change request, 27 November 2018, pp. 7-8.

125 Adani Renewables, rule change request, 27 November 2018, p. 3.

126 ESPDD submission to the consultation paper, p. 3.

127 Submissions to the consultation paper: Enel Green Power, p. 1; Engie, p. 2; Canadian Solar, p. 2; ERM Power, p. 2; Investor Group, p. 13.

recovery of losses stemming from the perceived inaccuracies in the MLF calculation methodology.

Meridian Energy Australia and Powershop Australia (together, MEA Group) supported the proponent's request and suggested that a reallocation of IRSR would address the problem of inaccuracies. A reallocation of the IRSR would act as an effective hedge against a low MLF and mitigate some of the 'cost' associated with inaccurate MLF calculations.[128] The Clean Energy Council (CEC) similarly commented that a reallocation of IRSR "would remove the current systematic IRSR surplus."[129]

There were a number of stakeholders who expressly rejected the claim that the market customers being the sole beneficiary of the IRSR is problematic or an unfair allocation. The Australian Energy Regulator (AER) reflected this sentiment and stated that:[130]

> …it remains appropriate that the IRSR continue to be allocated fully to customers because they bear the majority of costs and risks of transmission investment.

In addition, Intelligent Energy Systems (IES) stated:[131]

> The current distribution of the ISSR (sic) recognises that the IRSR is the outcome of marginal pricing methodology used to account for losses in the network. It aims to reduce the amount to be recovered in network charges generally without destroying the Individual MLF signal. This logic is appropriate for good efficiency. How network charges are distributed is another matter and is one of the subjects of the COGATI review.

Ergon Energy and Energex, and the Central Irrigation Trust (CIT) considered that the rule change request for IRSR itself was problematic and, if adopted would result in TUOS charges increasing and customers paying higher prices.[132] This point was also made by AEMO in its submission.[133] Similar submissions were received from stakeholders who found the premise of reallocating the residue away from customers to generators and customers as problematic:[134]

> …generators do not currently pay TUOS and hence it is inappropriate for them to receive the positive residues…

It was also noted by EnergyAustralia that generators do not pay for the use of the shared transmission network; rather customers pay for all new and ongoing transmission costs

128 MEA Group submission to the consultation paper, p. 2.

129 CEC supplementary submission to the consultation paper, p. 2.

130 AER submission to the consultation paper, p. 2. See similar comments from submissions to the consultation paper: CIT p. 4; Ergon Energy and Energex, p. 2; Energy Networks Australia, p. 4; EnergyAustralia, pp. 8-9.

131 IES submission to the consultation paper, p. 2.

132 Submissions to the consultation paper: CIT, p. 4; Ergon Energy and Energex, p. 2; Energy Networks Australia, p. 4; EnergyAustralia, pp. 8-9.

133 AEMO submission to the consultation paper, p. 6.

134 Energy Networks Australia submission to the consultation paper, p. 4. See also submissions to the consultation paper: AER, p. 2; Ergon Energy and Energex, p. 2; EnergyAustralia, pp. 8-9.

through TUOS charges. It further stated that Adani Renewables' solution of returning part of the IRSR to generators would not address the root cause of the problem.[135]

### 4.3.2 Calculation of IRSR

First Solar agreed with Adani Renewables and suggested that as there is an over-recovery resulting from inaccuracies and that this should be rectified through part of the IRSR being reallocated to generators. First Solar submitted that this would be a fair reflection of a generator's contribution to transmission losses.[136]

AEMO noted that the proposal to reallocate IRSR would increase TUOS charges, and therefore considered that the benefits of the proposal must be assessed against the achievement of the NEO. AEMO also highlighted that South Australia's IRSR currently and predominately materialises in a negative amount.[137] AEMO stated that if the Commission reallocated the IRSR, generators in South Australia would consequently receive a bill, rather than a positive allocation.

AEMO also considered the impact on the IRSR if the Commission was to adopt an ALF calculation methodology. It stated:[138]

> ...a move to average loss factors would see a reduction in revenue collected from Market Customers, which may result in significant under-recovery and negative inter-regional settlement residue (IRSR) under some conditions. In the long run, and under circumstances where average loss factors could be calculated exactly, average loss factors would be expected to result in a zero average IRSR as prices would no longer reflect the marginal value of losses. However, in practice this may result in an increased risk of negative IRSR across the NEM and potentially lead to settlement periods when insufficient revenue is recovered from customers to pay generators.
>
> While AEMO acknowledges that average loss factors should result in higher pool payments which could offset the impact of negative residues, AEMO suggests that the risk of increased negative IRSR is considered by the Commission as part of its assessment of this aspect of the rule change request.

## 4.4 Draft rule determination

In the draft rule determination, the Commission considered whether a change to the allocation of the IRSR would, or would be likely to, contribute to the achievement of the NEO. Its analysis addressed Adani Renewables' rationale for the rule change and stakeholder submissions.

The Commission did not agree with the proponent's characterisation that the way MLFs are calculated results in high inaccuracies in MLF values which create a high and undesirable

135 EnergyAustralia submission to the consultation paper, pp. 8-9.
136 First Solar submission to the consultation paper, p. 3.
137 AEMO submission to the consultation paper, p. 6.
138 AEMO submission to the consultation paper, p. 6.

positive accrual of IRSR. In addition, it did not agree that it is appropriate for the IRSR to be shared between customers and generators.

In forming this conclusion, there are two key aspects which the Commission considered:

- settlement residues arise due to the marginal pricing framework
- that there is a need to allocate these residues and that they are most appropriately returned to customers to offset TUOS charges.

### 4.4.1 Marginal pricing framework

Marginal loss factors represent the additional losses that occur between a generator dispatching electricity and the delivery of that electricity to customers at the regional reference node for one additional unit (1 MW) of electricity. Losses increase with the square of the power flowing along the line. This means that marginal loss factors (the losses caused by an additional unit of flow along the line) are higher than the actual losses incurred. Thought of another way, the losses for the next unit of power flowing across the line are higher than the previous unit of power flowing across the line.

Marginal loss factors (as opposed to actual loss factors) send an appropriate price signal to market participants in both dispatch and investment timescales.[139]

The use of marginal loss factors generally results in an over recovery of funds because generators are paid for electricity generated on a marginal basis. An IRSR for a jurisdiction resulting in a surplus amount is not due to "inaccuracies". Rather, it is a necessary and natural consequence of the appropriate decision to use the marginal pricing mechanism to calculate loss factors. The Commission therefore stated in the draft rule determination that it did not agree with Adani Renewables' characterisation that the calculation methodology of loss factors is itself inaccurate and results in high inaccuracies in the form of undesirable and significant IRSR.

It also noted that including generators as recipients of IRSR would mean that generators are no longer being settled based on MLFs (assuming that the IRSR would be distributed in correlation with generator output rather than being allocated across generators in some other way). This would result in generators' revenues reflecting MLFs plus the IRSR amount (irrespective of being a negative or positive value). This would represent a move away from the principle of marginal pricing, and as a result, be an economically inefficient arrangement.

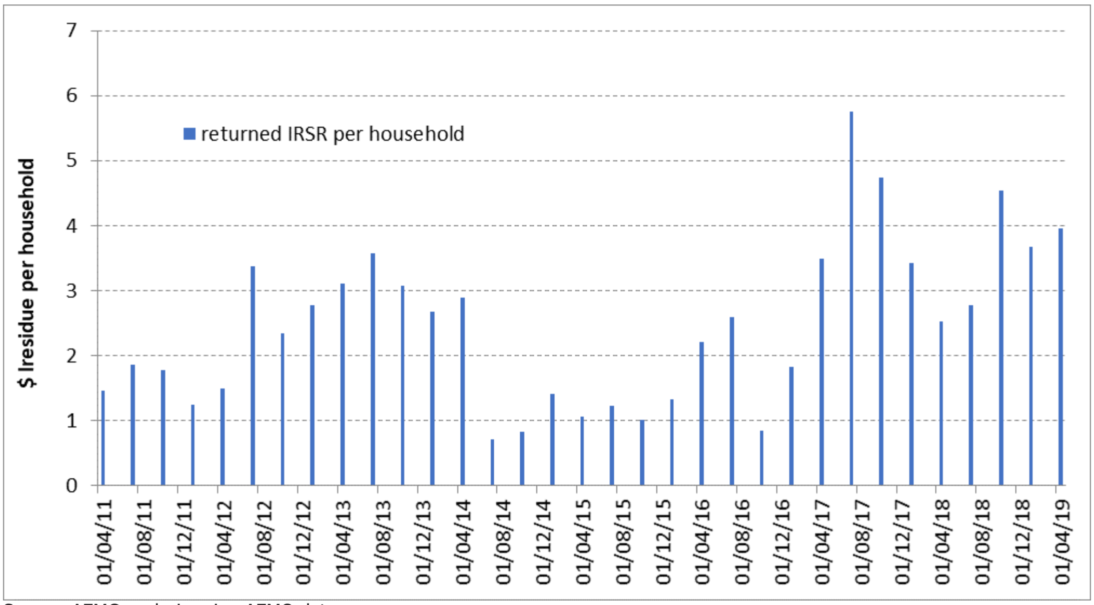
### 4.4.2 Consumers and the IRSR

Customers pay for transmission infrastructure through TUOS charges. This flows through to the electricity bills of end-use consumers. TNSPs who receive the IRSR in circumstances where there is a surplus are required to apply that directly to TUOS charges.[140] A positive IRSR therefore results in lower electricity bills, as illustrated in Figure 4.1 below.

139 This is discussed in more detail in Chapter 5.

140 Clause 3.6.5(a)(6) of the NER.

**Figure 4.1: Quarterly IRSR returned to customer per household, NSW**




Source: AEMC analysis using AEMO data

The draft rule determination noted that the existence of a settlements residue is a natural consequence of using a marginal pricing mechanism for loss factors. As customers pay for the transmission infrastructure being used, it is appropriate that customers' transmission costs are reduced where funds are available.

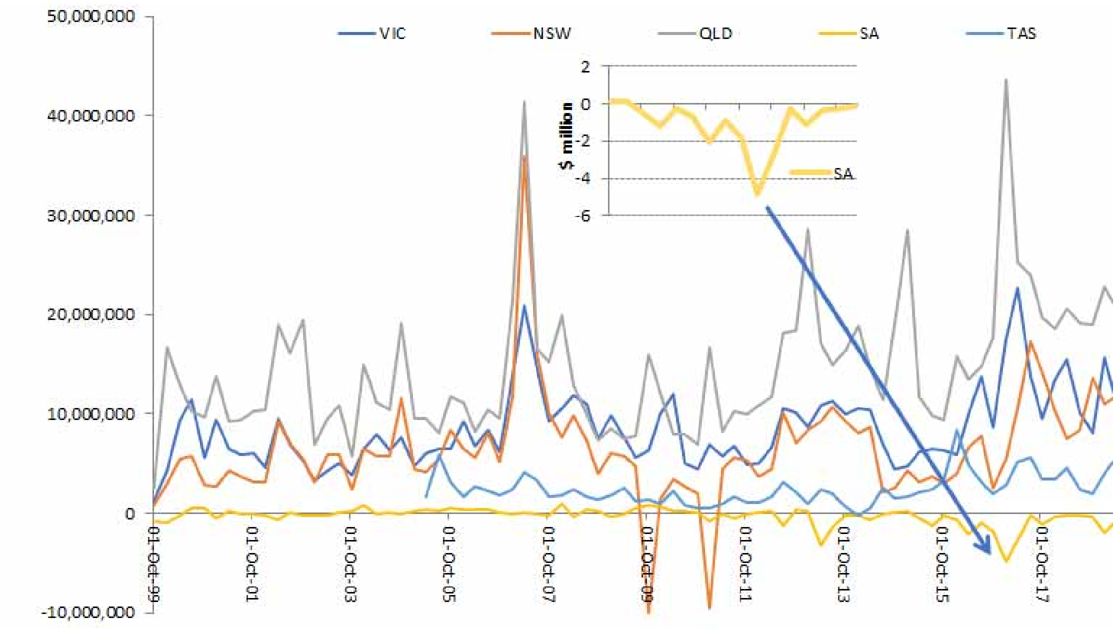
In its rule change request, Adani Renewables suggested that revising the allocation of IRSRs to include generation connection points would lower prices to market customers.[141] However, the draft rule determination noted that the amount to which wholesale energy prices might be reduced would be uncertain and, in any event, would be unlikely to benefit customers to a greater extent than the existing arrangements. The current arrangements already directly reduce customers' electricity bills in circumstances of positive IRSR as specified by the NER. The Commission considered in its draft rule determination that a departure from this may result in a less efficient arrangement that may not as clearly or directly benefit customers.

While the use of MLFs tends to result in a positive accrued IRSR, under certain conditions the IRSR can be negative. The NER currently states that where the IRSR results in a negative pool, TNSPs are liable to reimburse that to AEMO.[142] Negative IRSR may occur in instances where there is a high spot price in combination with high temperatures and/or high load. This may lead to higher electrical losses in the system than the forecast annual MLFs accounted for, resulting in AEMO collecting less revenue than what it must pay generators. Figure 4.2 below illustrates instances of negative IRSR occurring.

141 Adani Renewables, rule change request, 27 November 2018, p. 3.

142 Clause 3.6.5(a)(4)(i) of the NER.

**Figure 4.2: Annual IRSR jurisdictions amounts from 1999-2017**




Source: AEMO.
Note: This data has been aggregated by AEMO.

Adani Renewables did not consider jurisdictions where circumstances of negative IRSRs occur, as has occurred at times in South Australia. If the Commission was to redistribute the IRSR between generators and customers, it would need to consider a framework where generators were also liable for the payment of IRSR in circumstances of negative amounts arising. This reallocation of the IRSR would likely result in higher electricity prices. This cost would likely be passed on to consumers through generators increasing their spot price.

## 4.5 Pre-final rule determination hearing

Stakeholders did not present any views regarding IRSR to the Commission at the hearing.

## 4.6 Stakeholder views on the draft rule determination

A number of stakeholder submissions did not make any comment in relation to IRSR and the draft rule determination to not reallocate any part of the IRSR to generators. However, several stakeholders did expressly support the draft rule determination.[143]

143 Submissions to the draft determination: ACCC, p. 2; AER, p. 1; Stanwell, p. 1; EnergyAustralia, p. 1; Origin, p. 1; AEMO, p. 1; PIAC, p. 1; Energy Networks Australia, p. 1; TasNetworks, p. 1.

In addition to supporting the draft rule determination, PIAC stated that "to share inter-regional (sic) settlement residues... would not address the underlying cause of recent and expected future MLF volatility".[144]

A number of stakeholders reiterated part of the draft rule determination reasoning for not reallocating part of the IRSR to generators in relation to consumers funding transmission infrastructure. For example, the ACCC stated that "as consumers ultimately pay for transmission infrastructure, it is appropriate that their transmission costs are reduced".[145] Origin also submitted the same point.[146]

The ACCC also agreed with the Commission's analysis that reallocating part of the IRSR from customers to generators would directly impact transmission costs paid by consumers which would have a clear impact on affordability.[147]

Similarly, the AER stated that a reallocation of the IRSR "would not be in the long-term interest of consumers nor better achieve the NEO".[148] Stanwell made similar comments and stated that a reallocation of the IRSR had not been demonstrated to provide a net benefit to consumers.[149]

While no stakeholder submissions disagreed with the draft rule determination in relation to IRSR, the CEC did submit that the Commission should provide deeper analysis into the consumer implications that different TLF methodologies would have on the magnitude of change to the IRSR.[150] This is discussed in Chapter 5.

## 4.7 Final rule determination assessment

Having considered recent stakeholder submissions, the Commission is satisfied that its assessment made in the draft rule determination remains appropriate. That is, a reallocation of any part of the IRSR away from customers would not be in the long-term interest of consumers and would not be likely to contribute to the achievement of the NEO because it would:

- dampen the marginal pricing incentive for generators[151] and therefore negatively impact on the efficient operation of electricity services through distorting bidding behaviour
- result in increased TUOS charges, and likely overall higher costs, for consumers
- place costs on generators in regions where a negative IRSR occurs.

Further, the Commission remains of the view that the proposed reallocation of the IRSR would not address the fundamental cause of the concerns raised by Adani Renewables.

144 PIAC submission to the draft determination, p. 1.
145 ACCC submission to the draft determination, p. 2.
146 Origin submission to the draft determination, p. 1. See also submissions to the draft determination: AGL, p. 2; AEMO, p. 1; AER, p. 2.
147 ACCC submission to the draft determination, pp. 1-2.
148 AER submission to the draft determination, p. 2.
149 Stanwell submission to the draft determination, p. 1.
150 CEC submission to the draft determination, p. 2.
151 If the IRSR was distributed in correlation with generators' output.

## 4.8 Final rule determination

Consistent with its draft rule determination, the Commission has not amended the NER in relation to the distribution of the IRSR.

# 5 LOSS FACTOR METHODOLOGY

This chapter provides the Commission's analysis on whether an average loss factor methodology will, or will be likely to, better contribute to the achievement of the NEO than an MLF methodology. In doing so, it outlines the rule change request, stakeholder views provided during this rule change process as well as the Commission's assessment included in the draft rule determination in relation to the alternative loss factor methodologies.

## 5.1 Adani renewables rule change request

In its rule change request, Adani Renewables proposed that the transmission loss factor methodology should be changed from marginal loss factors to average loss factors. Adani Renewables argued that the existing MLF calculation methodology is out-date and no longer fit-for-purpose. This, in its view, subjects generators to increased risk of not being dispatched, resulting in increased cost of generation to all market customers.[152]

To address these concerns, Adani Renewables proposed that the NEM move from the current forward-looking MLF methodology to an average loss factor methodology. It asserted that this change "from MLFs (with IRSR reallocation to include generators) to an average loss factor methodology will be a further improvement as average loss factors can be calculated at the commencement of each year (rather than a wash up of IRSRs in arrears)".[153] While Adani Renewables noted that requirements for the calculation of intra-regional loss factors are set out in clause 3.6.2 of the NER, it did not propose any specific amendments to these provisions. However, it did argue that AEMO must be required to calculate intra-regional loss factors according to an average loss factor methodology.

Adani Renewables did not provide a preferred methodology of how to calculate the average loss factors.

## 5.2 Stakeholder views on the request

In their submissions to the consultation paper (summarised below), a number of stakeholders agreed with Adani Renewables that the current methodology of using static MLFs for intra-regional losses needs reforming. However, most stakeholders did not agree with Adani Renewables that a change to average loss factors would solve the underlying problem of why loss factors have been declining and becoming more volatile. Some stakeholders agreed that dynamic loss factors should be implemented as part of wider market reforms. There was strong sentiment from stakeholders that more holistic reforms would address the underlying problems of generators building in non-traditional fuel source locations where transmission capacity is insufficient, rather than a change to using average loss factors. Some stakeholders submitted that whilst these more substantial reforms are

152 Adani Renewables, rule change request, 5 February 2019, covering letter.

153 Adani Renewables, rule change request, 5 February 2019, p. 3.

being considered, there are temporary remedies which could provide more investment certainty in the interim.[154]

### 5.2.1 MLFs are economically efficient and provide correct locational signals

The AER submitted that MLFs are consistent with the marginal pricing on which NEM settlement is based. It also noted that using average loss factors would increase the risk that the overall settlement residue balance is negative. The shortfall would be allocated to TNSPs who, in turn, would collect higher TUOS charges from customers.[155]

The AEC did not support a move away from MLFs. It noted that the market requires all supply and demand to be settled at a common clearing price set at their intersection. This means that a two-sided price must reflect the cost of supply, or the elasticity of demand, at the margin at that location and time. It noted that this is consistent with clauses 3.9.2(d) and 3.9.1(a)(6) of the NER.[156]

Energy Networks Australia (ENA) also submitted that any movement away from marginal loss factors to average loss factors would result in an inefficient price signal and redistribute the cost of losses from those responsible to others in the system.[157]

Similarly, Mondo did not support changing to a methodology based on average loss factors as this would deviate from the marginal pricing foundation of the NEM.[158] Mondo submitted that this would "lead to less efficient outcomes in the NEM and therefore fails to meet the requirements of the national electricity objective".[159] Mondo based its preference on its own analysis showing that average losses need to be recognised as being a less accurate representation of losses for the purposes of marginal cost pricing, and therefore the NEM. It referred back to the fundamental economic principle that generally, the marginal cost of supplying one additional unit is greater than the average cost at any given operating point. This marginal value of trade principle is fundamental to ensuring that businesses operating in the market which are paid the clearing price, are able to also recover their fixed costs in the longer term. Mondo considered that if this principle is undone, it could undermine the business model for existing businesses, and weaken investment signals for new entrants.[160]

EnergyAustralia submitted that it is not convinced that there is any evidence to warrant a change from the current MLFs methodology to an ALF or that it is in the best interest of customers or otherwise better contributes to the achievement of the NEO.[161]

In its submission to the consultation paper, SnowyHydro noted that MLFs are a key locational signal in the NEM that provides investors with an incentive to connect new generation close

154 This is discussed in more detail in part 7.1.1.
155 AER submission to the consultation paper, p. 3.
156 AEC submission to the consultation paper, pp. 1-2.
157 ENA submission to the consultation paper, p. 2.
158 Mondo submission to the consultation paper, p. 1.
159 Mondo submission to the consultation paper, p. 8.
160 Mondo submission to the consultation paper, pp. 7-8.
161 EnergyAustralia submission to the consultation paper, p. 1.

to the RRN and leverage efficiencies in the transport of energy across the system.[162] It considered that the proposal to address concerns with the current forward-looking MLF methodology by moving to an average loss factor methodology would not bring NEM-wide benefits and improvements to market participants' circumstances.[163]

AGL submitted that MLFs continue to provide the most efficient methodology for the assessment and application of transmission losses under current market conditions. It considered that this is because of the value it places on the marginal unit of electricity transmitted by individual generators (existing and new) across the network.[164]

Although MUFG Bank submitted that it is indifferent between average and marginal loss factors, it acknowledged that the current methodology is consistent with the clearing price mechanism which is set at the marginal cost of supplying the next unit of generation which, in turn, is required in order to encourage efficient investment and dispatch.[165]

### 5.2.2 ALFs would help address volatility and reductions in MLF values

While a number of stakeholders expressed concern over the proposed change to using average loss factors, others were supportive of Adani Renewables' proposal.

For example, in responding to the consultation paper, the CEC submitted that:[166]

> A higher level of certainty through an ALF approach reduces the risk of the investment, which translates to a lower cost of capital that can ultimately lead to more generation being developed under the same market conditions and therefore lower wholesale electricity prices and lower retail prices for consumers.

Further, the CEC stated that average loss factors would result in less variability in loss factors while still preserving locational signals. It noted that:[167]

> ...the ability for an ALF approach to improve investment certainty is likely to contribute to the NEO as it will improve the provision of information to assist investors and developers in making well-informed decisions on efficiency investment in generation capacity in the NEM.

The CEC's consultant, Baringa, provided modelling results indicating that customers could benefit from lower wholesale electricity prices under average loss and condensed loss factor methodologies.[168]

The CEIG also suggested moving to an average loss factor methodology. The CEIG considered this would deliver the optimal balance between reduced volatility, continued locational price signalling and simplicity of calculation and implementation. The CEIG also

162 SnowyHydro submission to the consultation paper, p. 1.
163 SnowyHydro submission to the consultation paper, p. 2.
164 AGL submission to the consultation paper, p. 2.
165 MUFG Bank submission to the consultation paper, p. 3.
166 CEC supplementary submission to the consultation paper, p. 2.
167 CEC supplementary submission to the consultation paper, p. 2.
168 CEC supplementary submission to the consultation paper, Baringa report, p. 28.

noted that the efficiency impact of moving to average loss factors would be lessened by the fact that MLFs are applied at the RRN and as such are an approximation anyway.[169]

Canadian Solar and Lighthouse Infrastructure also supported a change to average loss factors based on the square root methodology. Lighthouse Infrastructure noted that the trend toward higher system losses must be addressed by planning-led coordination of generation and transmission development. Market design improvements will not compensate for a sub-optimal underlying physical system. Ultimately unnecessary losses will increase the cost of electricity for consumers.[170]

Similarly, PARF focussed on investment of new infrastructure and supported average loss factors. In PARF's view, the ALF approach represents the optimal balance between restoring investor confidence (by making loss factors more stable) and retaining the locational signalling aspect of the existing approach to assist with grid planning objectives.[171] According to PARF, equity investors seek stable project returns, in particular for +20 year assets, and have similar concerns to debt investors regarding MLF revenue risk. PARF considered that the current variability and relative unpredictability of MLFs, if left unchecked, will not only lead to greater amounts of more expensive equity capital required (as lenders decrease total dollar debt available for generation projects), equity investors will also add additional risk premia for existing and new investments in renewable energy. It further noted that, unlike exposures to spot wholesale prices, there are no financial instruments available for debt and equity investors to manage the MLF revenue risk. According to PARF, this MLF risk will inevitably increase the cost of re-contracting offtakes and/or re-financing existing generation assets and increase the cost of constructing new renewable energy generation, leading to higher electricity prices for consumers.[172]

Stakeholders also considered whether the current MLF calculation methodology or a change to an ALF methodology would have a material impact on the long-term interest of consumers. The CEIG submitted that, given there are material risks to current and future generation investment, this will ultimately impact the long-term interests of customers.[173] The CEIG stated:[174]

> From an investor perspective, the above escalating uncertainty has already, and will likely continue to, lead to a material reduction in existing asset values and therefore require an additional risk premium to be applied to any new investments. This additional risk premium could be applied by both equity and debt investors. Unlike risks associated with interest rates and wholesale electricity prices there are no financial instruments or hedges available to investors to hedge MLF risk and as a result investors will be required to make risk adjustments when considering future investment decisions. Potential risk adjustments include a margin of safety applied to

169 CEIG submission to the consultation paper, p. 2.
170 Lighthouse Infrastructure submission to the consultation paper, p. 1.
171 PARF submission to the consultation paper, p. 1.
172 PARF submission to the consultation paper, p. 7.
173 CEIG submission to the consultation paper, p. 1.
174 CEIG submission to the consultation paper, p. 2.

> all MLF forecasts and/or an additional risk premium added to cost of capital. This is expected to increase the cost of capital associated with future projects which will ultimately be passed on to customers through higher wholesale prices. The current MLF framework is therefore increasing the long-term cost to consumers through the future investment required to fund the 54GW of new capacity needed in the NEM by 2040.

The CEIG expanded on this point throughout its submission to the consultation paper and stated that the current methodology inhibits effective revenue forecasts, introduces uncertainty and therefore increases investment risk sequentially resulting in reduced efficiency of electricity supply and increased costs through higher wholesale prices.[175]

PARF also submitted that:[176]

> ...the recent variability and the inherent unpredictability of MLFs has had and will continue to have a material impact on the cost of capital for existing and new generation projects. This will inevitably flow through to electricity prices paid by the consumer and will therefore have a materially adverse effect on their long-term interests.

The CEC highlighted the same point with regard to the cost of capital adversely impacting on consumers:[177]

> Under the current MLF methodology, investors and developers have little certainty about loss factor trajectories, which in turn is introducing a risk premium to the cost of capital. A higher level of certainty through an ALF approach reduces the risk of the investment, which translates to a lower cost of capital that can ultimately lead to more generation being developed under the same market conditions and therefore lower wholesale electricity prices and lower retail prices for consumers.

Lighthouse Infrastructure echoed the same point that "a lower cost of capital will lead to more projects securing funding, ultimately benefiting customers".[178]

### 5.2.3 Changing to ALFs may not benefit the long-term interest of consumers

The Environment, Planning and Sustainability Development Directorate (ESPDD) of the Australian Capital Territory (ACT) government, submitted to the consultation paper that inaccuracies in the current calculation methodology would only have a material impact on the long-term interest of consumers, and "therefore contravene the NEO", if they are both significant in magnitude, and consistent in direction. It commented that it has seen "no evidence that the AEMO is consistently making the same error in its forecasts". [179]

175 CEIG submission to the consultation paper, p. 14.
176 PARF submission to the consultation paper, p. 9.
177 CEC supplementary submission to the consultation paper, covering letter p. 2, also Baringa report, p. 14.
178 Lighthouse Infrastructure submission to the consultation paper, p. 4.
179 ESPDD submission to the consultation paper, p. 3.

Ergon Energy and Energex stated that the proposed change to the loss factor methodology would have a material impact on the long-term interest of consumers as it would result in more risk being taken by those who are least able to mitigate it, and less risk by those who can.[180]

EnergyAustralia similarly submitted that "there are appears to be no significant justification that moving from MLF to ALF is clearly in the best interest of the consumer".[181]

## 5.3 Draft rule determination

The Commission's draft rule determination described transmission loss factors. It noted that incorporation of electrical losses on transmission lines in an electricity grid into the operation of the NEM is important to enable the wholesale price of electricity to reflect the full cost of producing and delivering that electricity to its point of consumption.

In the draft determination, the Commission also sought to explain the rationale behind the use of marginal loss factors in the NEM. It explained that MLFs represent the value of electrical energy that is lost when the next or marginal unit of electricity is transmitted across the transmission network. An MLF value specifically represents the losses between a generator or load connection point on the network and the regional reference node. This marginal approach to calculating electrical losses is consistent with how other aspects of dispatch and pricing operate in the NEM. It has been used because marginal pricing is generally considered to lead to the most efficient outcomes.

Having regard to the above, the Commission set out its view that changing the loss factor methodology to an average methodology would introduce inefficiencies into the NEM. In particular, it could change the order of dispatch. In addition, the Commission considered that average loss factors would be likely to provide a less clear and efficient locational signal to prospective generation investors. This would likely lead to more generators locating in less efficient locations, increasing customers' prices in the long-term.

While recognising that moving to an average loss factor approach could potentially benefit some investors, the Commission also expressed its concern that doing so would have a distributional impact, effectively shifting risk and costs from poorly located generators to consumers. The Commission's analysis also indicated that the IRSR (discussed in Chapter 4) would be likely to reduce and therefore result in higher electricity prices (through a relative increase in TUOS charges).

Consistent with the assessment framework set out in Chapter 2, the Commission considered the impact of moving from a marginal to an average approach to calculating transmission loss factors on the efficient operation of, and investment in, electricity services, as well as on risk allocation. The Commission's analysis, as set out in the draft rule determination, is provided below.

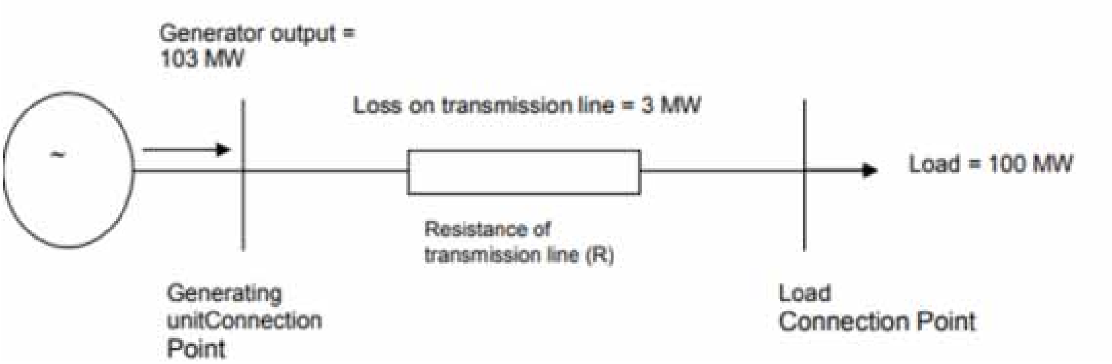
180 Ergon Energy and Energex submission to the consultation paper, attached table.

181 EnergyAustralia submission to the consultation paper, p. 7.

### 5.3.1 Difference between marginal and average loss factors

When transmitting electricity from one point to another, a portion of the energy is lost in the form of heat due to electrical resistance. This occurs predominantly in transformers and transmission lines. These losses, which occur through electricity flows, are a function of physics and are unavoidable. This is illustrated in Figure 5.1.

**Figure 5.1: Transmission line losses**




Source: AEMO

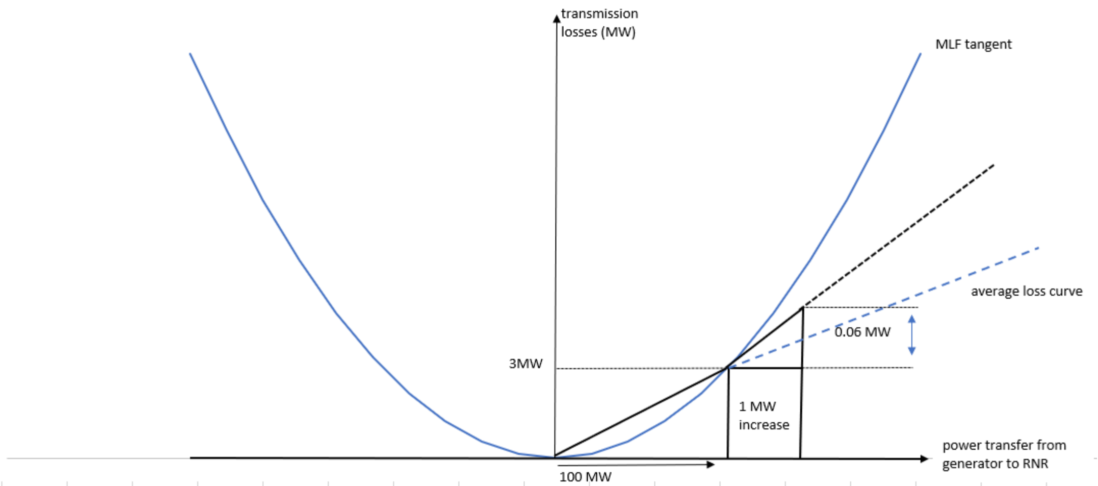
Note: The diagram above represents the loss of electricity when sending electricity from point A (generator) to point B (load). If the generator is to supply 100 MW of electricity to the load, then the generator has to generate 103 MW because of transmission losses of 3 MW.

Figure 5.2 below shows the transmission loss versus power flow characteristic for the simplified example of a generator injecting 100 MW into a transmission line that supplies load at the regional reference node, with 3 MW of losses due to the flows in the transmission line. This loss characteristic is a quadratic with the losses on the transmission line being proportional to the square of the power transfer from the generator (to the RRN).

With 100 MW injected by the generator there is 3 MW of loss and hence the average losses are 3 per cent, or 0.03. Therefore, an average loss factor for a 100 MW injection is 0.97 (i.e. 1.00 – 0.03).

The marginal loss factors used to determine the efficient dispatch of generation are based on an incremental increase in generation. In this example, for an increase of 1 MW (from 100 MW to 101 MW) the losses would increase by 0.06 MW (from 3 MW to 3.06 MW). This would give a marginal loss factor of 0.94 (i.e. 1.00 – 0.06).

**Figure 5.2: Difference between marginal and average loss factors**




Source: AEMC graph, based on AEMO, *Treatment of loss factors in the National Electricity Market*, 1 July 2012, p. 17.

### 5.3.2 Impact on efficient operation of providing electricity services

Quantitative analysis prepared by Baringa and provided to the Commission by the CEC as part of the initial round of consultation suggested that using average loss factors would lead to a more efficient operation of electricity services. It further indicated that using the average loss factor approach could lead to the lowest baseload electricity prices when compared to MLFs and compressed MLFs, leading to the lowest total consumer payments.[182]

In making its draft rule determination, the Commission reviewed the analysis provided by the CEC and noted that only the impact on cash flows in a single year of switching to a set of higher generation loss factors was considered by Baringa. Taking this analysis to its logical conclusion, it might suggest that customer outcomes could be improved by removing loss factors all together (that is, treating all generators with a loss factor of one). The Commission noted that a model based on a loss factor of one might well show that consumer payments are lower under this scenario than under the ALF scenario. However, this would provide limited information about the long-term impacts of such a change such as, what the efficiency loss associated with removing all price signals associated with losses would be. The analysis highlights the difficulty in modelling what the material impact on consumers would be under an ALF approach.

In order to assess the impact on market efficiency, the Commission undertook its own modelling of transmission loss factor methodologies to test the impact on consumer payments and the order of dispatch of generators.

182 CEC supplementary submission to the consultation paper, Baringa report, pp. 25-29.

A simple model was used that estimated an ALF value by the square root of the MLF. The model used five hypothetical generators and a single-day load profile based on an average South Australian demand. Table 5.1 summarises the assumptions used for the stylised dispatch model.

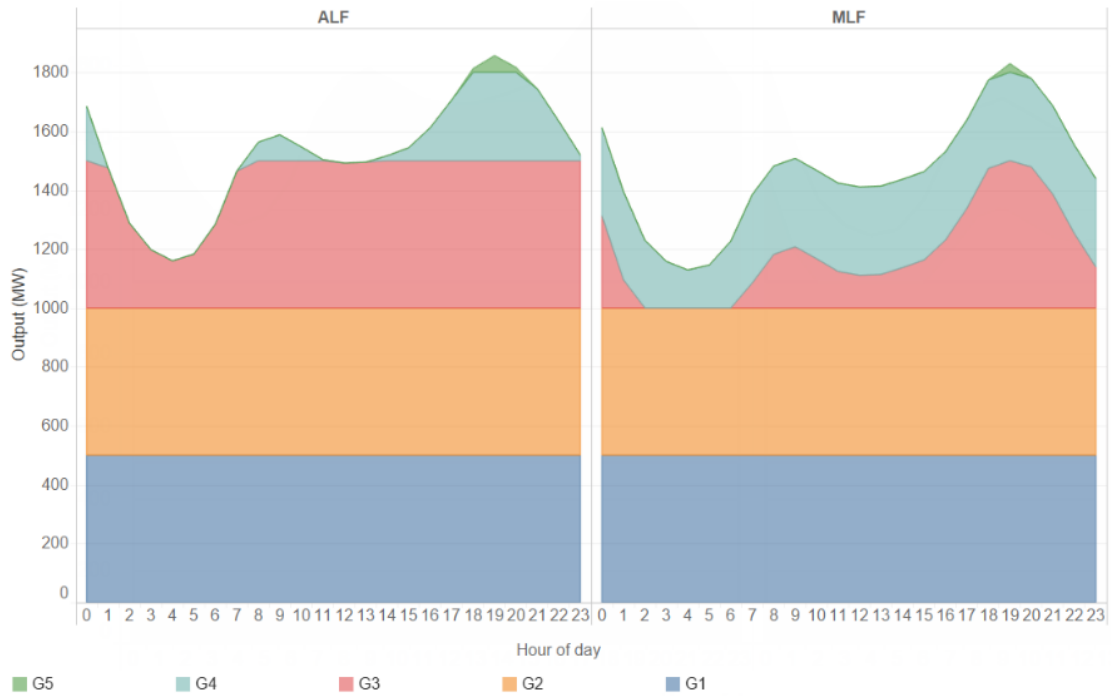
**Table 5.1: Assumptions used for stylised dispatch model**

| | G1 | G2 | G3 | G4 | G5 |
|---|---|---|---|---|---|
| SRMC | $25 | $50 | $160 | $300 | $1,000 |
| MLF | 0.99 | 0.98 | 0.500 | 0.950 | 0.900 |
| ALF | 0.995 | 0.990 | 0.707 | 0.975 | 0.949 |

Source: AEMC assumptions.

The model calculated the revenue earned by each generator and the cost to customers, after accounting for the residue. To allow losses in the model, it was run twice: a first run to estimate the losses; and a second to add the estimated losses to total generation. This was a simple model used in the draft rule determination for the purpose of yielding insights about the consequences of shifting to ALFs. It was not intended to forecast or measure actual outcomes.

**Figure 5.3: Impact on dispatch**




Source: AEMC

Note: Generators are stacked from highest to the lowest short-run marginal cost in $/MWh (SRMC). Generator 1 (G1) has the lowest SRMC and generator 5 (G5) has the highest SRMC. Compared to the MLF approach, generators with a lower SRMC are getting dispatched under the ALF approach. However, under the ALF approach more total energy is being generated and paid for by consumers because generator 3 has much higher losses than the other generators. Losses for the ALF scenario are roughly double those of the MLF scenario.

The graphs in Figure 5.3 demonstrate how a change in the loss factor methodology from a marginal to an average approach could alter the order of dispatch for generators in an electricity market. The right-hand side shows a dispatch order under a single-day load profile. On the left-hand side of the graph the same single-day load profile using average loss factors is shown. Under both examples, the dispatch order is the same until demand goes above 1,000 MW. To meet demand over 1,000 MW, there is a change in the dispatch order when an average loss factor methodology is used.

In the example in Figure 5.3:

- Generators are stacked from highest to the lowest short-run marginal cost in $/MW (SRMC).
- Generator 1 (G1) has the lowest SRMC and generator 5 (G5) has the highest SRMC.
- Under the ALF approach, generator 3 is dispatched more than generators 4 and 5, compared to under the MLF approach. Generator 3 has a lower SRMC than generators 4 and 5, but generator 3 has much higher losses than those generators. In this example, the losses under the ALF approach are roughly double of those under the MLF approach.

- The result is that more energy needs to be generated and paid for by consumers under the ALF approach compared to the MLF approach, and in this example, this implies that the ALF approach could result in a higher cost dispatch compared to the MLF approach.

In particular, the graph shows that:

- the dispatch engine will prefer to dispatch generators with higher losses under an ALF approach
- the change in the dispatch order under ALFs will affect overall system losses as generators with higher losses are dispatched compared to the dispatch order under MLFs, resulting in operational inefficiencies more to supply
- the effect of moving from MLFs to ALFs on the order of dispatch will depend upon the level of demand, the bids of the generators and the loss factors themselves.

The Commission's draft rule determination analysis showed that changing to an ALF methodology has the potential to change the dispatch order of generators for dispatch. However, its impact in the NEM would ultimately depend on the specific situation, including which generators are online and which generator is marginal.

Depending on the spread of loss factor values, changing to an average loss factor methodology could result in a change in the dispatch order. As the dispatch order changes, the amount of electricity that needs to be generated will also change. This is because a change in the dispatch order from a state of more efficient dispatch to less efficient dispatch leads to losses and so more energy needs to be generated to meet the same level of demand. In addition, the reduced locational signal associated with the use of ALFs would be likely to result in more generators locating in locations with weaker transmission infrastructure. This would mean that even if the dispatch order changes to dispatch lower cost generation, more electricity will need to be produced as these generators will likely be located in areas with higher losses.

Accordingly, in regard to operational efficiency, the draft rule determination concluded that under an ALF approach, generators with higher losses could potentially be dispatched ahead of generators with lower loss factors but higher SRMCs. While the ALF approach might provide more certainty to some investors, it comes at the expense of the potentially more efficient generators which do not get dispatched. This could ultimately result in higher electricity prices.

### 5.3.3 Impact on efficient investment

The draft rule determination also considered the impact of using an average loss factor approach on investment efficiency. The Commission stated that marginal loss factors provide important investment signals with respect to the location of new generation assets. Investors in generation assets have some discretion in deciding where to locate an asset. For example, investors can potentially choose between locating closer to load and on a stronger part of the transmission network, both of which would likely result in a higher and more stable MLF relative to a new generation investment located far away from load centres and on a weak part of the transmission network. As part of these locational decisions, prospective investors should consider the impact of current and future MLF values as one of the inputs for their revenue forecasts.

A change from marginal loss factors to average loss factors will therefore have an effect on dynamic efficiency. Dampening the locational signals would be likely to lead to more investment in parts of the power system with high losses. Over time, this would increase the amount of losses, and so the total dispatch cost. Ultimately, consumers would pay more for electricity to cover the cost of the additional electrical losses occurring as, overall, more electricity would have to be generated to meet the same level of demand.

The Commission noted that financial markets hedging products for loss factors, for example buying an insurance against MLF variability, are currently not available to investors in generation assets. However, it considered that loss factor risk could be managed by entering into long-term power purchasing agreements. In addition, some owners would be able to diversify loss factor risk by owning different types of generation assets and/or assets in different geographical locations.

A change from marginal to average loss factors would involve a transfer of risk from investors in new generation assets to consumers. However, consumers are not involved in the investment decision-making processes for new generation assets, and they would not be able to enter into long-term power purchasing agreements. Consequently, consumers are, in the Commission's view, the party least able to manage loss factor uncertainty and the resulting impact on consumer prices.

The draft rule determination noted that the Commission's COGATI review includes consideration of new hedging mechanisms for generators to increase the ability of investors in generation assets to manage risk associated with the impact of losses.

### 5.3.4 Risk allocation

The Commission's draft rule determination analysis also indicated that using an average methodology to calculate loss factors may result in a lower cost of capital for some generation assets compared to using the marginal methodology. This is largely a result of a reduction in revenue variability associated with more stable and less volatile loss factors.

However, the Commission also observed that the reduction in the cost of capital is only possible because some base risk of generation investment is transferred from generators to consumers. The draft rule determination discussed how changing to an ALF approach could impact on the cost of debt, the cost of equity and what the distributional impacts would be.

#### Impacts on the cost of debt

One of the arguments made by stakeholders in submissions to the consultation paper was that the current volatility in MLFs results in an increase in the cost of capital for generation assets. PARF noted that this increase in the cost of capital applies to both debt and equity financing.[183]

183 PARF submission to the consultation paper, p. 7.

This argument applies to both incumbent generators and new entrants as incumbent generation generally needs refinancing of debt every five years.

The variability in MLFs appears to be impacting the ability of some generator owners to service debt. As MLFs reduce (indicating higher losses):

- existing generators earn less revenue while their costs remain unchanged
- new generation investment requires a higher rate of return as the probability of revenue variability and reduction means higher default risk.

Consequently, all other things being equal, the debt risk premium will increase and the gearing ratio will decrease. A decrease in the gearing ratio means that more equity capital will be required to finance the investment. As equity capital is more expensive than debt, this will impact the cost of capital of new generation investment and existing generation investment at refinancing. The same principle would also apply to owners of existing generators when refinancing their debt.

#### Impacts on the cost of equity

The ACIL Allen report submitted by PARF noted that equity investors seek stable returns:[184]

> ...the current variability and relative unpredictability of MLFs, if left unchecked, will not only lead to greater amounts of more expensive equity capital required (as lenders decrease total dollar debt available for generation projects), equity investors will also add additional risk premia for existing and new investments in renewable energy.

The effect of increasing loss factor volatility on the cost of equity is two-fold. First, reduced debt financing availability means a lower gearing ratio. The result is that more of the relatively more expensive equity finance would be required. Second, volatility in loss factor values coupled with some significant reductions caused by new connections have increased generators' revenue volatility. All other things being equal, this would cause an increase in the cost of equity.

The Commission also noted in the draft rule determination that investors submitted that loss factor risk is currently not able to be hedged. As observed by the CEC, loss factor variability is currently an unmanageable risk that cannot be hedged by industry.[185] However, other stakeholders noted that while there are no hedging products available for loss factor risk, generator owners can manage this risk by entering into long term power purchasing agreements where possible. In addition, larger owners would be able to diversify away some loss factor risk through owning multiple generators in different locations.

#### Distributional impacts

The Commission's draft rule determination also considered the impact that a change to an average loss factor methodology may have on generators. In particular, the Commission recalculated loss factors of generators in the NEM using the square root of the MLF as an

184 PARF submission to the consultation paper ACIL Allen report, p. 7.

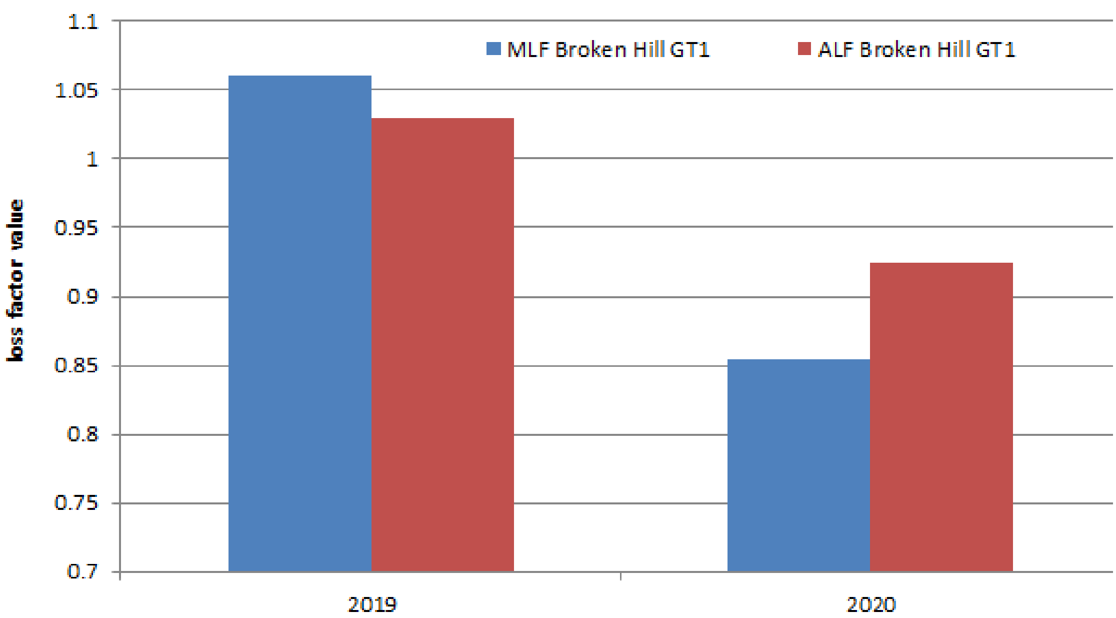
185 CEC submission to the consultation paper, p. 1.

approximation of average loss factors. These calculations indicated that using an average methodology to calculate transmission loss factors would be likely to increase loss factors that had been lower than the average in a region and decrease loss factors that had been higher than the average in a region. This effect would be likely to result in:

- a change in the dispatch order
- an increase in revenue for some generators and a decrease in revenue for other generators
- less efficient location signalling for future generation investment.

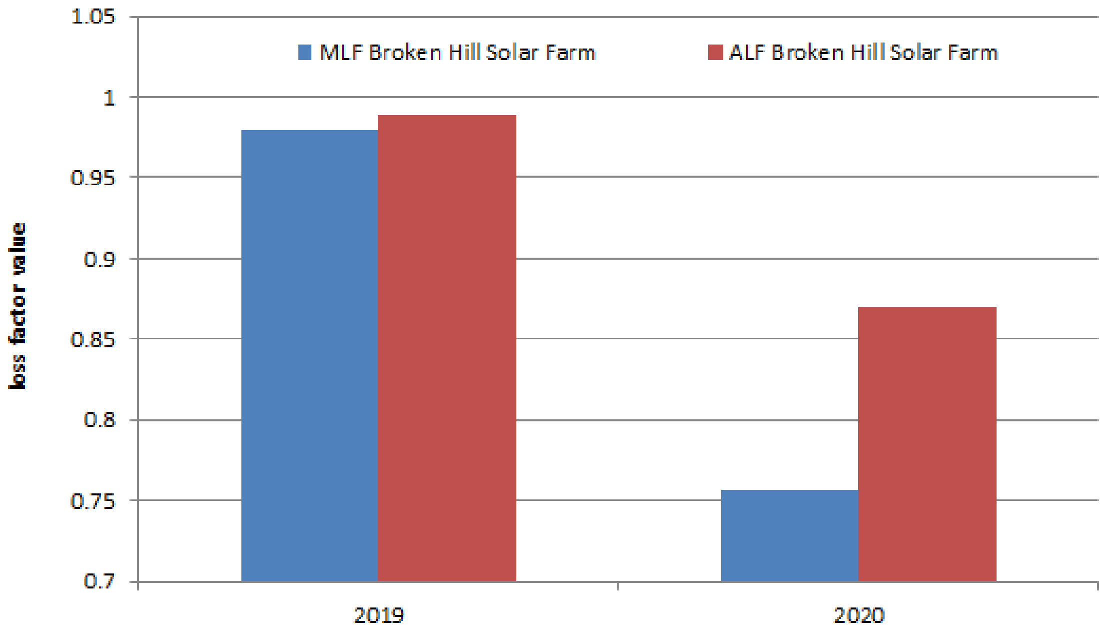
This was illustrated in Figures 5.4 and 5.5 which show marginal and average loss factors for generators in Broken Hill, New South Wales. The figures show that an average methodology could result in lower or higher loss factors compared to the MLF. Figure 5.4 shows that applying an average methodology in 2019 would have resulted in a reduced loss factor value compared to the MLF value. This lower loss factor value would likely result in less revenue for the Broken Hill GT1 plant. Figure 5.5 shows that a change from MLF to ALF for Broken Hill solar farm would increase the loss factor values in both 2019 and 2020.

**Figure 5.4: Applying an average methodology — Broken Hill GT1**




Source: AEMO, AEMC
Note: ALF calculated using the square root of the published MLF.

**Figure 5.5: Applying an average methodology — Broken Hill solar farm**




Source: AEMO, AEMC
Note: ALF calculated using the square root of the published MLF.

### 5.3.5 Draft rule determination conclusion

In the draft rule determination, the Commission concluded the following:

- Using average loss factors would represent a departure from the economic framework of the NEM which is based on marginal pricing. This could result in inefficient dispatch.
- Average loss factors would dampen locational signals compared to marginal loss factors. This is likely to increase losses and congestion as new generators will be likely to locate in less efficient locations.
- Moving to an average loss factor methodology could provide more stable and predictable loss factor values. This would help reduce revenue volatility and lower the cost of capital for investors in some generation assets.
- However, moving to an average loss factor methodology would also shift risk away from those parties best placed to manage it (investors in new generation assets) to those who are least able to manage it (consumers). This is likely to result in further inefficiencies and hence higher costs for consumers.
- Average loss factors are likely to decrease the loss factors of generators with relatively high MLFs and increase the loss factors of generators with relatively low MLFs.

For the above reasons, the Commission concluded that the use of an averaging methodology for determining transmission loss factors in the NEM would not represent an improvement in the determination of loss factors and consequently would be unlikely to better contribute to the achievement of the NEO than the draft rule.

## 5.4 Public hearing

In its request for a pre-final rule determination hearing, John Laing (also on behalf of the CEIG) argued that the AEMC did not adequately consider the NEO in its draft rule determination.[186] In its request for a hearing, Lighthouse Infrastructure similarly argued that the AEMC's draft determination did not properly assess the relationship between certainty of investment signals and the cost of investment capital. In addition, it considered that the proposed COGATI reforms are too far away and that an interim solution to the current issues with transmission loss factors is needed.[187]

At the pre-final rule determination hearing, Infigen stated that "...moving away from marginal losses risks less efficient dispatch outcomes".[188] Infigen Energy noted that investments have been hit due to changing loss factor values and that this is a real issue, but pointed out that this:[189]

> ...shouldn't override the underlying laws of physics and economics and we shouldn't be trying to change those to solve the problem. This is really an asymmetric information and transparency issue, not a fundamental design problem.

In contrast, the CEIG argued that it is:[190]

> ...somewhat concerned that the emphasis has been put on, you know, two important aspects of the current MLF methodology around dispatch efficiency and locational signalling. But first of all, not really enough quantitative analysis has been included in a draft determination for us to be able to weigh up those benefits versus what we also see as the benefits of moving to an ALF.

The CEIG noted that, according to the AEMO Integrated System Plan (ISP), investors need to deliver 35 GW of new generation and 15 GW of storage by 2040. It has calculated that retaining the MLF methodology would leave investors with two options:[191]

- CEIG members keep investing and include (+2 per cent) MLF premium equalling to $430 extra per customer
- CEIG members stop investing and left to oligopoly equalling to $1,075 extra per customer.

186 CEIG request for pre-determination hearing.
187 Lighthouse Infrastructure request for pre-determination hearing.
188 AEMC transcript of pre-final rule determination hearing, p. 17.
189 AEMC transcript of the pre-final rule determination hearing, p. 16.
190 AEMC transcript of the pre-final rule determination hearing, p. 5.
191 CEIG presentation provided at the pre-final rule determination hearing, p. 3.

The CEIG submitted that they are not equipped to model all the inputs into a full model, such as the interregional settlement pool or the size of that under an ALF methodology and requested the AEMC provide such an analysis to better explain its decision.[192]

Other members of the CEIG also questioned the merits of the draft rule determination. For example, Lighthouse Infrastructure pointed out that:[193]

> ...relying on individual generation developers and investors to forecast an MLF is-whose primary driver is actually subsequent activities of other market participants feels to us like a poor way of delivering that efficient system plan.

In addition, Innogy noted that:[194]

> ...we, to, are supporters of robust locational signals, but the most accurate signal of where to build today is of little use to an investor in a 30-year asset if the signal can fluctuate significantly after the investment is made. At that point, the signal is too late.

Similarly, the CEC argued that the draft rule determination did not provide sufficient quantitative analysis on the MLF risk premium and did not recognise that large users also have an MLF. It also noted that, in its view, the quantitative analysis undertaken by its consultant Baringa has been unfairly dismissed by the AEMC as stylised.[195]

The QIC also presented at the pre-final rule determination hearing. It stated that it had estimated that the weighted average cost of capital for greenfield developments in generation has increased by 25 per cent as a result of the increased uncertainty and volatility associated with the current MLF methodology. It considered that this will feed directly into electricity prices which will not contribute to the NEO.[196] The QIC submitted that:[197]

> ...the AEMC to engage and work closely and constructively with the CEIG and its member prior to any final decision being made. It is important that quantitative analysis is undertaken to understand the merits of both the MLF and ALF methodologies. In our view, which is supported by that quantitative analysis, the ALF approach represents the optimal balance between restoring investor confidence by making these loss factors more predictable and stable, as well as retaining locational signalling aspects of the existing approach to assist with the grid planning objectives.

192 AEMC transcript of the pre-final rule determination hearing, p. 6.
193 AEMC transcript of the pre-final rule determination hearing, p. 8.
194 AEMC transcript of the pre-final rule determination hearing, p. 9.
195 AEMC transcript of the pre-final rule determination hearing, p. 13.
196 AEMC transcript of the pre-final rule determination hearing, p. 15.
197 AEMC transcript the pre-final rule determination hearing, p. 16.

## 5.5 Stakeholder views on the draft rule determination

In response to the draft rule determination, numerous stakeholders submitted that they agreed with the Commission's draft decision to maintain a marginal approach to transmission loss factors.[198] For example, Tilt Renewables stated:[199]

> Tilt renewables supports the AEMC's draft rule determination contained in the report of 14th November 2019, including the rejection of the "average loss factor" approach and the pragmatic changes to assists AEMO's calculations of marginal loss factors.

In addition, Origin noted:[200]

> We agree with the Commission that ALFs:
>
> - Are inconsistent with the concept of marginal pricing and could result in inefficient dispatch of generation
> - Would dampen locational signals, leading to inefficient locational decisions.
>
> While ALFs would help reduce volatility, which may lead to lower cost of capital costs for some new generation assets, due to the issues mentioned above, we continue to oppose a move to ALFs. On balance, we consider that the benefits would not outweigh the costs and distortionary effects of moving away from a marginal framework.

The ENA also noted that MLF volatility reflects a broader set of generation and transmission issues beyond the scope of this rule change, stating:[201]

> ...initiatives such as actioning of the Integrated System Plan (ISP), Coordination of Generation and Transmission Investment (COGATI), and the ESB's post 2025 market review project are all necessary to address the fundamental issues arising in this transition. In particular the COGATI review is expected to implement dynamic loss factors and may consider the appropriateness of hedging arrangements for loss factors in the design.

However, other stakeholders did not agree, remaining of the view that average loss factors are preferable over marginal loss factors. A number of issues were raised in submissions, including:

- the Commission's use of quantitative modelling in making its draft rule determination
- impacts on operation and investment efficiency and the allocation of risk
- impact on the cost of capital for generation assets, and
- transparency of information.

These are each discussed in turn below.

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198 See submissions to the draft determination: the ACCC, p. 2; AEMO, p.1; AER, p.1; AGL, p.1; AEC, p.1; ENA, p.1; Energy Australia, p.1; Engie, p.1; EUAA, p.1; Infigen, p.1; Origin, p.1; Department of Energy and Mining SA, p.1; Snowy Hydro, p.1; Stanwell, p.1; TasNetworks, p.1.

199 Tilt Renewables submission to the draft determination, p.1.

200 Origin submission to the draft determination, p. 1.

201 ENA submission to the draft determination, p. 2.

### 5.5.1 Use of quantitative analysis

In their submissions to the draft rule determination, some stakeholders considered that the Commission did not provide adequate quantitative analysis to support its decision to maintain the MLF framework. For example, the CEC submitted that:[202]

> The CEC urges the AEMC to include further analytical work in its final determination to ensure a robust quantitative and qualitative assessment of the issue. For example, an average loss (ALF) factor framework could reduce the intra-regional settlement residue (IRSR) as the use of MLFs generally tends to result in an over-recovery of funds from settlement. However, no analysis has been undertaken into the magnitude of the IRSR under different TLF methodologies nor the potential that a changed methodology and subsequent IRSR changes could lead to a redistribution of wealth between different parties. The final determination should explore these matters more fully.

The CEIG also requested the Commission undertake analysis to support its draft rule determination:[203]

> The CEIG and other stakeholders who have invested the time and cost of proper analysis recommend to AEMC in the strongest possible terms that appropriate and transparent quantitative assessment of the relative merits of the ALF and MLF methodologies be included in the final determination. Without such, neither consumers nor investors can be confident that the NEO is being properly considered by the AEMC.

This comment was repeated by individual members of the CEIG (Windlab, ESCO Pacific, Foresight Group, PARF, Innogy Renewables and QIC) and the CEC.[204]

These submissions on the quantitative analysis provided by the Commission in the draft rule determination are addressed in section 5.6.2 below.

### 5.5.2 Efficiency and risk allocation

In its submission, the CEIG argued that the Commission, in it's draft rule determination, did not adequately consider the NEO.[205]

In particular, these stakeholders asserted that the draft rule determination included a number of statements on the assessment criteria without providing sufficient quantitative or qualitative evidence. These comments are set out below in relation to efficient investment and operation, and risk allocation.

202 CEC submission to the draft determination, pp. 1-2.

203 CEIG submission to the draft determination, p. 7.

204 CEC submission to the draft determination, p.1.

205 CEIG submission to the draft determination, p. 2. Note that CEIG members provided an identical submission to the draft rule determination which include Windlab, ESCO Pacific, Foresight Group, PARF, Innogy Renewables, and QIC.

### Efficient investment

The CEIG considered that the ALF framework provides the same locational signal as MLFs because the relative ranking of different locations would remain the same. The CEIG also believes that:[206]

> The disproportionate weighting given to the MLF as a locational signal is inconsistent with the principles of AEMO's Integrated System Plan ("ISP") and the Renewable Energy Zone ("REZ") framework which has identified the locations for future generation investment.

Some stakeholders also noted that exposing a generator to ongoing volatile MLFs after the plant has been built, increases its costs with little likely improvement in efficiency.[207]

While Enel Green Power broadly accepted the conclusions reached in the draft rule determination, it noted that:[208]

> However, we consider there may be merit in the AEMC considering some form of interim 'time limited' solution for managing loss factor risk for participants, until such time more comprehensive changes to the loss factor framework are considered as part of the AEMC's coordination of generation and transmission investment (COGATI) review.

### Operational efficiency

Modelling provided by Baringa as part of the CEC's submission to the consultation paper indicated that adopting an ALF framework would result in a reduction in wholesale electricity prices and "consumer payments" across all five NEM regions.[209]

The CEIG and the CEC argued that the Commission had dismissed the conclusions of the modelling provided by Baringa, instead relying on a chart reflecting a stylised example on the impact of a change to an ALF framework on dispatch efficiency:[210]

> The AEMC's approach and level of analysis is not commensurate with the importance of the issue under consideration and the CEIG recommends undertaking further analysis including detailed quantitative analysis to assess the relative impact of the ALF and MLF on operational efficiency.

### Risk allocation

The draft rule determination included a comparison of the market cost of capital with the cost of capital for generation investments under an MLF framework. This, according to the CEIG,

206 CEIG submission to the draft determination, p. 3.

207 Enel Green Power submission to the draft determination, p. 1. Similar comments were made at the public hearing by Lighthouse Infrastructure; AEMC transcript of the pre-final determination hearing, p. 7.

208 Enel Green Power submission to the draft determination, p. 1.

209 CEC supplementary submission to the consultation paper, Bargina report.

210 CEIG submission to the draft determination, p. 4.

was flawed analysis as the Commission should have compared the cost of capital under an MLF framework to the cost of capital under an ALF framework.

The CEIG has also argued that the Commission's statement that some investment risk relating to MLF volatility can be diversified away is flawed because this assumes that a portfolio has to include projects which have a negative correlation to MLF movements.

In summary, the CEIG submitted that, in relation to the allocation of risk:[211]

> The AEMC's focus on risk allocation as a zero-sum game limited to transfers between investors and customers is flawed. The AEMC has the ability to reduce and remove unnecessary risks emerging from the market design that creates a more stable and competitive investment environment and improves long-term customer outcomes.

### Volatility in loss factor values

Submissions to the draft rule determination also reiterated previous submissions made to the consultation paper on the impact of loss factor volatility on investment in the generation sector.

For example, the CEIG argued that loss factor volatility impacts incumbent and future generator revenue significantly, and an immediate response is necessary to avoid higher consumer prices and a reduction in new generation investment. The CEIG proposed that:[212]

> ...moving to an Average Loss Factor ("ALF") methodology as an immediate step to achieve an optimal balance between the need for investor certainty and the need for the accurate calculation and apportion of losses in electricity supply. This change also provides for the balancing of key stakeholder objectives, namely the need for investment certainty, efficient locational signalling, calculation simplicity and ease of implementation.

While some stakeholders argued that a move to average loss factors could improve the investment climate, others considered that investors must remain exposed to the consequences of their siting decisions in proportion to their marginal impact on the power system.[213] In particular, the AEC noted that:[214]

> Marginal loss pricing remains an essential part of:
>
> - dispatch efficiency as two competing generators at extreme ends of the NEM can have a marginal loss equivalent factor between them as high as 2:1; and
> - locational efficiency – as generators should be encouraged to site close to load. This is particularly the case where the two main new-generation fuel sources, sun and wind, are ubiquitous but vary geographically in intensity. Since developers are exposed to the intensity signal, it is critical that they are also exposed to the

211 CEIG submission to the draft determination, p. 6.

212 CEIG submission to the draft determination, p. 2.

213 AEC submission to the draft determination, p. 1.

214 AEC submission to the draft determination, pp. 2-3.

> marginal loss signal. Externalising one side of the trade-off would be seriously distortionary.

The CEC also submitted that the draft rule determination did not consider the impact of using different loss factor methodologies on load (that is, users of electricity).[215]

Submissions on the draft rule determination regarding the assessment of efficiency and risk are addressed by the Commission in section 5.6.1.

### 5.5.3 Impacts on the cost of capital

A number of stakeholders commented on the impacts of MLF volatility on the cost of capital for generation investments.

While the AEC noted that an ALF methodology has the potential to lower risk for investors, it argued that:[216]

> Other things being equal, lowering the cost of capital is consistent with the market objective and should be pursued with respect to non-physical matters, such as the perceived risk of intervention. However parabolic losses are a reflection of the physical power system and cannot be eliminated. Financial exposure to them can be moved downstream as proposed in the Rule, with upstream risk commensurately lessened, but the total risk across the industry would actually increase as it has simply been moved on to parties uninvolved in its causation.
>
> Ad absurdum this cost of capital argument suggests investors should never be exposed to market signals as risk-free capital is always cheapest.
>
> Marginal loss pricing has been a feature of the NEM since its inception. A sudden change to the arrangements would substantially shift the competitive deckchairs, with those who have invested with greatest attention to losses disadvantaged. The NEM's reputation regarding stability of rules would be harmed, in fact increasing investment risk in exactly the opposite way intended.

While Enel Green Power broadly agreed with the Commission's draft rule determination, it pointed out that once an investment has been made, there is little a generator can do to influence losses, other than reducing its dispatch. [217]

However, the CEC submitted that the impact on the cost of capital should not be understated:[218]

> In the market, MLF risk is manifesting itself in increased risk premiums for new projects, as well as more onerous revised terms during the re-financing of existing generators. Some of our members anecdotally report that a one to two percentage

215 CEC submission to the draft determination, p. 2.

216 AEC submission to the draft determination, p. 2.

217 Enel Green Power submission to the draft determination, p. 2.

218 CEC submission to the draft determination, p. 2.

> points premium is currently being added to the cost of capital for new renewable projects in Australia as a result of MLF risk.
>
> The implications of a higher WACC are two-fold. Firstly, a higher cost of capital increases the levelised cost of energy, resulting in higher prices for consumers. Secondly, it is already deterring investment in new generation and it is entirely possible that renewable investors will withdraw from the Australian market to invest in markets with less loss factor volatility.

The CEC also commented that the result of an investor survey recently conducted by the Commission should be helpful in investigating the impacts of loss factor volatility on the WACC of generation investments.[219] In addition, the CEIG requested the Commission reconsider the cost of capital analysis it undertook as part of the draft rule determination. In the CEIG's view, the analysis:[220]

> ...incorrectly compares the higher cost of capital due to MLF uncertainty to the"market" cost of capital rather than what the cost of capital would be without the MLF uncertainty. The CEIG recommend that the AEMC correct the error in their cost of capital analysis and update the assessment of the relative merits of the ALF and MLF frameworks to reflect the adverse customer pricing impact as a result of the uncertainty associated with retaining the existing MLF framework.

Submissions regarding the cost of capital analysis provided as part of the draft rule determination are addressed below in section 5.6.3.

### 5.5.4 Transparency issues

Submissions were generally supportive of the Transparency in new projects rule change and the additional information provided by AEMO on indicative loss factors.  For example, in its submission, AGL:[221]

> ...points to the Transparency in New Projects rule change and AEMO's recently published indicative 2020-21 MLF publication as key efforts aimed at increasing the information and data available to prospective developments. This newly accessible information together with an increased commitment from AEMO to publish projected MLF trajectories should assist participants in their commercial assessment to make financial investment decisions within their level of comfort.

Similar comments were also made by the AEC:[222]

> The AEC also supports the draft's minor rule changes, which, along with recent rule changes to support connection transparency and initiatives underway at AEMO to

219 CEC submission to the draft determination, p. 2.

220 CEIG submission to the draft determination, p. 5.

221 AGL submission to the draft determination, p. 1.

222 AEC submission to the draft determination, p. 1.

> improve loss factor predictability, should help future investors avoid the negative surprises that spurred this rule change proposal.

However, another stakeholder considered that these initiatives are not enough to address stakeholders' concerns:[223]

> The CEC is cognisant of the recent work undertaken by the AEMC to increase information transparency of new projects and the increased publication of MLF trend analysis by the Australian Energy Market Operator (AEMO). While both efforts and the recommendations outlined in the draft determination are valued by the clean energy industry, they do not adequately address the increased volatility faced by existing renewable generation.

The Commission's consideration of the additional information provided by AEMO are provided in Chapters 6 and 7 of this final rule determination.

## 5.6 Final rule determination assessment

The Commission decided that the marginal loss factor framework will, or is likely to, better contribute to the achievement of the NEO than an average loss factor framework as proposed by Adani Renewables. The Commission has considered stakeholder submissions and the presentations at the public hearing in response to its draft rule determination. It consequently undertook additional quantitative analysis and used the results of its modelling to understand if an average loss factor framework would or would be likely to better contribute to the achievement of the NEO relative to a marginal loss factor approach. Overall, the Commission found that:

1. In considering the long-term impact on customers of moving from a marginal to an average loss factor framework, changes in total customer payments, which include changes in transmission use of system charges (TUOS), must be considered.
2. Customer payments are equal to the generator payments – where generator payments are equal to the spot price of electricity multiplied by the quantity dispatched multiplied by the transmission loss factor. Customer payments compromise two parts: the price paid for energy, equal to the spot price of electricity multiplied by the quantity consumed multiplied by the transmission loss factor; and the IRSR, which is either returned to customers through a reduction in TUOS charges, if the IRSR is positive, or paid for by customers if the IRSR is negative.
3. Baringa's modelling did not take into account the impact of a move to average loss factors on IRSR, and hence the impact on TUOS. Rather, it focused solely on the expected change in spot prices. The Commission considers that it therefore does not provide a full picture of the total impact on customers.
4. The Commission undertook a similar modelling exercise to that undertaken by Baringa (summarised in detail in Appendix E) which did consider expected changes on the IRSR

223 CEC submission to the draft determination, p. 1.

from a change to an average loss factor framework. The Commission's modelling shows that the claim made by Baringa that customer payments would be lower under ALFs is incorrect.[224] The AEMC's modelling results show that the impact on customer payments depends on the conditions of dispatch. There is evidence that aggregate customer payments could be higher under ALFs, based on the sensitivities that the Commission has modelled.

5. The Commission then undertook additional modelling (also summarised in detail in Appendix E) and considered potential transfers in wealth between individual generators as a consequence of changing to average loss factors. To do this, the Commission modelled the change in generator receipts. Modelling results confirmed the Commission's draft rule determination analysis that although in aggregate, the effect of changing to ALFs on generator receipts is small, the change can have a significant effect on the revenue of individual generators.
6. The draft rule determination also referred to a stylised example of the impact of changing to average loss factors on dispatch.[225] The Commission tested the conclusions drawn from this stylised example and the first principles analysis in the draft rule determination, that ALFs can have an impact on the order of dispatch. Additional modelling (Appendix E) shows that the dispatch order can change under an ALF framework and although in aggregate the effect of changing to ALFs on generator receipts is small, the change can have a significant effect on the revenue of individual generators.
7. Increases in the WACC of existing generators over the life of the asset can be impacted by a range of factors such as significantly longer time-frames for connecting and commissioning new plant, security output constraints, congestion risk and the nature of an open access regime, rather than the loss factor methodology specifically.

The next section sets out these considerations in regard to:

- the use of additional quantitative analysis
- investment and operational efficiencies and risk allocation in the NEM
- impacts on the cost of capital.

Further detailed analysis is set out in Appendix E.

### 5.6.1 Quantitative analysis undertaken by the AEMC

In this section, the Commission outlines:

1. Its review of the analysis of the customer benefits of moving to ALFs put forward by Baringa.[226]
2. Its own modelling of moving to ALFs, where the Commission has examined:
    a. the change in customer benefits
    b. the change in dispatch outcomes.

224 CEC supplementary submission to the consultation paper, Baringa report, p. 28.
225 AEMC, transmission loss factors draft rule determination, 14 November 2019, pp 53 - 55.
226 CEC supplementary submission to the consultation paper, Baringa report.

### Commission's review of Baringa's analysis

One of the submissions to the draft determination contained analysis, prepared by Baringa[227], that sought to quantify the changes in customer payments associated with moving from MLFs to ALFs. The AEMC has reviewed this modelling and found that Baringa's method is incomplete, and therefore their findings are incorrect.

The Commission found that the modelling undertaken by Baringa does not take into account the effect of the IRSR in the assessment of customer payments. This omission means that the conclusion drawn by Baringa that lower spot prices translate into lower customer payments is in fact, incorrect.

***Background – Understanding the IRSR and modelling customer payments***

In order to understand the IRSR, it is helpful to consider a simplified model of the power system (see Box 1).

#### BOX 1: CALCULATING IRSR

Figure 5.6 provides a simplified illustration of a power system comprising three nodes: a generator, the RRN, and a load. Losses are incurred between:

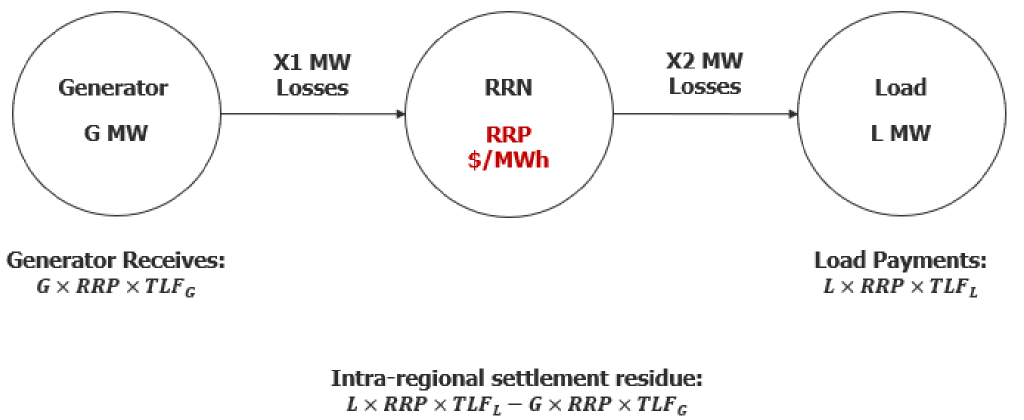
- the generator and the regional reference node, denoted X1, and
- the RRN and the load, denoted X2.

Figure 5.6 also shows that the IRSR can be calculated by subtracting generator receipts from load payments. Figure 5.7 shows the relevant values needed for the calculation of the IRSR that can be computed by NEMDE. The third figure (Figure 5.8) shows the data needed to calculate the IRSR that cannot be computed by NEMDE (AEMO's market model to operate the NEM).

Figure 5.8 shows the calculations of what the generator receives, what the load pays through the settlement process, and the IRSR which is transferred to customers through reductions in TUOS.

227 CEC supplementary submission to the consultation paper, Baringa report

**Figure 5.6: Calculating the IRSR in a simple three-node model**

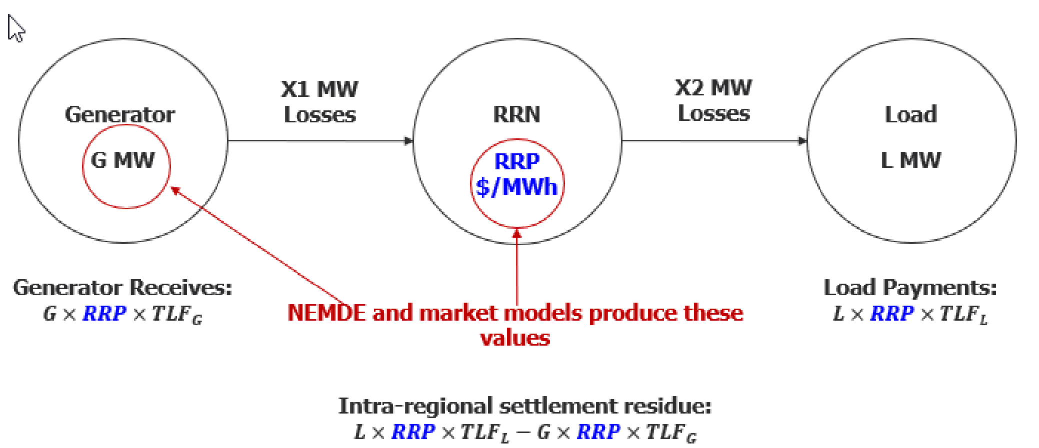



Source: AEMC
Note: Where G is the amount of electricity generated, RRP is the regional reference price. TLFg is the transmission loss factor for generation, and L is load (demand).

NEMDE and the market models that seek to replicate its operation solve dispatching the generators (G) to match the demand of the system. This demand is measured at the generator's terminals and includes the consumption at the load (L) plus the losses in the network (X1 and X2) to transmit the energy from the generator to the load. NEMDE produces a spot price at the RRN.

Importantly, the losses and the load are not explicitly modelled in NEMDE. Losses are represented by transmission loss factors. Load information is available through the settlements process, which is separate to operation of NEMDE.

**Figure 5.7: Calculating the IRSR - values supplied by NEMDE- values**




Source: AEMC
Note: Where G is the amount of electricity generated, RRP is the regional reference price. TLFg is the transmission loss factor for generation, and L is load.

Customer payments are given by the load payments less the IRSR. We have described that

NEMDE does not explicitly model load, and so load payments and the IRSR cannot be explicitly calculated without access to settlement data.

However, the equation in Figure 5.9 shows that we do not need to estimate load payments or the IRSR to determine what customers pay. Instead, we can calculate generator receipts – a value that can be determined using the outputs of NEMDE and market models. The equation in Figure 5.9 makes intuitive sense – ultimately customers must pay what generators receive.

**Figure 5.8: Calculating customer payments**

Customer payments = Load payments – IRSR

= Load Payments – (Load Payments – Generator Receipts)

= Generator Receipts

Source: AEMC
Note: Where the IRSR is the intra regional settlement residue.

Source: AEMC

***Baringa's method for modelling customer payments***

Baringa's modelling of customer payments involves two steps:

1. Modelling of wholesale electricity prices.
2. Multiplying these wholesale electricity prices by 'projected load volumes' to determine customer payments.

Baringa claims that the reduction in wholesale prices translates to a direct reduction in consumer payments, stating that[228]:

> This reduction in wholesale prices can be expected to flow through to a reduction in the wholesale price component of consumer bills. In QLD, for example, the reduction in total annual consumer payments for wholesale electricity with ALFs … equates to around a two per cent reduction.

***Response to Baringa's modelling***

In the Commission's opinion, Baringa's method is incomplete and its findings could therefore be misleading. The Commission has made three key observations:

1. Baringa's finding that spot prices decrease under ALFs is not significant and does not stem from any improvement in dispatch efficiency or cost reduction.
2. Baringa's analysis does not account for the effect of moving to ALFs on the IRSR, and is therefore incomplete.
3. Baringa does not identify that a shift to ALFs will increase losses, and so increase the amount of generation required to meet final load.

228 CEC supplementary submission to the consultation paper, Baringa report, p. 28.

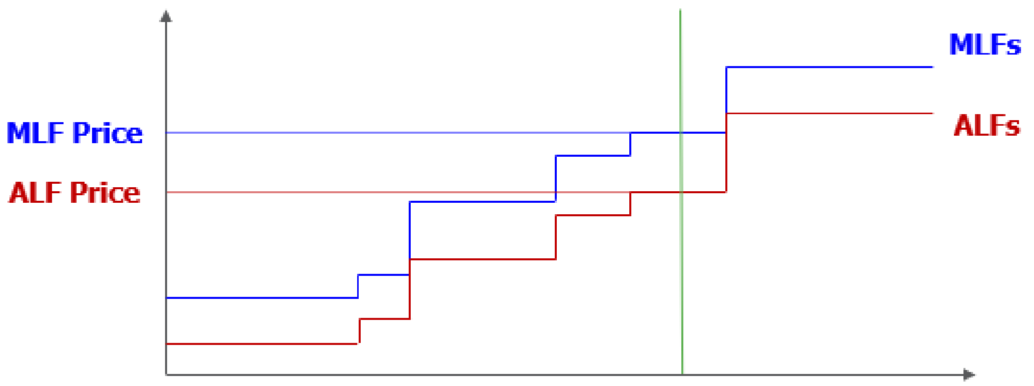
Each of these are considered below.

***Baringa's finding that spot prices decrease under ALFs is not significant***

The fact that spot prices decrease under ALFs is unremarkable in that it does not require any detailed, significant modelling to predict.

It is critical to understand *why* spot prices decrease under the ALF approach. In doing so, it is helpful to think of the National Electricity Market Dispatch Engine (NEMDE) as drawing a supply curve as illustrated in Figure 5.9 below.

Figure 5.9: **NEMDE supply curve under MLFs and ALFs**




Source: AEMC
Note: The x-axis depicts the quantity generated and the y-axis depicts the price of a unit of electricity generated.

To build this supply curve, NEMDE takes the bids of each generator and divides them by that generator's loss factor. NEMDE then uses the supply curve to select the cheapest combination of plant and interconnector flows to meet demand in each region.

It follows that moving from MLFs to ALFs means that the raw bids are divided by larger numbers, and so the supply curve will be lower for any specified level of demand. This implicitly assumes that MLFs are all less than or equal to 1, which they are for the vast majority of generation volumes.

Put simply, under an ALF approach the model divides bids by larger numbers, and so all else being equal the clearing price is lower than under an MLF approach. Note that if a loss factor of 1 was assumed for all generators, then spot prices would be even lower. Taking the argument to the extreme, if offers were divided by numbers greater than 1, then dispatch would be at prices lower than generators' bids which is an illogical outcome.

There is a tendency to assume that lower spot prices are a sign of lower cost, more efficient dispatch. However, in this instance, the lower spot prices are simply a function of the way bids are represented in the dispatch engine. The cost of dispatch cannot be lowered by using ever-greater, ever-more inaccurate loss factors. This implies that something is missing from the analysis.

***Baringa's analysis does not account for the IRSR and so is incomplete***

The Commission has observed that Baringa's analysis fails to take account of the fact that while higher loss factors reduce spot prices, they increase the payments that generators receive at those lower spot prices (see Figure 5.10).

**Figure 5.10: Calculating generator receipts**

$$\text{Generator Receipts} = \text{Generator Dispatch} \times \text{Regional Reference Price} \times \text{Loss Factor}$$

Source: AEMC

Baringa has focussed on the part of equation 5.10 above that decreases (the load payments), without accounting for the IRSR. Note that if generator receipts are constant, decreases in load payments necessitate an equal and offsetting decrease in the IRSR. In effect, Baringa has measured an inherent benefit of moving to ALFs, reductions in load payments, whilst ignoring the attendant costs.

A complete assessment of the costs and benefits of moving to ALFs must account for the IRSR. The method for achieving this is to model generator receipts. We investigate this using our own modelling below.

***Baringa does not identify that a shift to ALFs will increase losses, and so increase the amount of generation required to meet demand.***

The Commission's final observation is that Baringa has not identified that a shift to ALFs will increase losses, and so increase the amount of generation required to meet demand.

Whenever a generator with a lower loss factor displaces a generator with a higher loss factor, the total quantity of losses in the system will increase. It follows that more generation is required to meet the same level of final load.

NEMDE and the market models that seek to replicate it do not explicitly model intra-regional losses. Instead, the 'demand' targets in NEMDE are based on generation rather than final load and losses are represented by transmission loss factors.

In modelling the outcomes under MLFs and ALFs it is necessary to assume a level of 'demand' for each half-hourly dispatch interval. Under ALFs, there will be a different pattern of dispatch that tends to use generators with lower loss factors. It follows that the level of 'demand' under ALFs will be greater than or equal to the level of demand under MLFs.

There is no obvious, robust way to adjust the demand used in a market model to account for the additional losses. In its own modelling, the Commission has made a simplifying assumption of the same demand targets for both MLFs and ALFs. However, it is important to recognise that this:

- underestimates the total generation required, and so the customer payments, under the ALFs case, and
- underestimates the change in dispatch volumes under the ALFs case.

Baringa does not state in their report what assumption they have made in this regard. Presumably, Baringa has also used the same demand targets for both MLFs and ALFs. Baringa does not appear to have recognised that this underestimates the customer payments under the ALFs case.

**Additional modelling undertaken by the AEMC**

In order to investigate the effect of moving to ALFs on customer benefits, the Commission has undertaken its own market modelling. The Commission examined the following:

1. The change in customer payments arising from a shift to ALFs, using the correct method of measuring the change in generator receipts.
2. The effect of a shift to ALFs on dispatch outcomes.

The remainder of this section sets out the key findings from the Commission's modelling. More information is provided in Appendix E, which sets out a description of the Commission's modelling approach and detailed modelling results.

***Shifting to ALFs does not necessarily reduce customer payments***

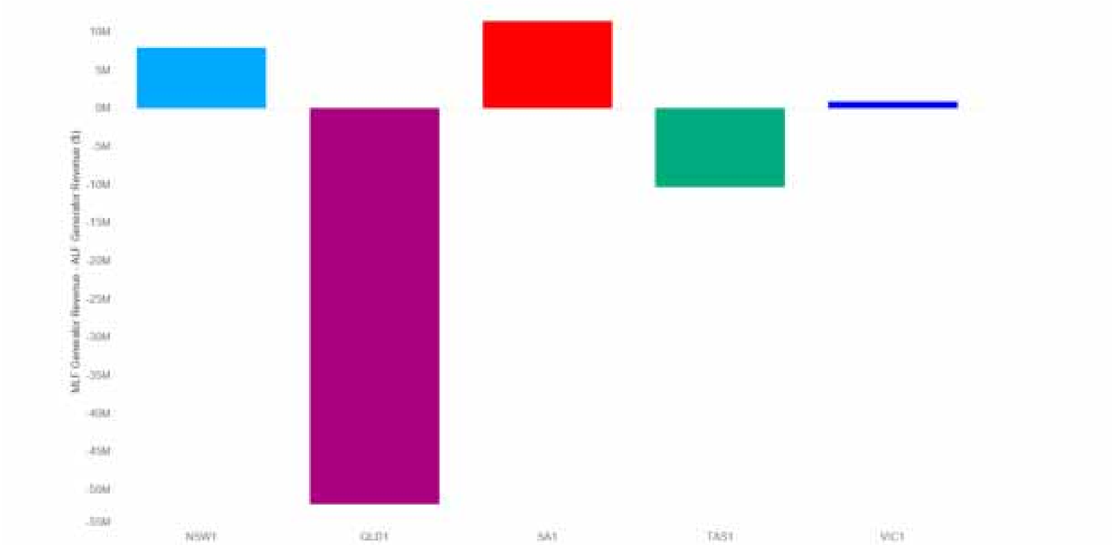
The Commission's analysis indicates that there is no general rule about whether customer payments rise or fall from moving from MLFs to ALFs – the outcome depends on the conditions of dispatch.

Figure 5.11 shows the change in customer payments by region for the scenario where we use POE50 demand for the 2018-19 reference year with historical bids. Regions with negative values indicate that customer payments are higher under ALFs.

Importantly, Queensland has the biggest increase in customer payments from moving to ALFs. Baringa identified Queensland as the region where customers would benefit most from a shift to ALFs.[229] This demonstrates that accounting for the IRSR can change the findings of such a study.

229 CEC supplementary submission to the consultation paper, Baringa report, p. 28.

**Figure 5.11: Change in generator receipts (1 July 2019 to 30 June 2020)**




Source: AEMC
Note: Under an ALF framework, generator receipts would increase in New South Wales, South Australia and Victoria, but decrease in Queensland and Tasmania.

The Commission has modelled 20 different sensitivities to test the robustness of the modelling results to different assumptions. In 18 out of the 20 cases considered, customer payments were lower under MLFs than ALFs.

The Commission therefore concludes that there is no evidence that a move to ALFs necessarily reduces customer payments.

***Shifting to ALFs has a measurable effect on dispatch outcomes***

An additional question that modelling can help to address is the extent to which a shift from MLFs to ALFs would result in a change in dispatch outcomes. Given that MLFs are an inherently more efficient representation of losses, changes in dispatch outcomes arising from a shift to ALFs represent a decrease in efficiency.

Changes in dispatch can occur because of:

- changes in the dispatch order, and
- the need for additional generation to meet additional losses arises from the change in the merit order.

***Measuring the effect on dispatch outcomes – changes in the dispatch order***

It is helpful to explain how moving to ALFs can change the dispatch order. Suppose that there are two generators, G1 and G2, with bids b1 and b2, respectively. If G1 is higher merit than G2 then the relationship in Figure 5.12 holds.

**Figure 5.12: Dispatch order**

$$\frac{b_1}{MLF_1} < \frac{b_2}{MLF_2}$$

Source: AEMC
Note: Where: b1, b2 are the bids of two generators and MLF1 and MLF2 are the MLFs of two generators.

It follows from the equation in Figure 5.12 that a shift to ALFs (approximated by taking the square root of the MLF) can switch the sign of this relationship, showing that the dispatch order can change. Table 5.2 shows a worked example where a generator with a lower raw bid and a lower loss factor displaces a generator with a higher raw bid and a higher loss factor.

**Table 5.2: Impact of a change from MLF to ALF on the dispatch order of dispatch**

| | BID | MLF | ALF | OFFER/MLF | OFFER/ALF |
|---|---|---|---|---|---|
| G1 | $115 | 1 | 1 | $115 | $115 |
| G2 | $100 | 0.8 | 0.89 | $125 | $111.8 |

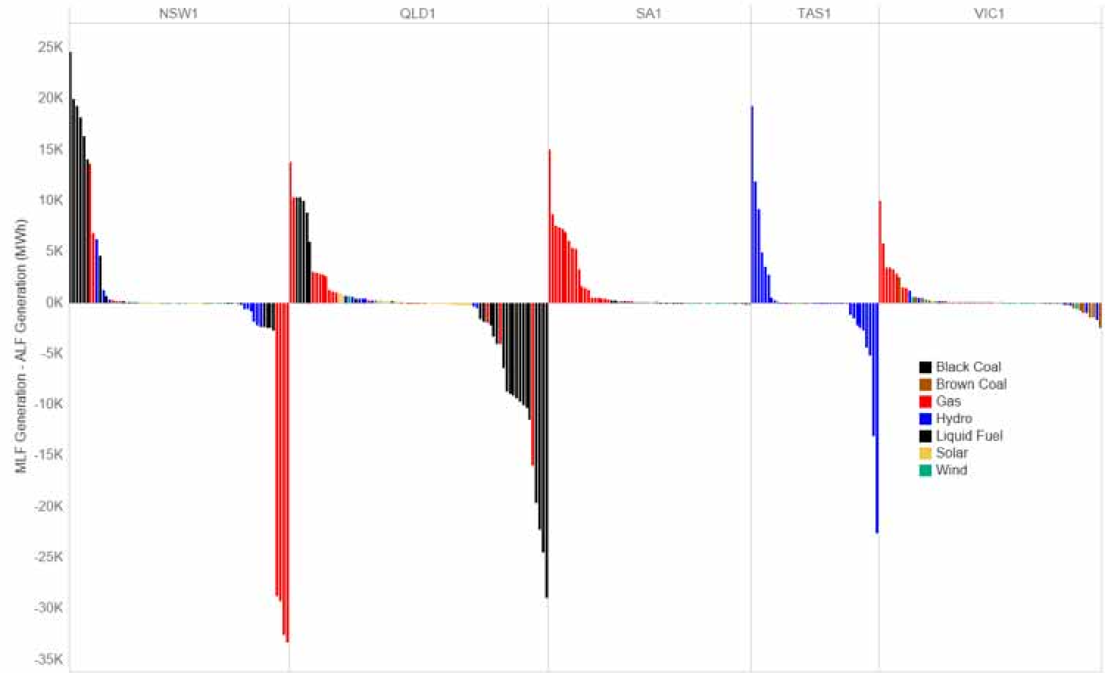
Source: AEMC
Note: Where the Offer is a generator's offer, Offer/MLF is the generator's offer divided by the MLF and Offer/ALF is the generator's offer divided by the ALF.

Changes in the dispatch order manifest in changes in dispatch outcomes. The Commission has examined the changes in modelled dispatch volumes for each generator in the NEM. Figure 5.13 shows the differential in dispatch volumes under ALFs versus MLFs for each generating unit in the NEM. Bars above the horizontal axis indicate units whose output is higher under MLFs; bars below the horizontal axis indicate units whose output is higher under ALFs.

The Commission observes the following:

- The changes in dispatch volumes from moving to ALFs are typically small, with a maximum absolute change in output of 33.3 GWh for Uranquinty Unit 1 versus total modelled output of 216.6 GWh.
- Under ALFs, dispatch from South Australia falls in aggregate because of decreased output from Torrens A, Torrens B and Pelican Point which all sit at the regional reference node.
- Under ALFs, higher generation output is provided by Stanwell power station, which has an MLF of approximately 0.9.
- Under ALFs, there is higher output from Queensland overall.

**Figure 5.13: Changes in dispatch volume of generators (1 July 2019 to 30 June 2020)**




Source: AEMC, see appendix F for full data set.

Note: Bars above the horizontal axis indicate units whose output is higher under MLFs; bars below the horizontal axis indicate units whose output is higher under ALFs.

The Commission has treated these results with caution because they are influenced by the assumed bidding profiles, and different bidding assumptions could affect the results. However, the direction of the changes that we observe in dispatch volumes is consistent with our expectations - that is, under ALFs:

- plants with relatively lower MLFs are dispatched more, and
- plants with relatively higher MLFs are dispatched less.

The change in dispatch outcomes is an indicator of the reduction in efficiency under ALFs. Although the changes are small, they are measurable and significant for some generators.

***Measuring the effect on dispatch outcomes – need for additional generation to meet additional losses***

A challenge in modelling the effect of a shift to ALFs is that there will be an increase in losses, and so an increase in the amount of generation required to meet demand.

The Commission's modelling has used the same demand targets for both the MLFs case and the ALFs case. The consequence of this assumption is that the Commission's modelling:

- underestimates the total generation required, and so the customer payments, under the ALFs case, and
- underestimates the change in dispatch volumes under the ALFs case.

It follows that our modelling tends to underestimate the impacts of moving to ALFs, because we have not been able to account for the increase in generation arising from the increase in losses.

### 5.6.2 Why the Commission has not carried out long-term modelling

The Commission did consider undertaking a major long-term modelling exercise in addition to the first principles' analysis provided as part of its draft rule determination. After exploring this option further , the Commission has decided not to carry out such work. This is because such a model, would be too assumption driven which would impact on the robustness of the modelling insights that could be relied on regarding what the long-term impacts of changing the loss factor methodology may be.

#### Modelling the effects of different loss factor regimes over a multi-year time horizon

As previously discussed, one of the purposes of the MLF framework is to provide a locational signal for new generation investment and operation. In particular, the potential impact of a new generator's output on transmission network losses at different locations.

In addition to a qualitative assessment on what the effects on dispatch and dynamic efficiency might be if the loss factor methodology was changed, the Commission has considered how informative and practical it would be to consider this issue quantitatively. This would be by developing a model to consider the long-term effects of changing from MLFs to ALFs (or some other compression-style loss factor model) on generation investment decisions.

As discussed in more detail below, the two key assumptions underpinning such a model would be:

1. the changes in the WACC between an MLF scenario and the alternative loss factor approach
2. differences in the location of new entrant generation under each of these loss factor scenarios.

Having regard to these assumptions, the Commission's view is that long-term modelling would not form a key basis on which to make a decision with respect to this rule change process because:

- There are a significantly large number of arbitrary assumptions that would need to be made about future demand, future new entrant supply, and the location of demand and new supply, under each of the loss factor scenarios. In order to expose differences between the likely generation expansion paths under each of the two loss factor scenarios, the modelling would need to simulate at least five to 10 years into the future. This would make estimates of costs and benefits highly sensitive to the assumptions made, particularly the two key assumptions noted above.
- Modelling potential future physical losses under each of the scenarios is a complex and complicated exercise. The revealed errors in market participants' longer-term forecasts of

> MLFs provides a cautionary, and instructive, tale for the issues associated with potential longer-term modelling of the impacts of different loss factor methodologies.

The Commission's view is that long-term modelling is therefore unlikely to deliver robust conclusions on which to make a decision in the context of the NEO, due to the large number of assumptions required. Modelling the potential longer-term impacts of a change to loss factor methodology would, in effect, require two sets of models equivalent in complexity to AEMO's Integrated System Plan (one set of models for each loss factor methodology). This would take many months to do, delaying publication of the final rule determination for this process by several months.

### 5.6.3 Efficiency and risk allocation

In the draft rule determination, the Commission applied an assessment framework to evaluate if an ALF approach would be likely to better contribute to the achievement of the NEO. Some stakeholders indicated in their submissions that they were concerned that the Commission, in its draft rule determination, did not properly consider the NEO.[230]

The Commission has considered the recent submissions and comments made at the pre-final rule determination hearing in combination with the results of the quantitative analysis it has carried out. The discussion below relates to:

- investment efficency
- operational effciiency
- risk allocation.

#### Efficient investment

In its draft rule determination, the Commission concluded that ALFs, and other forms of compressed loss factors, are likely to induce additional investment in locations with relatively weak transmission infrastructure. In the Commission's view, this would be likely to result in increasing losses and congestion for the transmission network in the long run. Such poor locational decisions were expected to arise due to the diminished locational signal provided under compressed loss factor methodologies.

Incorporating these considerations into a long-term model would result in system costs and consumer prices in an alternative loss factor scenario (such as ALFs) being higher than in an MLF scenario. For example, the Commission noted in the draft rule determination that:[231]

> A change from marginal loss factors to average loss factors will therefore have an effect on dynamic efficiency. Dampening the locational signals would be likely to lead to more investment in parts of the power system with high losses. Over time, this would increase the amount of losses, and so the total dispatch cost. Ultimately, consumers would pay more for electricity to cover the cost of the additional electrical loses occurring as, overall, more electricity would have to be generated to meet the

230 CEIG submission to the draft determination, p. 7.

231 AEMC, Draft Rule determination Transmission Loss factors, 14 November 2019, p. 55.

same level of demand.

However, some stakeholders have argued that MLF volatility results in an increase in the cost of capital of generation investments which directly translates into higher energy prices (see section 5.6.3).

Other stakeholders, submitted that the draft rule determination was correct to maintain an MLF framework, as average loss factors:[232]

- are inconsistent with the concept of marginal pricing and could result in inefficient dispatch of generation (see section 5.6.1).
- would dampen locational signals, leading to inefficient locational decisions.

As discussed in section 5.6.4, the Commission recognises the cost of capital could be lower under a compressed loss factor regime than under an MLF regime. However, the cost of capital is one of many considerations the Commission is taking into account when determining whether the proposed rule change will or is likely to contribute to the achievement of the NEO. In particular, another consideration is the effect of the proposed rule on new-entrant generators' locational decisions.

While the Commission understands that currently planned investments in generation assets are likely to require a higher cost of capital due to MLF volatility, it has to weigh this against the potential costs of long term locational and dynamic inefficiencies resulting from a change to an ALF methodology. As a result, the Commission's assessment is that:

- an ALF methodology is likely to result in less efficient locational decisions for generation assets
- technological change in the medium to long-term, for example battery storage, is likely to reduce MLF volatility for generators
- on balance it is difficult to estimate the impact on consumers, but it is likely that prices under ALFs could increase as market-wide locational inefficiencies, dynamic inefficiencies and dispatch inefficiencies compound and are likely to outweigh the savings likely to be realised by consumers as a consequence of changes in the cost of capital experienced by some individual generators.

For these reasons, after taking into account stakeholder comments in submissions, the pre-determination hearing and other meetings regarding investment efficiencies, and consistent with its draft rule determination, the Commission has decided the proposed change to use average loss factors in the NEM will not, or be unlikely to, support efficient investment for the long-term interest of consumers of electricity (and in that respect, is unlikely to contribute to the achievement of the NEO).

#### Operational efficiency

In its draft rule determination the Commission concluded that ALFs, and other forms of compressed loss factors have the potential to change the dispatch order of generation. The

232 Origin submission to the draft determination, p. 1.

Commission noted that under an ALF approach, generators with higher losses could potentially be dispatched ahead of generators with lower losses but higher SRMCs. In its draft rule determination the Commission concluded that:[233]

> While the ALF approach might provide more certainty to some investors, it comes at the expense of the potentially more efficient generators which do not get dispatched. This could ultimately result in higher electricity prices.

In its submission to the draft rule determination and at the public hearing, CEIG argued that the Commission dismissed the conclusions of the modelling provided by Baringa and instead relied on a chart reflecting a stylised example on the impact of using an ALF framework on dispatch efficiency.[234]

However, other stakeholders agreed with the Commission's draft rule determination. For example, the AEC submitted that it considers that marginal loss pricing remains an essential part of dispatch efficiency as two competing generators at extreme ends of the NEM can have a marginal loss equivalent factor between them as high as 2:1.[235]

The Commission undertook further quantitative analysis to test if the ALF approach would contribute to the achievement of the NEO. This analysis was described above in section 5.6.1 and concluded, among other things, that:

- There is a measurable change in NEM dispatch outcomes associated with moving to ALFs.
- However, the modelling and analysis underestimates the dispatch costs of the ALFs scenario, because the additional generation required to meet the higher level of losses under this scenario cannot readily be modelled.

For these reasons, and the reasons set out in the draft rule determination, the Commission has decided that implementation of an average loss factor methodology would not provide operational efficiencies in the long-term interests of consumers (and in that respect, is unlikely to contribute to the achievement of the NEO).

#### Risk allocation

In its draft rule determination the Commission concluded that ALFs, and other forms of compressed loss factors have the potential to transfer risk from generators to end-consumers who are the party least able to manage loss factor risk. In its draft rule determination the Commission concluded that:[236]

> A change from marginal to average loss factors would involve a transfer of risk from investors in new generation assets to consumers. However, consumers are not involved in the investment decision-making processes for new generation assets, and they would not be able to enter into long-term power purchasing agreements. Consequently, consumers are, in the Commission's view, the party least able to

233 AEMC, Draft Rule determination Transmission Loss factors, 14 November 2019, p. 55.

234 CEIG submission to the draft determination, p. 4.

235 AEC submission to the draft determination, p. 2.

236 AEMC draft rule determination, Transmission Loss factors, 14 November 2019, p. 55.

> manage loss factor uncertainty and the resulting impact on consumer prices.

As noted above in this chapter, stakeholders have argued that the Commission's focus on risk allocation as a zero-sum game limited to transfers between investors and customers is flawed. CEIG commented that the AEMC has the ability to reduce and remove unnecessary risks emerging from the market design that creates a more stable and competitive investment environment and improves long-term customer outcomes.[237]

Other stakeholders agreed with the Commission's assessment in the draft rule determination that an ALF would result in a decrease in the cost of capital by shifting risk from generators to customers who are the least well-placed to manage loss factor risk. For example, the AEC submitted that:[238]

> Financial exposure to them can be moved downstream as proposed in the Rule, with upstream risk commensurately lessened, but the total risk across the industry would actually increase as it has simply been moved on to parties uninvolved in its causation.

Nevertheless, no new information in regard to the Commission's assessment of the allocation of risk has been provided to the Commission after the publication of the draft rule determination.

As outlined above and in the draft rule determination, the Commission's assessment of the impact of using ALFs rather than MLFs is that it would shift risk from generators to consumers.

Stakeholder submissions (and presentations at the pre-final rule determination hearing) indicate that some investors in renewable generation assets are assuming that the additional costs to consumers associated with that risk transfer are less than the resulting savings attributable to a lowering of the cost of capital that they would experience.

However, the Commission's quantitative analysis in section 5.6.1 of this final rule determination indicates that it is unclear whether there will be any reductions in costs to consumers attributable to a change to ALFs. This wasn't clear in the Baringa analysis referred to by some stakeholders because its modelling did not take into account the impact of changing the loss factor methodology on the IRSR.

As a result, and consistent with the draft rule determination, the Commission has concluded that changing to an ALF methodology for transmission loss factors will be detrimental to the long-term interests of consumers having regard to the impact on risk allocation (and in that respect, is unlikely to contribute to the achievement of the NEO).

#### Impacts on load

The Commission notes the submission received from the CEC that the draft rule determination did not consider the impact of different loss factor methodologies on load, or

237 CEIG submission to the draft determination, p. 4.

238 AEC submission to the draft determination, p. 2.

electricity customers.[239] In response, the Commission notes that the draft rule determination specifically considered load as part of the Commission's consideration of the issues raised by Central Irrigation Trust.[240] Generally, the Commission notes that the loss factor impact on load is the opposite of the loss factor impact on generation, that is:

- higher loss factors results in higher costs to load
- lower loss factors result in lower costs to load.

This issue is also dealt with in this final rule determination in Chapter 7.

### 5.6.4 Impacts on the cost of capital

The Commission's draft rule determination noted that moving to ALFs or another compressed loss factor methodology could provide more stable and predictable loss factors, reducing revenue volatility and lowering the cost of capital for investors in some generation assets. It also noted that, while potentially reducing the cost of capital, it is likely that an ALF methodology would be shift risk from the party best placed to manage it (investors in new generation) to those who are least able to manage this risk (consumers), resulting in inefficiencies leading to higher electricity costs.

Some stakeholders have argued that the Commission should reconsider its cost of capital analysis and provide the results of the investor survey conducted by the Commission. [241] Other stakeholders submitted that MLF volatility reflects a broader set of generation and transmission issues beyond the scope of this rule change process.[242]

#### Results of the investor survey

To better understand the potential impacts from changing to a compressed loss factor regime, the Commission included a question on transmission loss factors in a general survey of generation sector investors and market participants. This survey considered a broad range of issues including:

- trends in the availability and cost of debt and equity financing over the preceding 12 months
- extent of any change in gearing levels over the past 12 months and reasons for any changes
- the influence of each of the top 3 entry barriers on changes in the cost of debt and equity financing, and
- trends in power purchasing agreements (PPAs) and estimates of the reasonable spread for large-scale renewable and non-renewable projects.

The survey also included the prioritising and ranking of different factors commonly cited as barriers to entry into the generation sector. The top three issues identified by survey participants were (in decreasing order of importance):

239 CEC submission to the draft determination, p. 2.

240 AEMC, transmission loss factors draft rule determination, 14 November 2019.

241 Submissions to the draft determination: CEIG, p. 5; CEC, p. 2.

242 ENA submission to the draft determination, p. 2.

1. Generator connection requirements, that is, the increasing time taken to both connect generators to the NEM and for these generators to be allowed to generate its full output.
2. Insufficient network capacity relative to the generation capacity being installed at various locations in the grid, that is, for some participants, the main issue here was the resulting higher physical losses (and in turn higher MLFs); for others, the main issue was the increase in export (output) congestion.
3. the increased imposition of system security-related output constraints. In recent times, several generators located in north-west Victoria and western New South Wales, have had their output constrained down by AEMO due to concerns about inadequate system strength in those areas.

Survey responses were sought from members of the CEC and the AEC. Of the 170 members of either the CEC or the AEC (but not both), asked, 15 responded to the survey. Three other organisations which are not  members of the AEC nor the CEC, also responded to the survey, providing a total of 18 respondents.[243]

Of the 16 questions, one question was in relation to transmission loss factors specifically. This question asked participants about the extent to which changing to a compressed loss factor regime could impact the WACC for new renewable and non-renewable projects.

The consensus among the 16 respondents who answered this question (two of the 18 respondents did not answer this question) was that a compressed loss factor regime would decrease WACCs by between 100-150 basis points per year compared to WACCs under an MLF framework. This range reflects the range of point estimates provided by each of the 16 respondents.[244]

**The cost of capital of existing generators**

The Commission notes Enel Green Power's comment that exposing a generator to ongoing volatile MLFs after plant has been built increases its costs with little likely improvement in efficiency.[245] It acknowledges that some other owners of generation assets may hold similar views.

In response, the Commission considers that this issue is attributable to the open access regime of the NEM rather than the loss factor methodology specifically. It notes that while changing the loss factor methodology has the potential to smooth out revenue volatility for generator owners, it cannot address the root causes of loss factor volatility such as transmission network congestion. It also notes its earlier comments, that there is some ability of owners of generation assets to manage this revenue volatility by holding a portfolio of assets and/or a portfolio of contract arrangements. In addition, that shifting the risk of revenue volatility from generators to consumers is to shift this risk to parties that are not able to manage the risk at all.

243 It is important to note that about half of the 150 members of the Clean Energy Council are neither generation developers nor investors,these members include, for example, solar installers and equipment manufacturers), and therefore would not be expected to respond to the AEMC's survey. Therefore, the effective response rate of 19 per cent.

244 Further details on the responses are not reportable. The Commission appreciates the confidential and commercially sensitive information provided by the survey respondents.

245 Enel Green Power submission to the draft determination, p. 1.

The cost of capital is one of the many issues the Commission takes into account when assessing whether a rule change request will or is likely to contribute to the achievement of the NEO. Consistent with its draft rule determination, the Commission considers that:

- loss factor volatility can cause increases in the cost of capital
- increases in the WACC of existing generators over the life of the asset are most likely caused by the nature of an open access regime, rather than the loss factor methodology
- there is some ability of generator owners to manage revenue volatility compared to consumers.

## 5.7 Final rule determination

The additional analysis undertaken as part of this final rule determination has confirmed for the Commission that an ALF methodology for determining loss factors is unlikely to better contribute to the achievement of the NEO than the approach in the final rule (which retains an MLF framework).

In particular, the Commission's additional analysis has confirmed that implementing an ALF approach to determining transmission loss factors would be likely to result in:

- a change in the generator dispatch order of dispatch resulting in generators with relatively higher physical losses and/or SRMCs being dispatched
- lower spot prices than under an MLF approach, and
- an uncertain effect on generator payments.

Consistent with its draft rule determination, the Commission has concluded the following:

- Using average loss factors would be a move away from the economic framework of the NEM based on marginal pricing and could result in inefficient dispatch.
- Average loss factors would provide a dampened locational signal compared to marginal loss factors. This is likely to increase losses and congestion as new generators will be likely to locate in less efficient locations.
- Moving to an average methodology could provide more stable and predictable loss factor values. This would help reduce revenue volatility and lower the cost of capital for investors in some generation assets.
- However, an average loss factor methodology would also shift risk from the party best placed to manage it (investors in new generation assets) to consumers (who are least able to manage loss factor risk) resulting in further inefficiencies leading to higher costs for consumers.
- Average loss factors are likely to decrease the loss factors of generators with relatively high MLFs and increase loss factors of generators with relatively low MLFs.

For the above reasons, the Commission considers that the use of the proposed average loss factor methodology in the NEM would not represent an improvement in the determination of transmission loss factors and consequently would be unlikely to be in the long term interest of electricity consumers. Accordingly, the Commission is satisfied that, having regard to the issues raised by Adani Renewables in its rule change request, the final rule will, or is likely to, better contribute to the achievement of the NEO than the rule proposed in that request.

# 6 AEMO'S IMPROVEMENTS TO MARGINAL LOSS FACTORS

This chapter sets out and discusses the changes to the current MLF rules as suggested by AEMO in its submissions to the consultation paper and draft rule determination. It also sets out stakeholder submissions in response to the draft rule determination as well as the Commission's analysis in relation to improvements to marginal loss factors.

In brief, the Commission has concluded that these suggested changes improve the MLF framework and will, or are likely to, contribute to the achievement of the NEO. These amendments to the NER form the basis of the final rule.

## 6.1 AEMO's suggested rule changes

AEMO undertakes its own consultation process on the loss factor methodology with stakeholders.[246] It submitted that it will carry out a formal consultation on the methodology for determining MLFs to ensure that it remains fit for purpose after the AEMC's rule change process has been finalised.[247]

To provide greater flexibility to modify the calculation of MLFs as part of its own consultation process with stakeholders, AEMO identified three changes to the NER which, in its opinion, could assist it in providing more transparency on loss factor changes to help market participants better anticipate and manage changes in MLFs.

These changes to the NER are:[248]

1. Clause 3.6.1(d)(5) of the NER requires AEMO to use regression analysis to reflect inter-regional losses between nodes. AEMO submitted that flexibility to consult with stakeholders on techniques that are alternatives to regression analysis to reflect inter-regional losses could produce more optimal results. It therefore suggested that the relevant clause be removed.
2. Clause 3.6.2(e)(4) of the NER currently requires the MLF calculation to be performed on a 30-minute 'trading interval' basis. This means over 17,500 individual calculations are required to determine the MLFs each year. AEMO suggested that the 30-minute trading interval requirement be reconsidered as calculations using greater time intervals (for example, four hourly intervals) may simplify the calculation process and better enable stakeholders to understand the loss factor calculations.
3. Clause 3.6.2(e)(6) of the NER requires that AEMO treat MNSPs as invariant in the MLF methodology. AEMO submitted that changing generation patterns between regions, for example due to new entrants, may require load balancing in the calculation. If this is the case, treating the MNSP flow as invariant may no longer be practical or appropriate. AEMO suggested that it may improve the accuracy of its modelling if it is able to better

246 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 13.

247 AEMO submission to the consultation paper, p. 1.

248 AEMO submission to the consultation paper, p. 5.

reflect actual flows and treat MNSPs (the only MNSP at present is Basslink) in a manner similar to other assets. AEMO therefore suggested that this clause be removed.

These changes, in AEMO's opinion, would allow it to work with stakeholders through formal consultation to improve the accuracy the loss factor calculation.[249]

## 6.2 Draft rule determination

In the draft rule determination the Commission assessed that making the rule changes suggested by AEMO as opposed to not making any amendments to the NER would, or would be likely to, contribute to the achievement of the NEO. The draft rule amendments provide additional benefits to market participants with respect to simpler and more flexible calculations as well as less complex models.

As a result, the draft rule amendments:

- removed the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- removed the requirement that MLF values must be based on a period of 30 minutes to allow other time periods to be used as the basis for calculating MLF values
- removed the requirement that flows in network elements that solely or principally provide market network services be treated as invariant in the calculation of MLFs so that AEMO would be able to forecast variable MNSP behaviour in its modelling.

In addition to these amendments, the draft rule also replaced "transmission loss factors" with "intra-regional loss factors" in clauses 3.6.2(b), (g) and (h) and Chapter 10 (for the terms "NMI Standing Data" and "virtual transmission node") of the NER. This was done to ensure consistency of terminology in the NER and did not change the meaning of those terms.

### 6.2.1 Removing the requirement to use regression analysis

Clause 3.6.1(d)(5) of the NER specifies that to determine the inter-regional loss factor equations, AEMO must apply regression analysis to load and generation data to determine the variables that have a significant effect on marginal electrical energy losses and the relationships between those variables and the marginal electrical energy losses.

AEMO requested that clause 3.6.1(d)(5) of the NER be removed to allow it to use calculation methodologies other than regression analysis in determining inter-regional loss factor equations.  However, it did not identify any specific alternatives to regression analysis that could be adopted.

In its draft rule determination, the Commission stated that it agreed with AEMO's suggestion as it would allow AEMO to consider alternative calculation methodologies to calculate the MLF as part of its own consultation with stakeholders.

249 AEMO submission to the consultation paper, p. 5.

The Commission noted that this change would still require AEMO to use an MLF methodology but it should provide more flexibility in the way the MLF values can be calculated. The removal of the requirement to use regression analysis would allow AEMO to continue using regression analysis until it has developed, following consultation, another methodology producing more accurate results. Making a change to clause 3.6.1(d)(5) of the NER now would provide AEMO with future flexibility and enables the employment of a new calculation method without any further rule change process.

The Commission concluded in its draft rule determination that making this change to the NER would, or would be likely to, contribute to the achievement of the NEO as it would provide AEMO with the additional flexibility to implement any other, more efficient calculation methodology, should such a calculation methodology become available in the future.

### 6.2.2 Changing the 30-minute interval requirement

Clause 3.6.2(e)(2) of the NER requires the MLF methodology implemented by AEMO to enable an MLF value to:

> as closely as is reasonably practicable, describe the average of the *marginal electrical energy losses* for electricity transmitted between a *transmission network connection point* and the *regional reference node* in the same *region* for each *trading interval* of the *financial year* in which the *intra-regional loss factor* applies.

Relatedly, clause 3.6.2(e)(4) of the NER requires AEMO to calculate an MLF "for each *transmission network connection point* for each *trading interval* in the *financial year*". A NEM trading interval is currently 30 minutes.[250] This requirement means that a significant amount of calculation is required to produce each MLF value at each transmission connection point. This calculation complexity may mean that MLFs are difficult to reproduce, understand or estimate by market participants.

In its draft rule determination, the Commission noted that AEMO had indicated that the MLF calculation process could be made simpler and more likely to be replicable, without materially losing the level of accuracy of the MLF values, by allowing it to use less frequent data in the calculations.  For example, AEMO may find that calculating MLFs on four hourly interval data may be sufficiently accurate but require fewer calculations and improve market participants' understanding of the methodology. Such an approach would still need to satisfy the requirement of clause 3.6.2(e)(2) of the NER to be as representative of the physical electrical losses in each trading interval as closely as reasonably practicable.

The Commission considered that this suggested change to clause 3.6.2(e)(4) of the NER had the potential to increase transparency and predictability of MLF values and in doing so, contribute to better investment decision-making and operations in the generation sector. For

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250 Clause 3.6.2(e)(4) of the NER will be amended in the future to require the use of data for each 30-minute period (or a shorter period as specified in the methodology). However, the final rule will remove this phrase entirely, following such amendment taking effect, to allow for longer time periods to be used in the methodology. See AEMC, *National Electricity Amendment (Five minute settlement and global settlement implementation amendments) Rule 2019, No. 7*, 8 August 2019.

these reasons, the suggested change was considered to be likely to contribute to the achievement of the NEO and was included in the draft rule.

### 6.2.3 Removing the requirement to treat MNSPs as invariant in the MLF methodology

In its submission AEMO also requested the removal of clause 3.6.2(e)(6) of the NER. This clause requires AEMO to treat MNSPs as invariant, or fixed, in the MLF methodology. The clause also notes that the MLF methodology does not seek to calculate marginal losses for MNSPs.

The draft rule determination acknowledged that the reason the Rules requires MNSPs to be treated as invariant is that is MNSPs bid strategically like a generator to maximise revenue. This would be difficult to model in the minimum extrapolation method because offering into one region also means bidding into the other region relevant to the MNSP. As a result, to aid modelling, the NER required MNSPs be treated as invariant so that the flows assumed in the calculations would follow historical flow patterns.

However, the Commission observed that market conditions have changed sufficiently to consider removing the requirement in clause 3.6.2(e)(6) of the NER. This would allow AEMO to use other assumptions and information in modelling the flows associated with MNSPs if it finds that an alternative approach better reflects actual behaviour and is still consistent with the MLF methodology. As BassLink is currently the only MNSP in the NEM, an alternative approach to the fixed flow assumption in the modelling for MLFs may be achievable.

## 6.3 Public hearing

The draft rule amendments to the NER were not discussed by presenters at the pre-final determination hearing.

## 6.4 Stakeholder views on the draft rule determination

A number of stakeholders simply stated that they supported the Commission's draft rule amendments to provide AEMO with more flexibility in the way the MLF values can be calculated.[251]

However, both EnergyAustralia and Stanwell expressed concern about the level of information provided by AEMO to support its suggested changes. Stanwell stated that:[252]

> it is incumbent on AEMO to document how any proposed alternative technique would produce more optimal TLF results.

On the removal of the requirement to use regression analysis in determining loss factors, EnergyAustralia supported this change, provided participants have clarity and confidence in any changes. EnergyAustralia submitted that:[253]

251 Submissions to the draft determination: ACCC, p. 2; AEC, p. 1; AGL, p. 1; Infigen, p. 2; Origin, p. 2; AER, p. 3; Department for Energy and Mining SA, p. 1; TasNetworks, p. 2; Tilt Renewables, p. 1; PIAC, p. 1.

252 Stanwell submission to the draft determination, p. 2.

253 EnergyAustralia submission to the draft determination, p. 1.

> It is important that stakeholders have adequate opportunity to engage with AEMO and assess any future proposed changes. There should be a clear requirement for this as changes in MLF methodology, while beneficial overall, could have unforeseen financial impacts on participants that need to be clearly understood to minimise the impact of the change. It is also important that methodologies are not changed too frequently as this could create uncertainty within the market. AEMO should be required to quantifiably demonstrate the improved accuracy of any change in methodology during a consultation process.

The draft rule also changed the requirements on AEMO using a 30-minute interval in its determination of MLF values. EnergyAustralia and Stanwell expressed concern about the implications of this change.

Specifically, EnergyAustralia submitted that it "...question[s] the merits of the proposal to move from half-hourly intervals to four-hourly intervals." It also noted that "AEMO has not provided any numerical evidence" for the change and that "averaging over multiple trading intervals will service to dull accuracy".[254]

AEMO submitted that clause 3.6.2(e)(6) (which relate to the requirement to treat network flows that solely or principally provide market network services as invariant) ) be deleted altogether as they considered that aspect of the draft rule (which clarified that such flows are not required to be treated as invariant, rather than deleting the principle altogether) it to be "unnecessary and potentially misleading".[255] AEMO further submitted that if the clause was not deleted the Commissions should consider expanding "its application to all ‘independently controllable two-terminal links’ and clarify the principle as an assumption that there are no marginal electrical energy losses within an independently controllable two-terminal link."[256]

## 6.5 Final rule determination assessment

The Commission has assessed stakeholder submissions to the draft rule determination including the changes sought by AEMO to the draft rule. The Commission considers that only one amendment needs to be made to the draft rule. Its analysis is set out below.

In response to some concern that AEMO has not supported its rule amendment suggestions with sufficient information, the Commission acknowledges that the information provided in this instance is brief. However, in the context of this rule change process, and having regard to the nature of the suggested amendments, the Commission is satisfied that AEMO has provided it with sufficient explanation in both its submissions and in discussions.

### 6.5.1 Removal of clause 3.6.2(e)(6) of the NER

The final rule removes clause 3.6.2(e)(6) of the NER which currently relates to the treatment of MNSPs as invariant in the determination of transmission loss factors.

254 EnergyAustralia submission to the draft determination, p. 2.

255 AEMO submission to the draft determination, p. 3.

256 AEMO submission to the draft determination, p. 3.

In its analysis and reasoning to the draft rule determination for the amendment to clause 3.6.2(e)(6), the Commission noted that it understood the reason why this rule requires MNSPs to be treated as invariant is that MNSPs bid strategically like a generator to maximise revenue. This would be difficult to model in the minimum extrapolation method because offering into one region also means bidding into the other region relevant to the MNSP. As a result, to aid modelling, the NER required MNSPs be treated as invariant so that the flows assumed in the calculations would follow historical flow patterns.

However, the Commission noted that market conditions have sufficiently changed to consider removing the requirement in clause 3.6.2(e)(6) of the NER. This change would allow AEMO to use other assumptions and information in modelling the flows associated with MNSPs if it finds that an alternative approach better reflects actual behaviour and is still consistent with the MLF methodology.

The Commission notes that the draft rule amended clause 3.6.2(e)(6), rather than deleting it entirely, by clarifying that such network flows need not be treated as invariant as part of the calculations in the MLF methodology. After receiving AEMO's submission to the draft rule determination and re-examining the practical effect of the draft rule, the Commission considers that the clarification is unnecessary, and has effectively made that sub-clause redundant. Consequently, it has been deleted in the final rule.

Removing clause 3.6.2(e)(6) does not have any residual practical or technical impacts in accounting for losses in the NEM. Calculating marginal losses within the network comprising an MNSP is of no value as AEMO calculates the TLFs for actual connection points not within an MNSP. It does not consider that the alternative solution suggested by AEMO, to expand the application of clause 3.6.2(e)(6) is necessary or appropriate.

### 6.5.2 Other amendments to the NER

The amendments reflected in the draft rule do not require AEMO to change the current mechanisms within the MLF calculation methodology but instead allows AEMO the flexibility to implement changes that may improve flexibility and simplicity of the calculation mechanism. This does not preclude AEMO from having to engage with stakeholders on any change to the calculation that may be made in the future. Any changes AEMO propose to implement to the MLF calculation methodology must be carried out in consultation with stakeholders in accordance with the *Rules consultation procedures* as found in, Part F, Chapter 8 of the NER.

Both EnergyAustralia and Stanwell raised concerns with the draft rule. The overall premise of their concerns were that if these amendments were to come into effect there is no prescription for AEMO to properly consult with stakeholders on any proposed changes. However, as stipulated in the *Rules consultation procedures* any changes to the methodology will have to be consulted upon with stakeholders.[257]

257 Clauses 3.6.1(c) and 3.6.2(d) of the NER.

The purpose of these amendments to the NER is to allow debate and analysis to occur in the context of improving the forward-looking MLF consultation, without the need for a rule change.

The amendments to the NER facilitates the consideration of potential simplification in the context of other assumptions used in the forward-looking loss factor process. This may include generation projection for the MLF application year, which can have a far greater impact on MLF calculations and are not specified in the rules. Possibly reducing the number of intervals may allow AEMO to focus on these items more, and may potentially increase the overall accuracy of the calculation.

The Commission considers that all three changes will, or are likely to, contribute to the achievement of the NEO and provide additional benefits to market participants with respect to implementing a simpler and more flexible calculation that facilitates the ability to produce less complex models.

## 6.6 Final rule determination

In making the final rule, the Commission has made one amendment to the draft rule; deletion of clause 3.6.2(e)(6) of the NER.

As a result, the final rule will:

- remove the requirement that the inter-regional loss factors must be calculated using a regression analysis, enabling AEMO and stakeholders to consider and test the performance of alternative calculation techniques
- remove the requirement that MLF values must be based on a period of 30 minutes to allow other time periods to be used as the basis for calculating MLF values
- delete the principle for MNSPs be treated as invariant in the calculation of MLFs so that AEMO would be able to forecast variable MNSP behaviour in its modelling.

In addition to these amendments, the final rule also replaces "transmission loss factors" with "intra-regional loss factors" in clauses 3.6.2(b), (g) and (h) and Chapter 10 (for the terms "NMI Standing Data" and "virtual transmission node") of the NER. This was done to ensure consistency of terminology in the NER and does not change the meaning of those terms.

The Commission is satisfied that the more preferable rule will, or is likely to, better contribute to the achievement of the NEO than the solutions proposed by Adani Renewables in their rule change requests. The more preferable rule will do this through increasing transparency and efficiency of the MLF calculation process, for the reasons set out n part 6.5 of this Chapter.

# 7 OTHER IMPROVEMENTS TO MARGINAL LOSS FACTORS

As noted in the consultation paper, there are other possible actions that could be taken to address stakeholder concerns about the current volatility in MLFs. Some of these actions do not require amendments to the NER.

Many stakeholders commented on the measures included in the consultation paper. Some stakeholders provided alternative measures they thought could provide relief from loss factor volatility.

This chapter summarises additional stakeholder comments on other improvements to the loss factor methodology and provides the Commission's analysis and final determination on:

- the measures the Commission identified in the consultation paper
- the alternative methodologies and measures suggested by stakeholders in their submissions.

## 7.1 More frequent publication of MLFs

Under clause 3.6.1(f1) of the NER, AEMO is required to publish inter-regional loss factor equations by 1 April for use over the 12-months commencing 1 July. As discussed in the public workshop on 4 July 2019, these requirements do not prevent AEMO publishing forecast MLF values at other times during the 12-month period for information purposes. However, more frequent mandatory publication of MLF values for the purpose of operating the NEM would require amendments to the NER. Consequently, the consultation paper sought feedback on how often loss factors should be calculated. In particular:[258]

- the current arrangements of determining and publishing the MLFs once a year
- if the potential benefits of more frequently determined and published MLFs would be likely to outweigh the costs
- the appropriate frequency for determining and publishing MLFs.

### 7.1.1 Stakeholder views on the request

Stakeholder submissions made in response to the consultation paper commented that more frequent publication of MLFs for market information could go some way in addressing MLF uncertainty. Some stakeholders went further, suggesting that AEMO should publish and use MLFs more frequently. Both options are discussed below.

#### More frequent publication of MLFs for information only

Stakeholders suggested that a more frequent publication of forecast MLFs for information purposes, could greatly reduce the current level of uncertainty arising out of loss factor volatility.[259]

258 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, pp. 17-18.

259 For example, First Solar submission to the consultation paper, p. 8.

AEMO stated that it intended to publish quarterly indicative MLF updates (for all regions in the NEM) which will provide trends of MLFs in the current year.[260] AEMO expected to base these quarterly indicative MLFs on the most recent information available, for example changes to the generator information page.[261] It published the first of these reports on 1 November 2019.[262]

Mondo submitted that more requirements could be placed on AEMO to improve the level of data and information available to participants. Once the ex-ante static yearly MLF has been applied, Mondo suggested that it would be useful if AEMO were to dynamically calculate and publish (but not use) in real time the dynamic MLF for each connection point. This would assist participants in understanding how a dynamic MLF would vary from their static yearly ex-ante MLF. As a final step, Mondo stated that it would also be useful if at the conclusion of the year, AEMO used the dynamically calculated and published half hourly MLFs to determine ex-post, what a static MLF would have been for each connection point using actual data rather than the forecast data used for the ex-ante calculation.[263]

ENA submitted that while it preferred a move to dynamic loss factors, in the meantime, more frequent updating would be an improvement.[264] The CEC also expressed support for AEMO's plan to publish more frequent guidance on MLFs.[265]

Stakeholders also noted that in addition to more frequent publication of loss factors, implementation of the rule change on the transparency of new projects will be able to provide additional certainty for generation investments.[266]

#### More frequent publication and use of MLFs

In its submission to the consultation paper, MEA Group suggested that improvement to the current regime should focus on how often MLFs are calculated and the possible introduction of applying MLFs for different periods (for example, peak and off-peak periods).[267]

Similarly, EPSDD stated that the NER should be amended to remove the requirement that AEMO produce loss factors that apply for a whole financial year. According to EPSDD, AEMO should instead be required to publish one or more loss factors, and the associated time period(s) in which they apply, for the next financial year. This should require AEMO to ensure each connection point has a loss factor in place for the whole financial year. In EPSDD's opinion, this would allow, but not require, AEMO to implement dynamic loss factors. It would enable AEMO to strike an appropriate balance between the simplicity of having a small number of loss factors, with the accuracy of a larger number. This may result in loss factors

260 AEMO submission to the consultation paper. p. 1 and workshop presentation slides, Brisbane, 4 July 2019.
261 AEMO submission to the consultation paper, p. 4.
262 AEMO, *Indicative marginal loss factors: FY 2020-21*, November 2019.
263 Mondo submission to the consultation paper, p. 10.
264 ENA submission to the consultation paper, pp. 5-6.
265 CEC submission to the consultation paper, p. 2.
266 Submissions to the consultation paper: CEC, p. 2; AGL, p.2.
267 MEA Group submission to the consultation paper, p. 2.

applying for broad time periods such as "winter nights" or "summer days" and would not necessarily require a separate loss factor for every five minute interval.[268]

### 7.1.2 Draft rule determination

In its draft rule determination, the Commission commented that the additional publication of loss factors for information purposes by AEMO should improve the predictability and certainty in regard to MLF changes for market participants in the NEM. It considered it likely that:

- a more frequent publication of loss factors on a quarterly basis, for information only, has the potential to provide valuable information to prospective investors and owners of generation assets
- a more frequent publication of loss factors, for information only, would not affect the efficiency of the operation of the NEM
- while creating some additional work for AEMO to resource, this is likely to be outweighed by the benefit of the additional information provided to the market
- more frequent MLF information would work in conjunction with the new rules on the transparency of new projects to enable market participants to make more fully informed decisions on investment in and operation of generators.[269]

For these reasons, the Commission supported AEMO's work to achieve greater transparency about the transmission loss factor framework.

However, the Commission did not support changes to mandate a more frequent publication and use of MLFs at this time. It acknowledged the desire to address a perceived downside of the current methodology in the use of static values for a year. However, a greater number of loss factor values would be likely to result in additional uncertainties in times of MLF variability and potentially reduced notice to market participants of changes to MLF values.

For these reasons, the Commission concluded in the draft rule determination that a move towards dynamic loss factors would be best assessed in detail through its COGATI review. Under this review, the Commission and stakeholders would be able to take a holistic view on the potential for wider market reforms to include the use of dynamic loss factors.

### 7.1.3 Public hearing

At the pre-final determination hearing, Infigen acknowledged the recent work carried out by AEMO to publish more regular updates of MLF values and commented that this was a positive step in addressing transparency for market participants.[270] No other comments were made by the presenters on this issue.

268 EPSDD submission to the consultation paper, p. 6.

269 The final rule on the transparency of new projects was made on 24 October 2019. AEMC, *National Electricity Amendment (Transparency of new projects) Rule 2019, No. 8.*

270 Infigen, transcript of pre-final rule determination hearing, p. 17.

### 7.1.4 Stakeholder views on the draft rule determination

Infigen followed its comments at the hearing with a submission noting that:[271]

> addressing the lack of transparency and guiding information available to market participants, including the potential swings of MLFs and their sensitivity to new generation in the neighbouring areas or beyond, is the appropriate response at this time.

EnergyAustralia suggested that standard deviation and intra-day information such as scatter plots and/or time series view for varying loss factors should also be published by AEMO to support decision-making by participants.[272]

### 7.1.5 Final rule determination assessment

The Commission supports AEMO's commencement of reporting MLF values for information and transparency purposes. It notes the suggestions made that some additional information on the sensitivity of MLF values could also be valued by market participants. On this, AEMO has indicated openness to engaging further with stakeholders.[273] The Commission considers this is the appropriate approach to explore the publication of additional MLF information that will aid market participants. It does not consider that any amendments to the NER are necessary for these developments to occur.

### 7.1.6 Final rule determination

The Commission supports AEMO's publication of MLF data on a quarterly basis to the market for information and transparency purposes.  It welcomes the timeliness of commencing the new reporting arrangements and encourages stakeholders to engage further with AEMO in future information publication developments. Combined with the recent changes to the NER in regard to information on new investments, the Commission anticipates that market participants will be able to make better informed investment and operational decisions which will better contribute to the achieving of the NEO.

## 7.2 Amount of notice given to market participants

Under the current arrangements AEMO is required to publish the MLF values each 1 April to apply for 12 months from 1 July. This provides market participants three months' notice of any changes to the intra-regional loss factor values and the inter-regional loss factor equations. In the consultation paper the Commission requested stakeholders consider if the NER should be amended to shorten or lengthen the notice period, taking into account:[274]

- the benefits for market participants and investors of increased notice of changes in loss factors

271 Infigen submission to the draft determination, p. 2.

272 EnergyAustralia submission to the draft determination, pp. 1-2.

273 AEMO submission to the draft determination, p. 2.

274 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 18.

- the ability for transmission loss factors to reflect recent changes in generator behaviour and new generating units.

### 7.2.1 Stakeholder views on the request

No stakeholders suggested that there is a need to change the amount of notice given by AEMO to market participants regarding the MLF values.

In particular, ERM Power submitted that it does not see any material benefit to altering the current publication timetable of transmission loss factors to apply from 1 July each year from the immediately preceding 1 April. It considered the three-month notification period allows final contracting level adjustments to be negotiated and concluded prior to the commencement of the financial year.[275]

Similarly, MEA Group submitted three months' notice consistent with quarterly publishing. Mondo and the CEIG submitted that there is no reason to change this.[276]

### 7.2.2 Draft rule determination

The Commission noted the submissions it received on the amount of notice AEMO has to give to market participants and concluded that the current three months' notice is appropriate. As a result, the draft rule did not change to the amount of notice provided by AEMO to market participants for the new MLF values.

### 7.2.3 Public hearing

The issue of the period of notice provided by AEMO to market participants for new MLF values was not discussed by presenters at the pre-final determination hearing.

### 7.2.4 Stakeholder views on the draft rule determination

No submissions made in response to the draft rule determination commented on this issue.

### 7.2.5 Final rule determination assessment

No additional information on this issue has been provided to the Commission following publication of the draft rule determination. The Commission considers that its assessment in the draft rule determination remains appropriate.

### 7.2.6 Final rule determination

As stated above and in the draft rule determination, the Commission considers that the current three months' notice by AEMO is appropriate. The notice period meets the needs of generators, as well as AEMO, to make informed operational decisions consistent with the long term interest of consumers. As a result, the final rule does not change to the amount of notice provided by AEMO to market participants for new MLF values.

275 ERM Power submission to the consultation paper, p. 4.

276 Submissions to the consultation paper: MEA Group, p. 3; Mondo, p. 10; CEIG, p. 16.

## 7.3 Using a forward or backward-looking methodology

AEMO currently uses a forward-looking methodology to calculate MLFs based on forecasts of load and generation data consistent with the principles set out in clause 3.6.2A(d) of the NER. This clause states that in preparing the methodology for forecasting and modelling load and generation data, AEMO must implement a number of principles. Relevantly, that the forecast load and generation data must be representative of expected load and generation in the financial year in which the MLFs are to apply, having regard to:

- actual data from the previous 12-month period defined by the methodology
- projected load growth between each calendar month of that 12-month period of the actual data and the financial year for which the MLFs apply
- projected network configuration and performance for the financial year for which the MLFs apply.

As noted in the consultation paper, MLF values were initially calculated using a backward-looking method. The change to a forward-looking basis for the calculations was made in 2003 to reduce the two-year delay between changes in generation and the impact on the loss factor values inherent in the backward-looking method.

Given that both forward and backward-looking methodologies are feasible, stakeholders were requested to consider if a forward or backward-looking methodology should be used for loss factor calculations in the future.[277]

### 7.3.1 Stakeholder views on the request

Submissions to the consultation paper indicated that stakeholders supported the continued use of the forward-looking methodology to calculate loss factors.

MEA Group submitted that it supported the forward-looking methodology which, in its opinion, allows generators to manage their revenue risk year-on-year.[278]

ERM Power also supported the ongoing use of the forward-looking loss factor calculation methodology. It considered that this approach ensures that forecast changes to account for commissioning of new generation sources or significant load can be included as well as forecast major generator planned outages as indicated in the Medium Term Projected Assessment of System Adequacy (MT PASA).[279]

The CEIG, MEU and EPSDD all expressed support for the use of the forward-looking methodology.[280]

277 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, pp. 18-19.

278 MEA Group submission to the consultation paper, p. 3.

279 ERM Power submission to the consultation paper, p. 5.

280 Submissions to the consultation paper: CEIG, p. 16; MEU, p. 3; EPSDD, p. 6.

### 7.3.2 Draft rule determination

In its draft rule determination, the Commission noted that all the submissions it received on the use of the forward-looking methodology to calculate loss factors indicate that this is the preferred approach and no change was sought by market participants.

The Commission also commented that changing to a backward-looking approach would be likely to result in less accurate forecasts and result in dampened locational and investment signals.  In particular, a backward-looking approach would not include expected new investment in the modelling and calculations. This is particularly relevant in current market conditions, where rapid growth in new generation connection are having a significant impact on MLF values.  As a result, using a backward-looking approach would be likely to increase uncertainty for market participants. For these reasons, the Commission concluded that MLFs should continue to be calculated based on the current forward-looking methodology.

The Commission considered that no change away from the forward-looking methodology to calculate loss factors was necessary and no amendment to this effect are included in the draft rule.

### 7.3.3 Public hearing

The issue of whether to use a forward or backward-looking approach to calculating MLF values was not discussed by presenters at the pre-final determination hearing.

### 7.3.4 Stakeholder views on the draft rule determination

No submissions made in response to the draft rule determination commented on this issue.

### 7.3.5 Final rule determination assessment

No additional information on this issue has been provided to the Commission following publication of the draft rule determination. The Commission considers that its assessment in the draft rule determination remains appropriate.

### 7.3.6 Final rule determination

As stated above and in the draft rule determination, the Commission has concluded that the current use of a forward-looking approach to calculate MLF values is appropriate. The final rule does not amend this aspect of the MLF methodology.

## 7.4 Changing virtual nodes

This section discusses stakeholder suggestions that the loss factor framework should be amended with respect to the use of virtual nodes in general, and more specifically in regard to Berri in South Australia.

### 7.4.1 Stakeholder views on the request

In its submission to the consultation paper, the ACT Government EPSDD suggested that AEMO could start its determination of loss factors by calculating marginal loss factors for all generators using the current methodology and then define several virtual nodes for each state.[281] Then, according to EPSDD, AEMO could calculate the actual losses forecast to occur at each virtual node. This would then allow AEMO to calculate the forecast IRSR for each virtual node. With this information, AEMO would then be able to scale the loss factor for each generator within a virtual node such that the forecast IRSR for the virtual node would equal zero.[282]

In EPSDD's view, AEMO would be able to determine the size and location of the virtual nodes by balancing accuracy (which would be supported by smaller virtual nodes) and simplicity (which would arise from larger but few virtual nodes). It acknowledged that its suggested approach would not produce "exactly the correct answer". However, it did consider that its virtual node approach would be more accurate than the current method to calculating loss factors without being as complex.[283]

A different suggestion in relation to virtual nodes was made by CIT, an end use customer located near Berri in South Australia.[284]

CIT sought to resolve its particular concern regarding the recent changes it has experienced in relation to transmission loss values. It considered that the change and difference between Berri and Red Cliffs, 150 km apart, "defies both logic and explanation"[285]

CIT linked the changes in transmission loss factor values to the changing flow of power across the Murraylink interconnector rather than to changing load or generation in the area. There are a number of compounding features CIT submitted as possibly contributing to the increased loss values it is experiencing:[286]

- Losses are only apportioned to a few nodes close to the interconnector terminal.
- The use of a virtual transmission node (VTN) for South Australian small customers means that the losses are not individually attributable to small business customers supplied through the Berri node, but losses are attributed to large business customers at their connection point.
- The IRSR collection is on a regional loss basis but returned through TUOS reductions and applied on a postage stamp basis.

CIT identified four possible solutions to address its concerns. Of these four options, CIT indicated its preference for the AEMC to consider implementing either:[287]

- declaring Berri as a virtual node

281 A virtual node is a non-physical node used for the purpose of market settlements, having a transmission loss factor determined in accordance with clause 3.6.2(b)(3) of the NER.

282 EPSDD submission to the consultation paper, p. 5.

283 EPSDD submission to the consultation paper, pp. 5-6.

284 CIT pumps water from the Murray River to 1,600 growers across different irrigation districts in South Australia. Water is supplied through fully automated pumping stations and pressurised pipeline systems.

285 CIT (1 of 3) submission to the consultation paper, p. 1; Note that the Berri node terminus for Murraylink, the high voltage connection between Berri, South Australia and Red Cliffs, Victoria. The Berri loss factors for 2016-17 and 2019-20 were 0.9379 and 1.1277 respectively.

286 CIT submission to the consultation paper, p. 2.

287 CIT submission to the consultation paper, p. 2.

- establishing another node which is the terminus node and then apportioning the losses across the state.

Other stakeholders expressed support in addressing the problem experienced by CIT.[288] EUAA specifically supported the establishment of another node with the terminus node and then apportioning losses across South Australia.[289] The SA Government submitted that the AEMC should consider mechanisms that could smooth the impacts of MLFs for connection points like the CIT's at Berri.[290]

### 7.4.2 Draft rule determination

Following consideration of stakeholder concerns in relation to virtual transmission nodes, the Commission concluded that the draft rule did not need to amend the NER to address the issues raised.

The draft rule determination noted EPSDD's suggestion to create a number of virtual nodes within a jurisdiction and determine generator loss factors such that the IRSR relevant to that virtual node balances to zero. This approach represented a significant change in the application of marginal loss factors to generation assets in the NEM. It also suggested that the IRSR represents an undesirable calculation error in marginal loss factors that should be corrected.

However, the Commission expressed concern that the use of virtual nodes as suggested would move the transmission loss factor framework further away from dynamic regional pricing and dynamic loss factors and create more uncertainty in times of high MLF volatility.

In addition, the suggested approach did not recognise that IRSR arises from the wholesale market settlement process and reflects the use of MLFs to adjust prices between the RRN and the transmission connection point of a customer.[291] The settlements process generally tends to recover more from customers than is needed to pay generators because charging customers marginal costs generally exceeds average costs. The remainder after paying generators is returned to customers through a decrease in TUOS charges.[292] That is, the IRSR is not designed to equal zero, it is a feature of using marginal pricing principles across the NEM. However, the end result is that customers will have paid generators for the electricity they have received.

As a result of these concerns, the Commission did not assess the EPSDD's suggested changes to the transmission loss framework any further in the draft rule determination. It also noted that the changes would be unlikely to contribute to the achievement of the NEO.

The draft rule determination also addressed the concerns raised by CIT. The Commission noted that CIT's concerns have been acknowledged by AEMO:[293]

288 Submissions to the consultation paper: MEU, p.2; South Australian Department for Energy and Mining, p. 2; EUAA, p. 3.
289 EUAA submission to the consultation paper, p. 3.
290 South Australian Department for Energy and Mining submission to the consultation paper, p. 2.
291 Metering inaccuracies are also captured in the IRSR.
292 The IRSR can be negative. In this case, customers will incur an increase in TUOS charges to enable generators to be correctly paid for the electricity generated.
293 CIT submission to the consultation paper, attachment 2 (letter from AEMO to CIT), p. 1.

> You are correct that MLF volatility has significantly increased since the Murray Link has been commissioned in 2002. This volatility is an unfortunate side-effect of the way the MLF's are calculated in accordance with the national electricity rules.

The Commission acknowledged CIT's particular situation: Murraylink is the only interconnector associated with a very weak connection point. As a result, the variation of the Murraylink flow creates significant volatility for the Berri MLF. As previously noted, a key purpose of MLFs is to provide a locational signal to prospective investors. However, the influence of the Murraylink interconnector on MLF values for surrounding nodes like at Berri, may result in limited usefulness of these particular MLFs for long term investment signals.

#### Comparison between the Red Cliffs and Berri MLFs

CIT noted the difference in the MLF values calculated for Berri and Red Cliffs. It regarded the difference as inexplicable given the distance between the locations. However, such a comparison is likely to be misleading as the MLFs for the two locations are not calculated on the same basis. Specifically, the MLF for Berri is defined with respect to the price at Torrens Island (in Adelaide), while the MLF for Red Cliffs is defined with respect to the price at Thomastown (in Melbourne). As a result, the MLFs for the two locations would be expected to be different.

Also, with all other things held constant, an increase of the Murraylink flow from South Australia to Victoria will increase the MLF for Berri (that is, a larger value) but reduce the MLF for Red Cliffs (that is, a lower value). Over the last few years, AEMO data on flows experienced on the Murraylink indicate that the flow has been from Berri to Red Cliffs more of the time compared to the past.

#### Declaring Berri as a virtual node

CIT suggested that forming a VTN at Berri would provide it with relief from high and variable MLF values. The Commission considered this in the draft rule determination and concluded that declaring a VTN for Berri would not provide any practical relief for the larger CIT loads at Berri. This was because the intra-regional loss factor (IRLF) for a VTN is a weighted average of the IRLF for the nodes that make up the VTN. As such, the IRLF for a Berri VTN would simply be the IRLF for Berri transmission connection points. That is, there would not be any difference in the MLFs applied to CIT's larger loads.

In addition, the Commission noted that the detail of specifying a VTN at Berri is not a matter for this rule change process. This process (and any more preferable Rule made by the Commission) is determined by the scope of the issues raised in the rule change requests, which did not refer to virtual nodes. Nevertheless, the draft rule determination noted that clause 3.6.2(b)(3) of the NER provides for assigning connection points to a VTN with the agreement of the AER.

**Establishing a terminal node and apportioning losses across the state**

CIT suggested that a node at the terminus of Murraylink could be established and the losses attributable to that location be shared across the whole state rather than the few nodes surrounding Berri (which is the current situation).

Currently, there is a node at the South Australian terminus of Murraylink. In the draft rule determination, the Commission stated that adding another did not appear to provide a benefit. In addition, the Commission noted that establishing a new node would be a matter for the relevant TNSP and AEMO with the agreement of the AER under clause 3.6.2(b)(3) of the NER. It also noted that clause 3.6.3(f)(2) of the NER allows the assignment of connection points on a distribution network to a transmission network connection point or VTN subject to the approval of the AER and informing AEMO. Other methods to establish a new terminal node are not a matter for this rule change process as the issues raised by CIT were not raised in the rule change requests lodged by Adani Renewables.

### 7.4.3 Public hearing

Issues relating to virtual transmission nodes were not discussed by presenters at the pre-final determination hearing.

### 7.4.4 Stakeholder views on the draft rule determination

The South Australian Department for Energy and Mining noted the Commission's intention to engage further with AEMO on the issue raised by CIT.[294]

### 7.4.5 Final rule determination assessment

As noted in the draft rule determination, the suggestion made by the EPSDD raises concerns for the Commission in that it represents a significant move away from the current underlying marginal approach embedded in the operation of the NEM. No further information on this issue has been provided to the Commission and it is satisfied that its assessment in the draft rule determination remains relevant.

Following the publication of the draft rule determination, the Commission has engaged with interested stakeholders in relation to CIT's concerns. As a result, the AER has undertaken to publish a guideline setting out a process for relevant parties to follow to seek assignment of a node to a transmission connection point or a VTN (as provided under clause 3.6.3(f)(2) of the NER). The AER guideline will also inform parties of the matters it will have regard to in making such a decision. The Commission welcomes this development and anticipates that an AER guideline will assist in the resolution of CIT's particular circumstances as well as improve stakeholders' understanding the application of VTNs generally.

### 7.4.6 Final rule determination

Consistent with the draft rule determination, the Commission has concluded that amendments to the NER in relation to EPSDD or CIT's concerns regarding VTNs are not

294 South Australian Department for Energy and Mining submission to the draft determination, p. 1.

required. The Commission anticipates that CIT will be able to resolve its particular issues with the assistance of the AER.

## 7.5 Other changes to AEMO's calculations

Stakeholders submitted a number of suggested changes to the consultation paper that, in their view, could be readily made to improve the transmission loss factor framework. These are discussed in turn below and include:

- AEMO's own review of the loss factor methodology
- AEMO's discretion to amend MLFs for revised outlook of generator availability
- AEMO sharing its model with selected consultants.

### 7.5.1 Stakeholder views on the request

#### AEMO's review of the loss factor methodology

In its submission to the consultation paper, AEMO stated that it will conduct a formal stakeholder consultation process on the methodology for determining MLFs to confirm that it remains fit-for-purpose. It also stated that it is updating the tools and processes used to calculate MLFs to "better handle the increased calculation complexity associated with changing power system conditions."[295]

Origin noted and supported AEMO's review of its methodology for forecasting MLFs.[296]

#### Revising MLFs

ENA suggested changes to the MLF framework to address the uncertainties arising out of the current volatility in MLFs. It submitted that the AEMC should make a more preferable rule which provides AEMO with discretion to amend MLFs to cater for a revised outlook of generator availability, republish the MLF values and provide a short notification period before the new MLF values take effect where the impacts are expected to be material.[297]

#### Sharing of AEMO's model

In relation to concerns expressed about the accessibility of the MLF calculations to market participants, AEMO suggested that it could potentially share its model with a selected group of consultants.[298] The resulting model information could enable developers and investors in generation assets to obtain better MLF estimates as part of their due diligence processes.

Canadian Solar supported the sharing of AEMO’s actual model parameters with a limited number of "super consultants" because it expected that this change would further minimise investor uncertainty and deliver lower cost renewable development.[299]

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295 AEMO submission to the consultation paper, pp. 1 & 4.

296 Origin submission to the consultation paper, p. 1.

297 ENA submission to the consultation paper, p. 2.

298 AEMC, Transmission loss factor rule change workshop, Brisbane, 4 July 2019.

299 Canadian Solar submission to the consultation paper, p. 2.

Similarly, CEC supported AEMO's suggestion that it share its MLF model with "accredited" consultants.[300]

### 7.5.2 Draft rule determination

The Commission reviewed the various suggested changes to the MLF framework in its draft rule determination.

#### AEMO's review of the loss factor methodology

The draft rule determination noted that AEMO's review of the loss factor methodology would provide an additional avenue for stakeholders to engage and discuss with AEMO what other improvements to the current methodology can be made within the existing rules. The Commission expressed support for AEMO in this work and made a draft rule to provide AEMO with greater flexibility in conducting consultation on the loss factor methodology.

#### Revising MLFs

ENA suggested that AEMO be able to adjust MLF values for revised forecasts. The Commission acknowledged that permitting such revisions would improve the accuracy of the forecast MLF values. However, it expected that this arrangement would be complicated to implement and could result in additional variability and risk for market participants. This is because it would be uncertain to generators and investors as to if and when AEMO will change loss factors within the period between 1 April (when MLF values are initially published) and 1 July (when the MLFs take effect). The Commission also noted such arrangements would necessarily result in a very short notification period of the updated loss factor values for the market.

On balance, the Commission considered that under the current framework, permitting AEMO to make late adjustments to loss factor values would be unlikely to be beneficial for investors and owners of generation assets. The suggested changes were not incorporated in the draft rule.

#### Sharing of AEMO's model

AEMO had suggested that it could share its model with a selection of consultants to improve transparency in the market and improve investment decision-making.

The Commission acknowledged the potential of this suggestion and noted that it was in its early stages. It also noted in the draft rule determination that in considering whether to implement a framework that enables loss factor modelling to be shared, it is important that the level of competition in the market for consultants having access to the AEMO model is considered when the selection of the accredited consultants is made.

In particular, if the issue of providing the model only to a few selected consultants is because of the confidentiality of the information contained in the model, then AEMO should consider other ways of managing confidentiality concerns to enable a larger group of consultants to

300 CEC submission to the consultation paper, p. 2.

have access to the model. The Commission considered that a larger group of approved consultants would be likely to have greater benefit to market participants than only approving a few consultants.

While the draft rule provided changes to the loss factor methodology provisions of the NER that would support AEMO's anticipated review of the methodology in the near future, it did not include any amendments with respect to sharing the AEMO model.

### 7.5.3 Public hearing

The issues set out in the draft rule determination, as described above, were not specifically discussed by presenters at the pre-final determination hearing.

However, related to the issue of sharing AEMO's model with consultants, Infigen suggested that a "fee for service" arrangement could be provided by AEMO to participants who seek additional information, such as sensitivities of loss factor values, derived from its modelling. In its view, such additional information could assist participants in making decisions by clarifying the impact of a potential change in an MLF value.[301]

### 7.5.4 Stakeholder views on the draft rule determination

No submissions included comments on the particular issues of AEMO amending MLFs for changes in generator availability, or sharing its modelling used to calculate loss factors.

AEMO's submission to the draft rule determination reiterated its earlier submission that it intended to carry out a review of the MLF methodology. It stated that it expected to commence the required consultation process following the April 2020 publication of the 2020-2021 MLF values. This process would have regard to changes made to the NER as a result of this rule change process.[302]

Related to the sharing of AEMO modelling, Infigen reiterated its suggestion made at the pre-final determination hearing that AEMO could provide an additional service to allow participants to request particular additional MLF related information arising from its modelling.[303]

### 7.5.5 Final rule determination assessment

No additional information has been provided to the Commission in relation to AEMO's planned review of the MLF methodology or the suggestion that AEMO be able to make late adjustments to MLF values in light of revisions to generator outlooks. Accordingly, the Commission considers that its discussion in the draft rule determination, and as noted above, remains relevant.

In relation to AEMO sharing its model with selected parties, or providing certain services to participants on a fee paying basis, the Commission notes that neither of these activities require an amendment to the NER. Nevertheless, as set out in the draft rule determination, a

301 Infigen, transcript of the pre-final determination hearing, p. 17.

302 AEMO submission to the draft determination, p. 2.

303 Infigen submission to the draft determination, p. 3.

number of considerations are relevant for AEMO when deciding on whether to action either of these suggestions.

### 7.5.6 Final rule determination

Consistent with the draft rule, the Commission has made a final rule that supports AEMO's forthcoming consultation process to review the transmission loss factor methodology (as described in Chapter 6 of this final rule determination). The final rule does not include any amendments to the NER that relate to the issues of AEMO making late adjustments to MLF values in light of revisions to generator outlooks, sharing its model with selected parties, or providing certain services to participants on a fee paying basis.

# ABBREVIATIONS

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ALF | average loss factor(s) |
| COGATI | Coordination of generation and transmission investment implementation review |
| Commission | see AEMC |
| ESB | Energy Security Board |
| IRSR | intra-regional settlement residue |
| MCE | Ministerial Council on Energy |
| MLF | marginal loss factor(s) |
| MNSP | market network service provider |
| NEL | National Electricity Law |
| NEM | national electricity market |
| NEO | national electricity objective |
| NER | National Electricity Rules |
| RRN | regional reference node |
| TNSP | transmission network service provider |
| TUOS | transmission use of system |
| VTN | virtual transmission node |

# A LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

## A.1 Final rule determination

In accordance with ss. 102 and 103 of the NEL the Commission has made this final rule determination in relation to the rule changes proposed by Adani Renewables.

The Commission's final determination is:

- to not make a final rule under the NEL in the form proposed by Adani Renewables
- to make a more preferable rule under the NEL, substantially in the form as suggested by AEMO during this rule change process.

The Commission's reasons for making this final rule determination are summarised in section 2.5 and set out in detail throughout this determination.

A copy of the more preferable rule is attached to and published with this final rule determination. Its key features are described in section 2.4.

## A.2 Power to make the rule

The Commission is satisfied that the more preferable rule falls within the subject matter about which the Commission may make rules. The more preferable rule falls within s. 34 of the NEL as the framework in which intra-regional loss factors are calculated relates to the operation of the national electricity market and the activities of persons (including registered participants) participating in the NEM or involved in the operation of the national electricity system. Further, the more preferable rule falls within the matters set out in Schedule 1, item 34(a) of the NEL as it relates to settlement of transactions for electricity or services purchased or supplied through the wholesale exchange operated and administered by AEMO.

## A.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the final rules
- the rule change requests
- submissions and other information received during the first round of consultation
- information gathered from the stakeholder workshop held on 4 July 2019
- information presented to the Commission at the pre-final determination hearing held on 4 December 2019
- submissions and other information received during the second round of consultation
- its quantitative and qualitative analysis as to the ways in which the proposal will, or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[304]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the rule is compatible with the proper performance of AEMO's declared network functions.[305] The more preferable rule is compatible with AEMO's declared network functions because it is unrelated to them and therefore does not affect the performance of those functions.

## A.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

The final rule does not amend any clauses that are currently classified as civil penalty provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the final rule be classified as civil penalty provisions.

## A.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The final rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the final rule be classified as conduct provisions.

304 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

305 Section 91(8) of the NEL.

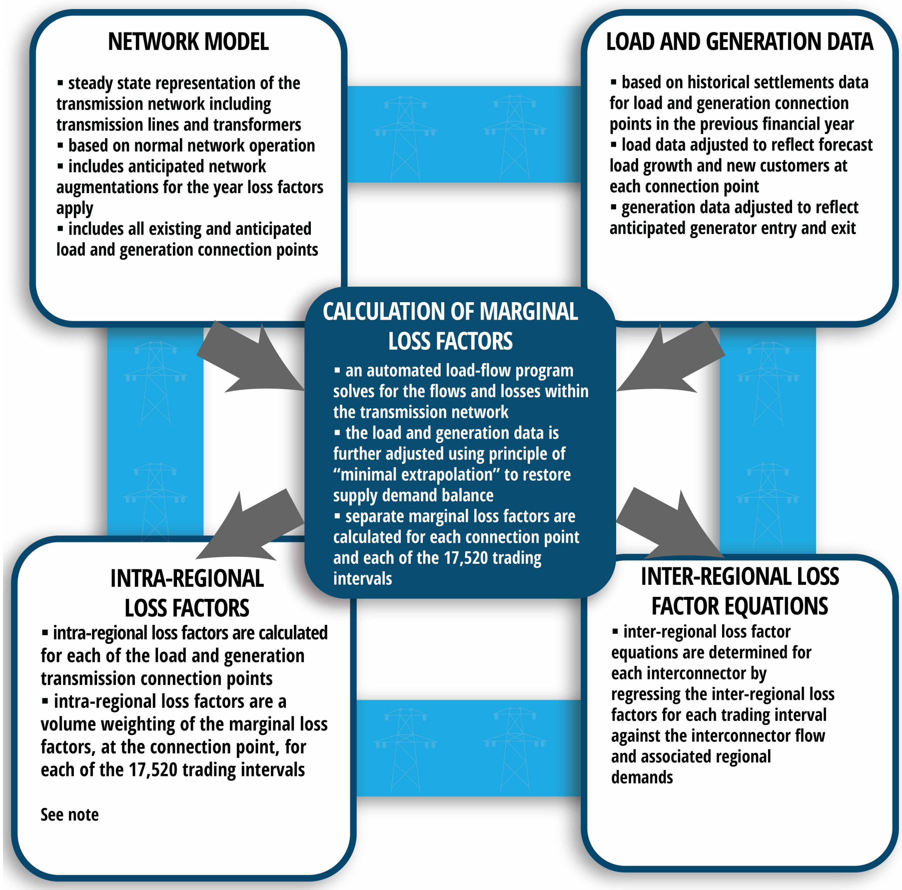
# B CURRENT LOSS FACTORS FRAMEWORK

## B.1 Current NER arrangements

The requirements in relation to the calculation of inter-regional and intra-regional loss factors for the NEM transmission networks are found in clauses 3.6.1, 3.6.2 and 3.6.2A of the National Electricity Rules (NER). In addition to these provisions, AEMO also publishes its calculation methodology.[306]

Figure A.1 below illustrates the process for calculating the intra-regional and inter-regional loss factors.

**Figure B.1: Loss factor calculation process**




Source: AEMC

Note: The intra-regional loss factors are also often referred to as marginal loss factors (MLFs), transmission loss factors or static/single loss factors.

306 This can be found on AEMOs website: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries

### B.1.1 Intra-regional loss factors

Intra-regional loss factors notionally describe the marginal electrical energy losses for electricity transmitted between a regional reference node (RRN) and a transmission connection point in the same region for a defined time period and associated set of operating conditions.[307] Intra-regional loss factors are also commonly referred to as marginal loss factors (MLFs), transmission loss factors and static loss factors.[308]

AEMO must determine, publish and maintain, in accordance with the Rules consultation procedures, a methodology for the determination of intra-regional loss factors to apply for a financial year for each transmission network connection point.[309] AEMO must publish the intra-regional loss factors it determines by 1 April prior to the financial year in which they are to apply.[310]

When preparing this methodology, AEMO must implement a set of principles that can be summarised as follows:[311]

- the intra-regional loss factors are to apply for a financial year
- an intra-regional loss factor must, as closely as is reasonably practicable, describe the average of the marginal electrical energy losses for electricity transmitted between a transmission network connection point and the RRN in the same region for each trading interval of the financial year in which the intra-regional loss factor applies
- the intra-regional loss factors must aim to minimise the impact on the central dispatch process of generation and scheduled load compared to that which would result from a fully optimised dispatch process taking into account the effect of losses
- the intra-regional loss factors are determined using forecast load and generation data, as described in clause 3.6.2A
- the intra-regional loss factor for a transmission network connection point is determined using a volume weighted average of the marginal loss factors for the transmission network connection point for the financial year in which the intra-regional loss factor applies
- in determining an intra-regional loss factor for a transmission network connection point, flows in network elements that solely or principally provide market network services will be treated as invariant.[312]

Generally a single intra-regional loss factor applies for each transmission connection point for a financial year. However, two intra-regional loss factors can be applied when AEMO determines, in accordance with its loss factor methodology, that one intra-regional loss factor does not, as closely as is reasonably practicable, describe the average of the marginal

307 Clause 3.6.2(b)(1) of the NER.

308 Intra-regional loss factors are commonly called marginal loss factors because the marginal impact on losses is considered when determining the value, transmission loss factors because they apply to transmission connection points and static loss factors because a single static values applies for a whole financial year.

309 Clause 3.6.2(d) of the NER.

310 Clause 3.6.2(f1) of the NER.

311 Clause 3.6.2(e) of the NER.

312 The losses within market network services are treated separately.

electrical energy losses for electricity transmitted between a transmission network connection point and the RRN.[313] Two intra-regional loss factors may be required for storage facilities (e.g. pump storage or batteries) when the energy at the transmission connection point is both positive (generating) and negative (load) to prevent the volume weighting process from determining a meaningless single static intra-regional loss factor.[314]

Intra-regional loss factors may, with the agreement of the AER, be averaged over an adjacent group of transmission network connection points within a single region to define a virtual transmission node (VTN) with an intra-regional loss factor calculated as the volume weighted average of the intra-regional loss factors of the constituent transmission network connection points.[315] VTNs are currently defined in New South Wales, South Australia and Tasmania.[316]

Intra-regional loss factors are used as price multipliers that can be applied to the regional reference price to determine the local spot price at each transmission network connection point and VTN.[317]

In addition, AEMO determines intra-regional loss factors for new and modified connection points in the financial year in which an intra-regional loss factor is to apply if it did not determine an intra-regional loss factor in the preceding financial year.[318] AEMO must, as far as practicable, follow its methodology when determining these intra-regional loss factors.[319]

### B.1.2 Inter-regional loss factors

Under clause 3.6.1 of the NER, inter-regional loss factors describe the marginal electrical energy losses for electricity transmitted through regulated interconnectors from a regional reference node (RRN) in one region to the RRN in an adjacent region.[320]

AEMO must determine, publish and maintain a methodology for the determination of inter-regional loss factor equations for a financial year,[321] in accordance with the rules' consultation procedures.[322]

When preparing this methodology for inter-regional loss factor equations, AEMO must implement the principles set out in clause 3.6.1(d) of the NER, including that the inter-regional loss factors:

313 Clause 3.6.2(b)(2)(i) of the NER.

314 A volume weighted loss factor can become meaningless when the total energy at a connection point is close to zero; that is, the sum of the generation is approximately equal to the sum of load over the financial year. When this occurs both the numerator and the denominator in the calculation approach zero and the ratio becomes poorly defined. This is discussed further in section 5.6.1 of version 7 of AEMO's "Forward-looking transmission loss factors" methodology, which can be found here: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2017/forward-looking-loss-factor-methodology-v70.pdf?la=en&hash=C475D2D9DEAAA538A885FD3664B26A64.

315 Clause 3.6.2(b)(3) of the NER.

316 Regions List and Draft Marginal Loss Factors: FY 2019-20, published by AEMO on 1 April 2019.

317 Clause 3.6.2(c) of the NER.

318 Clause 3.6.2(i) of the NER.

319 Clause 3.6.2(j) of the NER.

320 Clause 3.6.1(b)(1) of the NER.

321 Clause 3.6.1(c) of the NER.

322 The rules' consultation procedures are defined in rule 8.9 of the NER.

- apply for a financial year and must be suitable for use in central dispatch for the NEM
- are calculated by inter-regional loss factor equations that "as closely as is reasonably practicable" describe the marginal electrical energy losses for electricity transmitted through a regulated interconnector between the two relevant RRNs and aim to minimise the impact on the central dispatch process of generation and scheduled load
- are calculated by using forecast load and generation data for the relevant financial year by applying regression analysis.

In addition, AEMO must publish the inter-regional loss factor equations it determines by 1 April prior to the financial year in which they are to apply.[323]

### B.1.3 Load and generation data used to determine inter-regional loss factor equations and intra-regional loss factors

Clause 3.6.2A of the NER obligates AEMO, in accordance with the rule consultation procedures, to determine, publish and maintain a methodology for determining the load and generation data to be used to determine the inter-regional loss factor equations and intra-regional loss factors for each financial year. This methodology includes:[324]

- forecasting the load and generation data to be used to determine the inter-regional loss factor equations and the intra-regional loss factors. This includes new or revised intra-regional loss factors for connection points that are established or modified during the financial year in which the intra-regional loss factors are to apply
- modelling any additional load and generation data, where required, to be used in determining inter-regional loss factor equations
- the collection of relevant data from registered participants, including without limitation deadlines for the provision of that data.

In preparing the methodology for forecasting and modelling load and generation data, AEMO must implement a number of principles, which are summarised as follows:[325]

- the forecast load and generation data must be representative of expected load and generation in the financial year in which the inter-regional loss factor equations or intra-regional loss factors are to apply, having regard to;
    - actual load and generation data from the previous 12-month period defined by the methodology
    - projected load growth between each calendar month of the actual load and generation data and the same calendar month in the financial year for which the inter-regional loss factor equations and intra-regional loss factors apply
    - the projected network configuration and projected network performance for the financial year in which the inter-regional loss factor equations and intra-regional loss factors apply.

323 Clause 3.6.1(f) of the NER.
324 Clause 3.6.2A(b) of the NER.
325 Clause 3.6.2A(d) of the NER.

- additional modelled load and generation data sets must only be used in the determination of inter-regional loss factor equations where the range of forecast load and generation data is not sufficient to derive inter-regional loss factor equations to apply over the full range of transfer capability of the regulated interconnector.

In addition, registered participants are required to provide the information set out in the methodology developed and published by AEMO. This information includes the deadlines for the provision of that information and any other obligations with respect to the provision of that information set out in AEMO's published methodology.[326]

### B.1.4 Application of the intra-regional loss factors

The intra-regional loss factors determined by AEMO are applied in the both their central dispatch and settlement process. This occurs in the following ways:

- semi-scheduled and scheduled generators' dispatch offers are divided by the intra-regional loss factor (to refer the offer to the RRN to which that connection point is assigned)[327]
- scheduled loads' dispatch bids are divided by the intra-regional loss factor (to refer the offer to the RRN to which that connection point is assigned)[328]
- the local spot price at each transmission network connection point is the spot price at the RRN to which the connection point is assigned multiplied by the relevant intra-regional loss factor applicable to that connection point.[329]
- being used in the calculation of compensation in relation to AEMO directions[330]
- when determining the settlements payments (paid by market customers and paid to generators) by multiplying the measured energy (that is, the adjusted gross energy) in the trading interval, the regional reference price and the relevant intra-regional loss factor.[331]

## B.2 AEMO's role in determining intra-regional loss factors

As discussed earlier, the NER provides a number of key principles that AEMO must follow when it determines the inter-regional loss factor equations and the intra-regional loss factors each financial year. In addition, AEMO is required to develop and publish its methodology for determining the loss factors. This methodology is available on the AEMO website.[332]

AEMO uses an automated load flow program to calculate the loss factors for the financial year on which the inter-regional and intra-regional loss factors apply.[333] This program requires

326 Clause 3.6.2A(e) of the NER.
327 Clause 3.8.6(h)(3) of the NER.
328 Clause 3.8.7(f) of the NER.
329 Clause 3.9.1(c) of the NER.
330 Clause 3.12.2(a)(2) of the NER.
331 Clause 3.15.6(a) of the NER.
332 http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2017/Forward-Looking-Loss-Factor-Methodology-v70.pdf
333 AEMO uses the TPRICE program for calculating the NEM loss factors.

a network model that represents the region's transmission network plus the connection energy flows for each trading interval for the generators and loads connected to the transmission network.

The following discussion summarises AEMO's forward-looking intra-regional loss factor methodology and its application and includes:

- network model
- load forecast data
- controllable network element flow data
- generation data
- restoring the supply and demand balance
- intra-regional loss factors
- inter-regional loss factor equations
- publication of the loss factors.

### B.2.1 Network model

The inter-regional and intra-regional loss factors are determined from the losses that occur for energy flows within the region's transmission network. Therefore, an important input when determining the loss factors is a suitable model of the NEM transmission network.[334]

The network model AEMO uses is a single network representation to represent the normal network configuration that is anticipated for the financial year in which the inter-regional and intra-regional loss factors will apply. This model is based on the existing network plus any network augmentations that are expected to be commissioned during that year. Information on expected network augmentations are those which have been determined in consultation with the transmission network service providers (TNSPs) who supply relevant network data regarding these augmentations.

In addition, AEMO must ensure that the network model includes all existing connection points and those that are anticipated to be established before the end of the financial year which the inter-regional and intra-regional loss factors will apply.

### B.2.2 Load forecast data

The automated load flow program used to calculate the inter-regional and intra-regional loss factors requires estimates of the energy consumed at each load connection point for each trading interval. This load energy information is provided to AEMO by TNSPs. AEMO performs due diligence on the provided data to ensure the forecasts are consistent with the most recent load forecasts used in its electricity statement of opportunity (ESOO) document.

The connection point load forecasts provided by the TNSPs:

334 AEMO bases the network model on the PSSE load flow models it uses for contingency analysis and for the initial conditions for the more detailed stability studies it performs to assess system security.

- are based on reference year connection point data (retaining the same weekends and public holidays)[335]
- are consistent with the latest annual regional load forecasts prepared by AEMO or the TNSP
- are based on 50 per cent probability of exceedance and medium economic growth conditions
- include any known new loads
- include existing and committed generation that is embedded in the distribution network
- are an estimate of the active and reactive power at each connection point for each trading interval.

### B.2.3 Controllable network element flow data

Energy flows in a transmission network from generators to load centres and are generally passively distributed throughout the transmission network. The distribution of flows is predominantly determined by the impedances of the transformers and transmission lines, plus their topology. The exceptions to this are the Murraylink, Terranora and Basslink controllable network elements (DC links) where the flows on these links can be actively controlled through the AEMO dispatch process.

The Murraylink and Terranora network elements are regulated interconnections that operate in parallel with the Heywood and QNI[336] interconnectors respectively. In these cases the automated load flow program will determine the flows on these elements as a proportion of the Heywood and QNI flows.[337]

In contrast, the Basslink interconnector is an unregulated interconnector that operates as a market network service. To determine the flows on Basslink AEMO assumes that its flows are unchanged from the reference year (as required by clause 3.6.2(e)(6) of the NER).

### B.2.4 Generation data

In addition to the network model, the load data and the flows on controllable network elements, the automated load flow requires a set of generation data by connection point for each trading interval.

For the existing generating units, AEMO uses the generation data from the reference year.

For new generating units AEMO estimates generation data from similar existing generating units that have a known generation profile. In addition, AEMO assumes the dispatch of new committed generating units to be zero for trading intervals prior to the commissioning date reported in the latest ESOO.[338]

335 The reference year is previous financial year to the year when the loss factors are determined. For example, the 2019-20 loss factors are determined in the 2018-19 year and the reference year is 2017-18.

336 QNI is the Queensland to New South Wales interconnector.

337 See section 5.5.3 of AEMOs forward-looking loss factor methodology document.

338 The Commission understands AEMO sought subsequent commissioning updates from all committed generation proponents for this year's MLF determination.

Once commissioned, AEMO estimates the output of new generating units by shaping and scaling generation data from similar generating units that operated in the reference year data by:

- identify generating units in the NEM that use similar technology and fuel type (AEMO tries to only use data from generating units that are up to five years old, but does relax this to 10 years if no suitable data is otherwise available)
- find the average output of the similar generating units as a percentage of their winter rating from the reported in the latest ESOO
- determine the output of the new generating units by scaling the average output profile by the nameplate rating of the new generating unit.

Once a generating unit has been operating for two years AEMO will have sufficient actual data included in the relevant reference year.

Hydro and wind generating systems are rated differently as their output is energy constrained or intermittent. AEMO consults with the proponents of new hydro or wind generating units to determine an anticipated generation profile. Where the proponent is unable to provide a suitable profile, then AEMO uses a flat generation profile equal to the product of the anticipated utilisation factor and the nameplate rating of the generating unit. AEMO's methodology also includes a general approach to estimating the generation profile for new generating units that utilise a new technology or fuel type.

AEMO's determination of the generation data also needs to account for retiring generating units. Thus, AEMO sets the output to zero for generating units that are identified as retiring in the latest ESOO.

Finally, AEMO will also modify generation data when either AEMO or the associated generator considers that the operation during the reference year is unlikely to be representative of generation expected from a generating unit during the year that the inter-regional and intra-regional loss factors apply. This may occur for a number of reasons including significant droughts that limit the output of the generating unit, or prolonged outages for maintenance etc.[339]

### B.2.5 Restoring the supply and demand balance

In the reference year, the energy supplied by generation balances the energy consumed by the loads plus the losses in the network. However, this supply-demand balance will no longer occur for the year in which the inter-regional and intra-regional loss factors are being determined. This is because demand has been adjusted to account for load growth and new loads, and supply has been adjusted to account for new generation and generator retirement. In addition, network augmentations have been included and these may also affect the losses in the transmission network.

This supply-demand balance needs to be restored for the network flows to be representative of the flows in transmission network to be representative of the future financial year when

339 Additional details are available in section 5.5.6 of AEMOs forward-looking loss factor methodology.

the inter-regional and intra-regional loss factors will apply. To restore the supply-demand balance AEMO uses a process it calls the minimal extrapolation principle. This is done by adjusting the output of all the dispatchable generating units that are operating in that trading interval.

For periods of excess generation, where load has increased by less than the initial forecast of the output of the new generating units, AEMO reduces the net generation by scaling the output of all the generating units in proportion to their output in the reference year. AEMO does not adjust the output of energy limited generating units such as pump storage schemes.

For periods of insufficient generation, where load has grown by more than the initial forecast of the additional generation or due to generation retirement, AEMO increases the net generation. This is a more complex process than reducing the output of the generation as it needs to consider output limits on generating units and which units could have potentially operated at that time.[340]

When adjusting the generation to restore the supply-demand balance, the minimal extrapolation principle also needs to consider interconnector limits. Failure to consider interconnector limits could potentially result in flows that are beyond the secure limit of the interconnector and would not be representative of the network flows that could occur. Therefore, AEMO implements interconnector limits that are representative of the limits it expects to apply for summer and winter, and for peak and off-peak periods, for the financial year that the inter-regional and intra-regional loss factors will apply. AEMO consults with TNSPs when developing these representative limits. Considering the interconnector limits means that AEMO may need to adjust generation differently in different regions to maintain inter-regional flows within the respective transfer capabilities.

### B.2.6 Intra-regional loss factors

The automated load flow program solves for the network flows, and the associated loss, for each trading interval using the generation and load data described above. The loss factors for each load and generation connection point, with respect to their RRN, are extracted from the load flow solution for each trading interval. This results in 17,520 marginal loss factor values for each transmission connection point in the NEM.[341]

The intra-regional loss factor value for a given transmission connection point is the volume weighted average of the 17,520 intervals, where the weights are the energy generation and/or consumption values for each trading interval.

The use of volume weights to average the marginal loss factors for the trading intervals means that the resulting single intra-regional loss factor value is representative of periods of either high generation or consumption, for a generating unit or load connection point respectively.

340 Additional details on the process AEMO uses for period in insufficient generation are available in section 5.5.2 of AEMOs forward-looking loss factor methodology.

341 In a leap year there are 17,568 trading intervals due to the presence of 29 February.

Following the determination of the intra-regional loss factors for each of the transmission connection points, AEMO also calculates the loss factors for any VTNs.[342]

### B.2.7 Inter-regional loss factor equations

In addition to providing intra-regional loss factors for each trading interval, the automated load flow solution provides the inter-regional loss factors between the adjacent RRN.

Inter-regional loss factor equations are then determined for each interconnector by regressing the inter-regional loss factors for each trading interval against the interconnector flows by trading interval. The quality of the regression is improved by also including the regional demand values in the associated regions into the regression models.

342 Clause 3.6.2(b)(3) of the NER allows, with the agreement of the AER, for intra-regional loss factors to be averaged over an adjacent group of transmission network connection points. If averaging is used, the relevant transmission network connection points will be collectively defined as a VTN. The intra-regional loss factor for the VTN is calculated as the volume weighted average of the intra-regional loss factors of the constituent transmission network connection points. AEMO's forward-looking transmission loss factors methodology explains the specific method that it uses. VTNs are used for some connection points in New South Wales, South Australia and Tasmania.

# C OTHER LOSS FACTOR METHODOLOGIES

This appendix summarises other loss factor methodologies that have been considered by the Commission as part of this rule change process. This appendix includes discussion on:

- the cap and collar approach to loss factors
- grandfathering of MLFs
- the Irish compression model
- the Italian model to treating transmission losses
- determining dynamic loss factors.

## C.1 Cap and collar

The Commissions' consultation paper identified the cap and collar methodology as a potential approach to loss factors. Some stakeholders suggested that this could address the issues identified by Adani Renewables. The Commission provided an outline of how a cap and collar approach for loss factors could be implemented in the NEM. It noted that one such approach could be to apply a band within which all intra-regional loss factors must sit. For example, all loss factors must be between 0.8 and 1.1. Another approach to cap and collar identified was to apply a constraint to the change made to an intra-regional loss factor value by AEMO. For example, the maximum change to a loss factor is +/- five per cent.

Generally, the rationale for a cap and collar approach is that setting a limit within which loss factor values would sit would provide transmission connected market participants with a degree of certainty about how high or low their loss values would be. However, using a cap and collar may result in transmission loss factors that may not accurately reflect the loss of electricity from a transmission connection point to the RRN at all times or for all locations. As losses must always be accounted for, such a result would pass the cost of the lost electricity to consumers.[343]

### C.1.1 Stakeholder views on the request

Submissions received in response to the consultation paper indicated that there is almost no stakeholder support for changing the loss factor methodology to a cap and collar approach. While Origin noted that a cap and collar method would reduce variability of loss factors, it also acknowledged that the methodology would result in a shifting of risks and costs from new generation investment to consumers.[344]

Other stakeholders also noted that moving to a cap and collar methodology would:

- imply a move away from the current open access approach to transmission[345]
- socialise losses (or avoided losses) across consumers[346]

343 AEMC, *Transmission loss factors* consultation paper, 6 June 2019, pp. 18-19.

344 Submissions to the consultation paper: Origin, p. 5; EUAA, p. 3.

345 AEC submission to the consultation paper, p. 5.

346 Infigen submission to the consultation paper, p. 3.

- blunt locational signals currently provided by MLFs.[347]

The Commission received one submission supporting the cap and collar approach as a viable option. QIC Global Infrastructure submitted that cap and collar could provide a higher degree of certainty to market participants.[348]

PIAC suggested a methodology it called the insurance model. This model offers generators the option to purchase an insurance product in the form of an annually fixed MLF schedule with a ceiling and a floor.[349] In this respect the suggested model is similar to a cap and collar although it requires a counterparty to sell this type of insurance product. PIAC submitted that its suggested methodology would equalise the level of risk between participants compared to current arrangements where early connectors to the transmission system face significantly more risk. PIAC noted that under this model, AEMO would apply unbounded MLFs to determining the dispatch order for generators.[350]

### C.1.2 Draft rule determination

In the draft rule determination, the Commission formed similar conclusions to some stakeholders that, if implemented, a cap and collar methodology would be likely to:

- result in increased costs to all consumers in the NEM
- reduce locational signals provided by loss factors
- shift risk from new generation investment to consumers.

For these reasons, the Commission's draft rule determination conclusion was that introducing a cap and collar approach to transmission loss factors would not, or would not be likely to, contribute to the achievement ofh the NEO.

#### Impact on efficient investment

By limiting the up and down-side of MLF, the cap and collar would reduce volatility in MLFs. This would be likely to lead to more stable and predictable revenue and, all other things being equal, lead to a stable, if not lower, cost of capital.

However, applying a cap and collar to MLFs may be likely to induce additional investment in locations with relatively weak transmission infrastructure, increasing losses and congestion for the transmission network in the long run. These inefficient locational decisions could result in more losses which would flow through as higher costs to consumers.

#### Impact on efficient operation of providing electricity services

Similar to the analysis provided for average loss factors, the changing to a cap and collar would likely introduce inefficiencies into the provision of electricity services:

347 EnergyAustralia submission to the consultation paper, p. 9.

348 QIC Global Infrastructure submission to the consultation paper, p. 4.

349 PIAC submission to the consultation paper, p. 3. This methodology was also suggested to the AEMC in the context of the COGATI review.

350 PIAC submission to the consultation paper, p. 4.

- Using marginal pricing for dispatch and a cap and collar for MLFs will result in some market distortion. Similar to the analysis provided on the average loss factor approach, a cap and collar could impact on the merit order of dispatch resulting in generators with higher losses being dispatched.
- The ultimate impact on the merit order of dispatch will depend on which generators are online and which generators are marginal.

#### Risk allocation

The Commission's analysis indicates that applying a cap and collar to MLFs may result in a reduction in revenue volatility and result in a more stable and potentially lower cost of capital for owners of generators and prospective investors.

However, as stakeholders noted, a cap and collar would result in a shifting of risks and costs from new generation investment to consumers.[351]

The Commission acknowledges PIAC's insurance model aims to address risk allocation. However, the purpose of PIAC's insurance model seems to be to provide increased certainty for investors in generation projects in individual energy zones, with the option to applying the same methodology to the NEM. According to PIAC, this can be conceptualised as "smoothing within the generation fleet in the energy zone, so that the risk is somewhat equalised between participants.".[352] By placing a cap and collar on the MLF values, PIAC's suggested approach effectively transfers risk from some generators to others. This is because the returns of some generators are likely to be capped, while the potential losses of other generators would be limited by the floor on MLFs. It is also not clear how applying such an approach would impact on the IRSR.

### C.1.3 Public hearing

The cap and collar approach to transmission loss factors was not raised by stakeholders at the pre-final determination hearing.

### C.1.4 Stakeholder views on the draft determination

In response to the draft rule determination, PIAC disagreed with the Commission's assessment of its suggested alternative transmission loss factor approaches. It considered that the approaches "are worth further consideration including through any review by AEMO of its loss factor methodology".[353]

### C.1.5 Final rule determination assessment

No new information in regard to using a cap and collar approach to transmission loss factors has been provided to the Commission following its draft rule determination.

351 EUAA submission to the consultation paper, p. 3.

352 PIAC submission to the consultation paper, p. 4.

353 PIAC submission to the draft determination, p. 2.

In regard to PIAC's submission, the Commission considers that the suggested insurance model which, similarly limits loss factor values to within a range, would transfer risk between generators and impact on efficient operation of the NEM. As noted in the draft rule determination, the Commission is also concerned about how PIAC's suggested approach interacts with the IRSR and consequently, electricity consumers.

In the draft rule determination, the Commission noted that in general, applying a cap and collar approach to transmission loss factors may provide a stable (and potentially reduced) cost of capital to investors in generation assets. It would reduce variability in loss factors which could provide benefits to debt and equity investors, in terms of more funding availability and a reduced cost of capital.

However, any benefits experienced by investors in generation assets would be likely to be outweighed by less efficient investment, dispatch and risk allocation. That is, any benefits would be at the expense of consumers because applying a cap and collar would transfer some of that loss factor risk from generators to consumers, who are not best-placed to manage them. This would result in inefficiencies and higher costs to consumers.

### C.1.6 Final rule determination

As set out in the draft rule determination, on balance, the Commission considers that the use of a cap and collar for determining transmission loss factors in the NEM would not represent an improvement in the transmission loss factor framework, and accordingly, would not (or would not be likely to) contribute to the achivement of the NEO.

## C.2 Grandfathering

In its consultation paper, the Commission asked stakeholders if grandfathering of MLFs year-on-year could address the current volatility in MLFs. In doing so, it noted:[354]

- Locking in the MLF value for a generator would allow operators and investors in generation assets to better predict and manage the financial risk of MLF variability.
- Lower MLFs, capturing the full effect of the additional losses resulting from the connection of a new generator, would apply to new transmission connections.
- Grandfathered MLFs may not lead to efficient investment decisions and may create barriers to entry for new generators.

### C.2.1 Stakeholder views on the request

Submissions from stakeholders made in response to the consultation paper indicated that there was little interest in applying grandfathering to transmission loss factors. PIAC suggested a modified model of grandfathering could be used to provide stronger investment signals. However, other stakeholders opposed grandfathering on the basis that it would result in an inefficient wholesale market.

354 AEMC, *Transmission loss factors,* consultation paper, 6 June 2019, p. 19.

Origin submitted that, in its opinion, grandfathering would result in inefficient dispatch.[355] Similarly, ERM Power submitted that while grandfathering of loss factors for existing generators could sharpen locational signals for new generators to more accurately calculate their true marginal impact on overall system losses, the use of grandfathered losses could also act as a barrier to the efficient entry of new generation or retirement of existing generation.[356] EnergyAustralia and Baringa also noted that grandfathering would result in absolute certainty in MLFs (depending on length of grandfathering) at the expense of any accuracy or potential locational signals.[357]

The Investor Group did not support grandfathering, noting that it would have the potential to "distort investment signals and discourage future investment signals and discourage future investment in generation."[358] MUFG Bank considered that setting a floor for MLFs would provide a better model than grandfathering.[359]

However, QIC Global Infrastructure stated that the application of grandfathering principles could contribute to a higher degree of confidence for market participants.[360]

PIAC suggested a variant of the grandfathering model which locks-in particular MLFs for a set period-of-time.[361] It claimed that this model would provide a stronger investment signal for connecting generators by allowing connecting parties to have their MLF 'locked in' by AEMO for a standard period-of-time. This would provide the owner of the generator greater certainty of its future revenue. The necessary design decisions to implement this approach would include determining an appropriate sunset period for a grandfathered MLF value.

Under PIAC's grandfathering approach, if a new party were to connect near an existing generator and affect the local MLF, the change in the MLF would be borne by the second party alone rather than being spread across both parties. In PIAC's opinion, this approach provides a much stronger signal to each new connecting generator to minimise their impact on overall loss factors, such as by incorporating storage. Once the determined period-of-time has elapsed, the MLFs are no longer 'locked in' and the revised loss factor at the connection point would be applied to both parties.[362]

### C.2.2 Draft rule determination

In the draft rule determination, the Commission commented that applying grandfathering to transmission loss factors would be likely to:

- act as a barrier to entry for new generation
- reduce accuracy of loss factor values

355 Origin submission to the consultation paper, p. 5.

356 ERM Power submission to the consultation paper, p. 5.

357 Submissions to the consultation paper: EnergyAustralia, p. 9; CEC supplementary submission: Baringa report, p. 24.

358 Investor Group submission to the consultation paper, p. 17.

359 MUFG Bank submission to the consultation paper, p. 4.

360 QIC Global Infrastructure submission to the consultation paper, p. 4.

361 Baringa also noted that grandfathering could be used for a set period. CEC supplementary submission to the consultation paper: Baringa report, p. 24.

362 PIAC submission to the consultation paper, pp. 5-6.

- distort locational signals of loss factors
- result in inefficient dispatch of generators in the NEM.

Consequently, the Commission concluded that applying grandfathering to transmission loss factors would be unlikely to better contribute to the achievement of the NEO than the current marginal loss factor approach.

In forming this conclusion, the Commission considered PIAC's suggested methodology of a time-limited lock-in model for MLFs. Under this approach, connecting parties would have their MLFs locked in for a standard period-of-time and that:

- New entrants that connect to the transmission network and affect the local MLF would bear the full change in the MLF at that location. For example, an incumbent generator with a locked-in MLF of one would retain its MLF, and the newly connected generator would have its MLF value calculated based on the losses associated with its own generator and the incumbent generator until the incumbent's MLF is unlocked.
- Once the determined period-of-time for generator one has expired, the MLF at the connection point would be unlocked and generators one and two would receive revised MLFs reflecting forecast marginal losses.

PIAC's suggested limited period for grandfathering MLFs is an advantage over a lifetime approach to grandfathering. However, the likely implications of applying limited period grandfathering to MLFs, including inefficient dispatch, barriers to entry for new generation and distorted locational signals, are just as relevant as they are for long term grandfathering. On balance, these effects outweigh the positive impacts that may arise for current investors in generation assets.

#### Impact on efficient investment

The grandfathering of MLFs would be likely to result in inefficient investment because owners and investors of new generation assets may be deterred by the higher losses attributed to them compared to incumbent generators holding grandfathered MLFs. Incumbent generators would benefit from a lower cost of capital arising from certainty in MLF values. However, new entrants will bear the cost of a higher cost of capital.

#### Impact on efficient operation of providing electricity services

Grandfathering may act as a barrier to entry for new generators. As a result, the operation of the NEM would be less efficient because it could prevent more efficient lower cost generators from entering the market.

#### Risk allocation

Grandfathering of MLFs would be likely to shift the risk of high or variable loss factors from incumbent generators to new entrants and ultimately to consumers. The effect of this would likely be that:

- consumers would pay more for electricity services because less efficient generation assets supply the market in response to less accurate MLFs

- more efficient lower cost generation would be deterred from entering the market because they are facing the full loss factor risk on a transmission line when connecting.

### C.2.3 Public hearing

The application of grandfathering to MLFs was not raised by stakeholders at the pre-final determination hearing.

### C.2.4 Stakeholder views on the draft determination

Only one stakeholder commented on grandfathering in response to the Commission's draft rule determination.

PIAC noted that in its previous submission, it had suggested changing the framework so that MLF values are locked-in for a specified time. It disagreed with the Commission's draft rule determination and stated that its suggestion was "worth further consideration including through any review by AEMO".[363]

### C.2.5 Final rule determination assessment

As set out above and in the draft rule determination, the Commission considers that PIAC's suggested time-limited grandfathering of MLFs would have the potential to advantage owners of incumbent generation assets at the expense of new generators and, ultimately electricity consumers.

### C.2.6 Final rule determination

Consistent with its draft rule determination, the Commission has concluded that while grandfathering MLFs (even for a specified period) may create some benefits to owners of existing generation assets it would be likely to create undesirable distortions in the NEM. In particular, prospective investors and owners of new, more efficient, generators may be deterred from entering the market because of the lower MLF values that would be allocated to them.

As a result, the Commission is not satisfied that grandfathering MLFs would, or would be likely to, contribute to the achievement of the NEO.

## C.3 Irish compression model

The single electricity market (SEM) in Ireland and Northern Ireland uses a unique approach to transmission loss factors, which has become known as the "compression" model. The Investor Group suggested the Irish compression methodology could be used to determine loss factors in the NEM, although it was not their preferred model.

The Irish compression approach is to derive a single volume-weighted marginal loss factor value for a financial year for a given transmission connection point. The single electricity market operator (SEMO) then applies a compression factor which has the effect of limiting

363 PIAC submission to the draft determination, p. 2.

the spread of values for loss factors assigned to connection points. Figures D.1 and D.2 set out how the Irish compression model is computed.

Firstly, the MLF value for each transmission point is calculated using the formula in Figure D.1. The algorithm is then normalised around the normalisation number (NN) as shown in Figure D.2. A NN is calculated for each scenario and is a point of reference for the loss factors to be compressed around. The NN is chosen so that, after compression is applied, the compressed losses are equal to the uncompressed losses (the forecast transmission losses for a month). In the SEM, the NN is approximately 0.98, but varies depending on the losses for each month and day and night. The effect of applying a compression factor is to reduce the range of the loss factors applied to connection points such that the effects of loss factor value volatility are reduced by approximately 50 per cent.

**Figure C.1: Irish compression model — calculating the MLF**

$$\frac{\Delta\, total\ system\ demand}{average\ of\ absolute\ value\ of\ +\Delta G\ and\ -\Delta G}$$

Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.

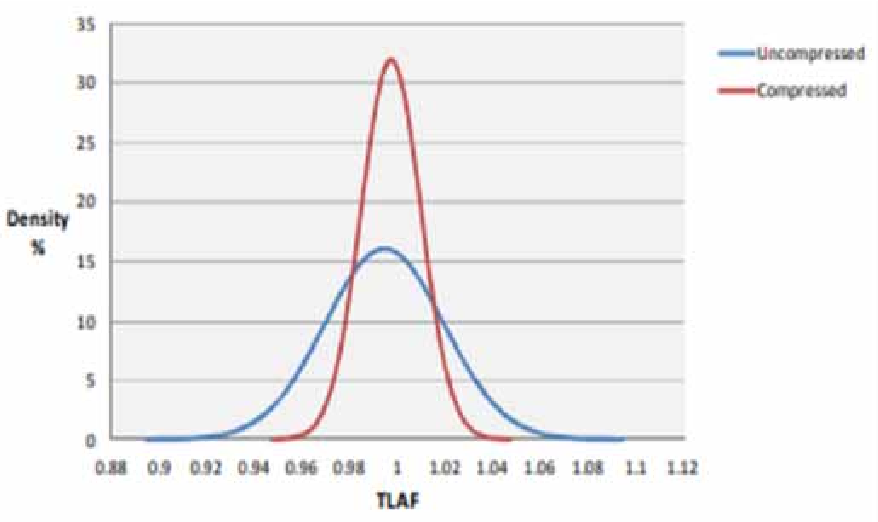
**Figure C.2: Irish compression model — compressing the MLF**

$$if\ X < NN,\ \frac{NN-X}{2*NN}+X;\quad if\ X > NN,\ X-\frac{X-NN}{2*NN}$$

Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.
Note: X=the uncompressed loss factor (MLF) and NN=normalisation number.

EirGrid (the Irish transmission network operator) and SONI (the system operator for Northern Ireland) have illustrated the effect of applying the transmission adjustment loss factor (TLAF) in the graph below. It shows how the distribution of loss factors under the compressed methodology moves closer to unity resulting in less volatility. However, the graph also shows that by compressing the loss factors, locational signalling is likely to be reduced.

**Figure C.3: Effect of applying the compression model (TLAF)**




Source: EirGrid and SONI, *Explanatory Paper for Transmission Loss Adjustment Factor Calculation Methodology (TLAF)*, September 2012.

### C.3.1 Stakeholder views on the request

The Investor Group submitted that the Irish compression model was its second option to change the MLF framework in the NEM.[364] PARF made similar comments in its submission.[365] The CEIG considered that the Irish compression model would be likely to:

- reduce volatility of revenue for existing generators
- reduce over-recovery of IRSR
- increase investment certainty and bankability of future renewable energy projects
- mitigate the risk of cost of capital risk premia to compensate for increased loss factor volatility.

While the Investor Group found this option to have a similar impact as the average loss factor, it preferred the average methodology because using the Irish compression model would be:[366]

- relatively complex to understand and implement
- less reflective of actual losses
- sensitive to the value assumed for the normalisation value.

364 CEIG submission to the consultation paper, p. 11.

365 PARF submission to the consultation paper, p. 12.

366 Investor Group submission to the consultation paper, p. 12.

In its submission, Hydro Tasmania noted that a loss factor methodology which more closely than the marginal methodology aligns loss factors to reflect actual losses deserves attention. It suggested that one of such a methodology could be the Irish compression model.[367]

The CEC's consultant, Baringa, suggested that both compressed MLFs and average loss factors would reduce the cost of capital for new investment and enable more projects to be financially viable.  Baringa stated that according to its analysis, both options, compressed MLFs and average loss factors, could support the development of new generation capacity at least cost by providing generators stronger revenues and maintaining more favourable loss factors as the capacity of new build increases. The effects of using a compression MLF model, according to Baringa, include:[368]

- greater certainty because compressed MLFs are likely to vary less
- dampened locational signal
- dispatch efficiency preserved albeit less marginal losses are factored in
- reduced forecast error
- reduced IRSR.

### C.3.2 Draft rule determination

In its draft rule determination, the Commission commented that one benefit of the Irish compression model is that it would be likely to result in more stable and, for some generators, higher loss factors compared to MLFs. However, it would also be likely to create reductions in the locational signal, which could result in higher costs to consumers in the long-term.

#### Impact on efficient investment

While the Irish compression model may aim to preserve the merit order as under a pure MLF approach, the absolute values of the loss factors would be altered, reducing their effectiveness as signals to incentivise efficient investment in generations and transmission. The effect would be similar to a cap and collar approach; the compression model would be likely to induce investment in locations with weaker transmission infrastructure, increasing physical transmission losses and resulting in higher costs to consumers in the long run.

The Irish Single Electricity Market Committee (SEMC), published its decision on the treatment of losses in the SEM in June 2012.[369] This decision document noted that as part of its consultation process, the SEMC had published a proposed decision paper for consultation. It received seven submissions from generators and retailers in response.  None of the stakeholder submissions favoured the compression model. The stakeholders argued that all the compression approach achieves is the removal of extremities of the existing loss factor methodology (TLAFs). Stakeholders also commented that maintaining the compression

367 Hydro Tasmania submission to the consultation paper, p. 2.

368 CEC supplementary submission to the consultation paper, p. 18.

369 SEMC, *Treatment of losses in the SEM*, decision paper, 26 June 2012.

methodology on an ongoing basis perpetuates the methodology which had been under scrutiny in the first place.[370] Stakeholder submissions argued for locational signals (the TLAF methodology) or fixed loss factors.

### Impact on efficient operation of providing electricity services

The compression model is intended to result in the same merit order of dispatch as would be the case as using uncompressed MLFs, even as the absolute range of loss factors is reduced. However, it is not clear that this would be the result in all circumstances. As a result, the impact of the compression model on the efficient operation of generators is uncertain.

### Risk allocation

The Irish compression model would be likely to shift risk, both between generators and customers and between different generators. As noted by the CEC in its supplementary submission to the consultation paper, applying a compression model would be likely to result in:[371]

- a reduction in the settlement residue and therefore a smaller reduction in TUOS charge passed through to consumers, resulting in relatively higher bills
- reduction of loss factors for MLFs that are larger than the compression number.

The compressed loss factor values would be likely to lead to:

- more stable and higher loss factors for some generators, which might reduce their cost of capital
- lower compressed loss factors for some generators (those having an MLF greater than the compression factor), which could result in less revenue and potentially a higher cost of capital.

These changes indicate a reduction in the effectiveness of the MLF locational signal which could result in higher costs to consumers in the long-term. This is because:

- there would be at least some risk transferred from remote generators to generators located closer to load centres
- dampening the locational signal may incentivise new entrant generators to locate further away from load, increasing total losses.

The draft rule determination included some analysis carried out by the Commission to estimate the impact of a change to a compression methodology on generators. The Commission recalculated loss factors of generators in the NEM using the Irish compression model and using a compression number of 0.97.[372] This analysis indicated that a change to the use of a compression model to determine transmission loss factors would be likely to result in some generators enjoying a relatively higher loss factors (compared to under the current MLF methodology) and therefore higher revenue. However, other generators would

370 SEMC, *Treatment of losses in the SEM*, decision paper, 26 June 2012, p. 5.

371 CEC supplementary submission to the consultation paper, pp. 18-19.

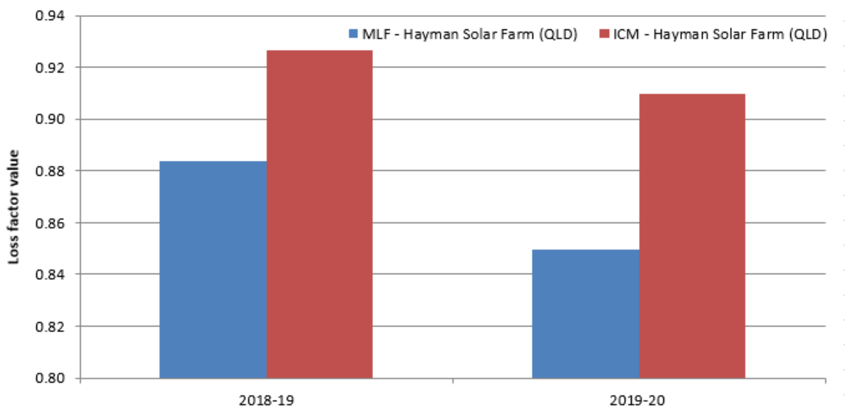
372 This number was used as CEC proposed a compression number of 0.97-0.98 based on 2019-2020 MLFs for all generation and load. CEC supplementary submission to the consultation paper, p. 20.

experience a reduction in their MLF value and hence revenue. That is, the change from the current MLF methodology to a compression model would have the effect of redistributing revenues between generators.

For example, Figure D.4 shows the marginal and compressed loss factors for Hayman solar farm in Queensland and Figure D.5 shows the marginal and compressed loss factors for Sun Metals solar farm, also in Queensland. These figures demonstrate how applying a compression model can increase the loss factor for generators with an MLF lower than the compression factor and also reduce the loss factor for generators with an MLF higher than the compression factor. For 2018-2019 and 2019-2020, applying a compression model would:

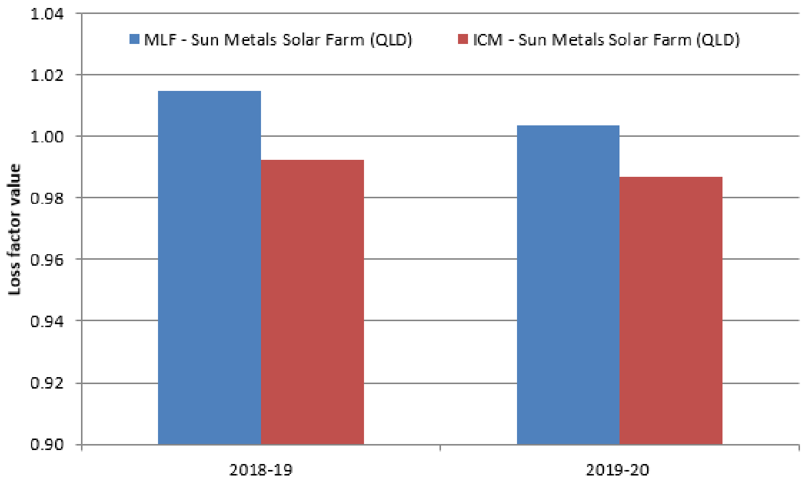
- increase (compared to an MLF) the loss factor for Hayman solar farm by five and seven per cent respectively
- decrease (compared to an MLF) the loss factor for Sun Metals solar farm by two per cent in both years.

**Figure C.4: Applying a compression model Hayman solar farm Queensland**




Source: AEMO, AEMC.
Note: Compressed loss factors calculated using a compression factor of 0.97.

**Figure C.5: Applying a compression model Sun Metals solar farm Queensland**




Source: AEMO, AEMC.
Note: Compressed loss factors calculated using a compression factor of 0.97.

### C.3.3 Public hearing

Use of the Irish compression model for transmission loss factors was not discussed by stakeholders at the pre-final determination hearing.

### C.3.4 Stakeholder views on the draft determination

No submissions responding to the draft rule determination commented on the Irish compression model.

### C.3.5 Final rule determination assessment

No additional information on the Irish compression model has been provided to the Commission following publication of the draft rule determination. The Commission considers that its assessment in the draft rule determination remains appropriate.

### C.3.6 Final rule determination

As stated in the draft rule determination, the Commission considers that the use of the Irish compression model for determining transmission loss factors in the NEM would be unlikely to be an improvement in the transmission loss factor framework and so be unlikely to contribute to the achievement of the NEO. This is the case, because:

- there would be at least some risk transferred from remote generators to generators located closer to load centres
- dampening the locational signal may incentivise new entrant generators to locate further away from load, increasing total physical losses
- compressed loss factors are likely to ultimately result in higher costs for consumers.

## C.4 Italian model

Enel Green Power suggested that the Commission have regard to the Italian approach to determining loss factors. The key principle for this approach is that the "end-user of electricity or their Retailers should bear the full cost for losses, while the Network operators buys the extra-energy needed to front the losses".[373] Enel Green Power noted that the Italian market is relevant because it has faced a rapid renewables penetration over the last 10 years, similar to what is currently occurring in Australia.[374]

**BOX 2: TRANSMISSION LOSSES IN THE ITALIAN ELECTRICITY MARKET**

The Italian wholesale electricity market operates using a power exchange and bilateral contracts. The treatment of losses is based on the principle that "load" (end-users of electricity or the suppliers representing them) should bear the cost of the losses.

Customers pay for a quantity of electricity that includes what is used as well as the loss incurred to transport that electricity and an error factor.

With respect to cost allocation of transmission losses:

- In the day-ahead market, losses are priced at the energy clearing price.
- The difference between the day-ahead estimation of losses and the actual level of losses is paid by the Italian transmission service operator (TERNA) at the balancing price in real time and recovered by all customers through network tariffs.

Source: INOGATE, *EU practice in treatment of technical losses in the high voltage grid*, January 2012.

### C.4.1 Stakeholder views on the request

No stakeholder other than Enel Green Power suggested or commented on the Italian approach to transmission loss factors.

In its submission, Enel Green Power agreed with Adani Renewables that the loss factor methodology should be changed. It suggested that the AEMC look at a European example, in particular the Italian model, to calculate loss factors.[375] The Italian model uses ex-ante loss factors and the transmission company is pays for the difference between estimated and actual losses.[376]

Enel Green Power commented that the Italian model of regulating transmission infrastructure has been in place for a long time and has proven to be effective in facilitating rapid renewable penetration. It also noted that in Italy:

- ex-ante loss factors are periodically updated by the Italian Regulation Authority.

373 Enel Green Power submission to the consultation paper, p. 5.
374 Enel Green Power submission to the consultation paper, p. 1.
375 Enel Green Power submission to the consultation paper, p. 1.
376 Enel Green Power submission to the consultation paper, p. 5.

- the difference between estimated and actual losses is paid by transmission system operator at the market price and passed through to all customers
- a liability is periodically computed as the difference between actual and estimated costs
- this difference is owed to or by the distribution network operator.

Enel Green Energy suggested that because generators are excluded from the risk of transmission losses, they are able to provide electricity at the cheapest price.[377]

### C.4.2 Draft rule determination

The Commission considered the Italian model as suggested by Enel Green Power. In the draft rule determination, it stated that it wouldn't be possible to adopt a similar model in Australia without undertaking other substantial changes to the NEM which are outside the scope of the current rule change process and which would have significant impacts on the operation of the NEM.

In addition, the Commission considered that a significant drawback of the approach is that it does not provide locational signals to site new generators. As discussed in draft rule determination and in the COGATI review, this is a desirable feature for the NEM.

### C.4.3 Public hearing

The Italian model for managing transmission loss factors was not raised by stakeholders at the pre-final determination hearing.

### C.4.4 Stakeholder views on the draft determination

No stakeholder submissions discussed the Italian model for transmission losses.

### C.4.5 Final rule determination assessment

No additional information on the Italian model for transmission losses has been provided to the Commission following publication of the draft rule determination. The Commission considers that its assessment in the draft rule determination remains appropriate.

### C.4.6 Final rule determination

As stated above and in the draft rule determination, implementing the Italian model for the purpose of managing transmission losses would require a considerable amount of reform to other pricing frameworks and market mechanisms which are outside the scope of this rule change.

## C.5 Dynamic loss factors

The Commission's COGATI review is seeking to determine how best to coordinate generation and transmission investment in the NEM. This project is broader in scope than this rule

377 Enel Green Power submission to the consultation paper, p. 5.

change process and includes considering significant market reforms such as the introduction of dynamic loss factors and financial hedging arrangements.

The Commission notes that in some overseas markets where there are locational marginal prices, MLFs are calculated dynamically at each location in real-time. As a result, significant reforms to the transmission loss factor framework, including consideration of moving to the more efficient dynamic loss factor approach, are best considered along-side the development of reforms to the access arrangements in place for the transmission system.[378]

### C.5.1 Stakeholder views on the request

Several stakeholders expressed an interest in further consideration of dynamic loss factors. Engie suggested that the Commission should provide analysis of the multiple MLFs approach and five-minute dynamic loss factors in terms of cost, dispatch efficiency and risk management to inform stakeholders in their assessment of various approaches.[379]

IES submitted that while it does not support Adani Renewables' proposal to use average loss factors, it considered that the current MLF arrangement does need to be upgraded. In its view, the analytical market design constraints that existed when MLFs were developed no longer apply and that the best way forward is to calculate and apply MLFs in real time.[380] IES further submitted that "realistic MLFs would sharpen operational and investment signals by lowering off-peak prices and increasing peak prices."[381] As a result, IES considered that the NEM should move towards implementing dynamic marginal losses in real time as this would better achieve the NEO and remove AEMO from direct involvement in the market.[382]

Similarly, supporting a change to dynamic loss factors, EPSDD submitted that the NER should be amended to remove the requirement that AEMO produce loss factors that apply for a whole financial year. AEMO should be instead required to publish one or more loss factors, and the associated time period(s) in which they apply, for the next financial year. This should require AEMO to ensure each connection point has a loss factor in place for the whole financial year. In EPSDD's opinion, this would allow, but not require, AEMO to implement dynamic loss factors. Such changes would enable AEMO to strike an appropriate balance between the simplicity of having a smaller number of loss factors, with the accuracy of a larger number. This may result in loss factors applying for broad time periods such as 'winter nights', 'summer days' and would not necessarily require a separate loss factor for every five minute interval.[383]

ENA submitted that it prefers a move to dynamic loss factors, and in the meantime, more frequent updating and publication of the loss factor values would be an improvement.[384]

378 AEMC, *Transmission loss factors*, consultation paper, 6 June 2019, p. 14.
379 Engie submission to the consultation paper, p. 3.
380 IES submission to the consultation paper, p. 1.
381 IES submission to the consultation paper, p. 2.
382 IES submission to the consultation paper, p. 6.
383 EPSDD submission to the consultation paper, p. 6.
384 ENA submission to the consultation paper, pp. 5-6.

AusNet Services submitted that while supporting a move to universally applied dynamic MLFs, it would also see value in allowing generators and market customers to opt-in to dynamic MLFs as an interim step. Under this approach the opting-in market participant is allocated a dynamic MLF for each trading interval, within a week of the trading interval.[385]

In contrast, Mondo submitted that it does not support moving to a dynamic MLF framework. It noted that it seems inevitable that to manage a volatile MLF, market participants would need to come to some agreement in advance of the likely average MLF over the period, and then agree on a calculation to deal with the 'unders' and 'overs' introduced by the dynamic MLF.  Mondo noted that if its observation is correct, then it raises the question of what is the value of the dynamic MLF, if it then needs to be effectively 'averaged away' by market participants.[386]

### C.5.2 Draft rule determination

The Commission considered stakeholder submissions on dynamic loss factors and reiterated that a potential change to dynamic marginal loss factors is best considered along-side broader reforms. This is because changing to a dynamic loss factor would involve considerable changes to other market mechanisms outside the scope of this rule change such as transmission access arrangements and charging . These are currently being considered as part of the Commissions COGATI review and the ESB's post market 2025 review.[387]

The Commission acknowledged that it is theoretically possible to compute dynamic loss factors, and that this could achieve market efficiencies. It also noted that the introduction of dynamic loss factors would be likely to require significant, costly changes to AEMO's systems. Accordingly, such a change is unsuitable as a short-term change that could be made before the introduction of further, more fundamental changes that may be made through the implementation of reforms identified in the COGATI review. Nor should it be considered without further regard to other changes to wholesale electricity pricing in the NEM.

The draft rule determination noted that dynamic marginal loss factors are likely to achieve market efficiencies for the NEM. However, their use also introduces a higher level of variability.  In the absence of any appropriate complementary hedging mechanism being introduced at the same time (for example, financial risk management options as being contemplated under the COGATI review), this could, all other things being equal, lead to unintended consequences. The Commission noted these important flow-on effects warranted further consideration.

Consequently, the introduction of dynamic loss factors would require changes to be made to the NER which are beyond the scope of this rule change process. Such changes should be considered holistically as part of the broader reforms to the transmission access framework being considered by the ESB and by the Commission in its COGATI review.

385 AusNet Services submission to the consultation paper, p. 1.

386 Mondo submission to the consultation paper, p. 9.

387 AEMC, *COGATI directions paper*, 27 June 2019, pp. 25-34.

### C.5.3 Public hearing

At the pre-final determination hearing, Innogy referred the Commission to a paper that reviewed various electricity market approaches to providing locational signals to prospective investors of generators.[388] It highlighted the paper's comments that useful investment signals arise from predictable, transparent price signals. Accordingly, Innogy argued that the introduction of dynamic loss factors was not consistent with the paper's conclusions.[389]

### C.5.4 Stakeholder views on the draft determination

In regard to this rule change process, two stakeholder submissions referred to dynamic loss factors:

- TasNetworks stated that one reason why it did not favour the change to average loss factors was that it would move the market further away from the long term direction of using dynamic loss factors which it supports.[390]
- EnergyAustralia commented that the draft rule amendment to the current 30-minute interval requirement for calculating transmission loss factors in clause 3.6.2(e)(2) of the NER appeared to contradict the Commission's preference for an eventual change to dynamic loss factors.[391]

In addition, other stakeholder submissions noted the Commission's consideration of dynamic loss factors as part of its COGATI review:

- Engie requested that the Commission provide analysis of the various loss factor approaches, including dynamic loss factors, with respect to cost, dispatch efficiency, locational signals and risk management to inform stakeholders.[392]
- Snowy Hydro noted the draft rule determination comments on the complexity of introducing dynamic loss factors and stated that it expected that the "adoption of dynamic loss factors on their own would introduce additional uncertainty increasing risk, which would lead to additional cost".[393] It considered that scheduled generators would be particularly impacted.

### C.5.5 Final rule determination assessment

In regard to the comments made by TasNetworks, the Commission notes it is similarly concerned that the use of average loss factors would create transitional issues if there were more significant changes to the loss factor framework in the near future.

The concerns express by EnergyAustralia are addressed in Chapter 6 of this final rule determination.

388 A Eicke, T Khanna, L Hirth, 'Locational investment signals in electricity markets — How to steer the siting of new generation capacity?', ZBW–Leibniz Information Centre for Economics.

389 AEMC transcript of the pre-final rule determination hearing, p. 10.

390 TasNetworks submission to the draft determination, p. 2.

391 EnergyAustralia submission to the draft determination, p. 2.

392 Engie submission to the draft determination, p. 2.

393 Snowy Hydro submission to the draft determination, p. 2.

### C.5.6 Final rule determination

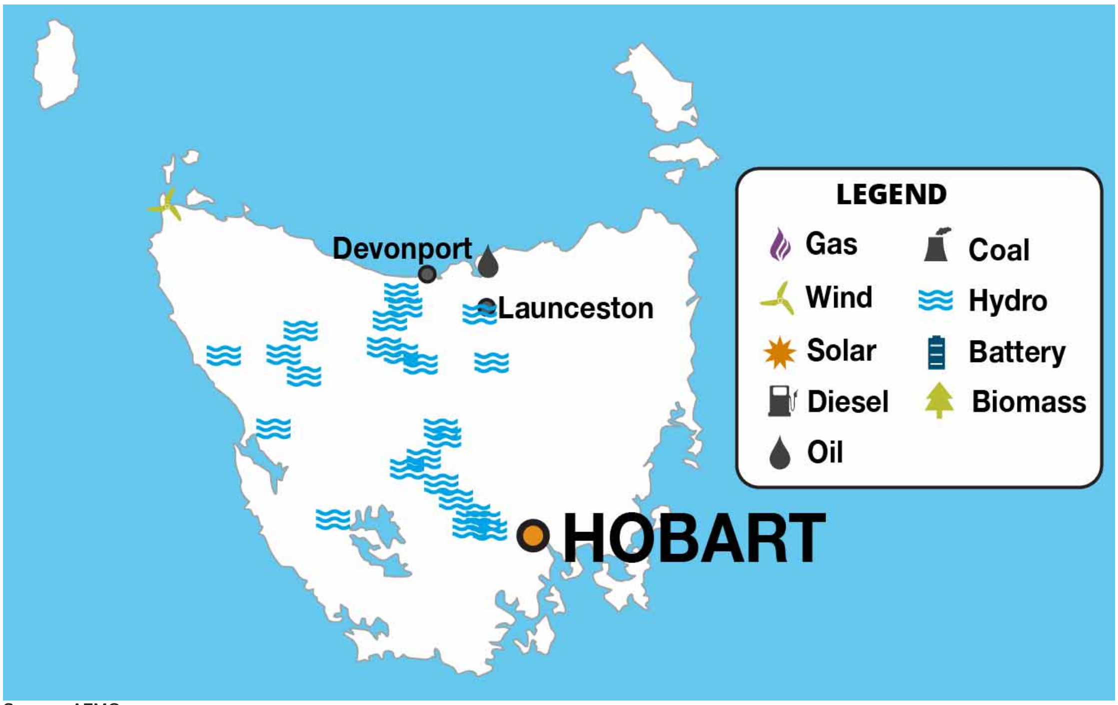
As set out in the draft rule determination, the Commission considers that the introduction of dynamic loss factors would require changes to be made to the NER which are beyond the scope of this rule change process. Instead, the Commission and ESB are considering such changes as part of broader reforms to be made to the transmission access framework in the future.

# D CHANGE IN GENERATION MAPS

The information contained in these maps, including the location and generation type, has been prepared by the AEMC as a general guidance and for information purposes only. The information is based on publicly available sources, and has not been independently verified by the AEMC, and therefore, may not be complete, accurate or up to date.

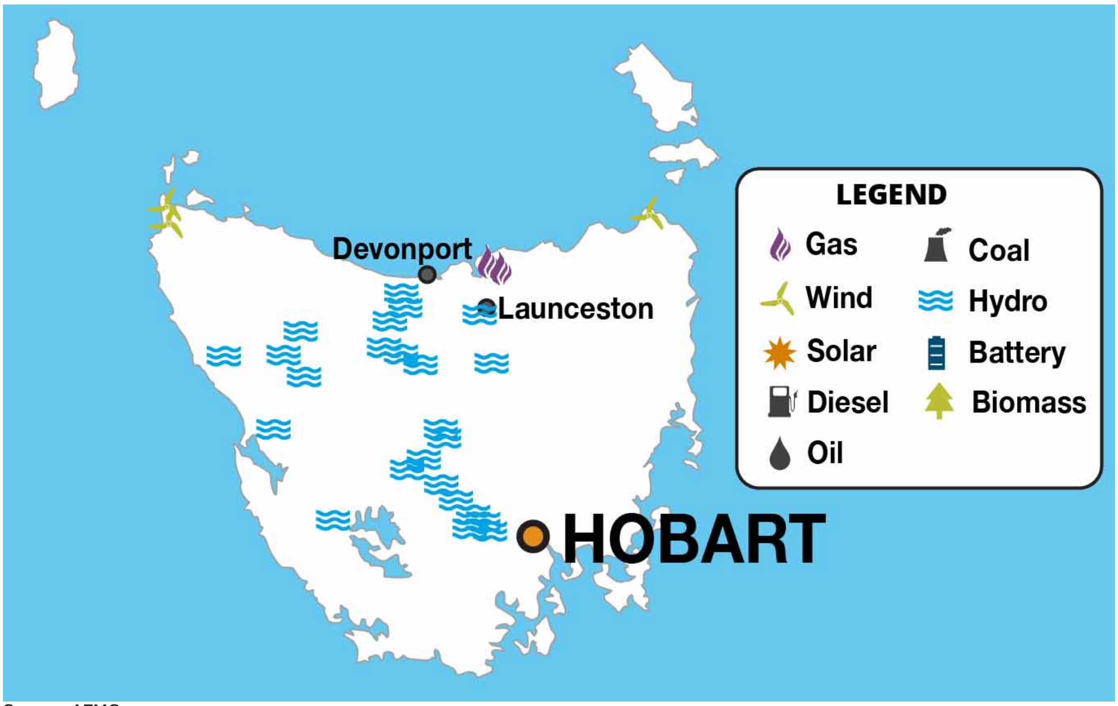
## D.1 Tasmania

**Figure D.1: Location of generation in Tasmania 2002**




Source: AEMC

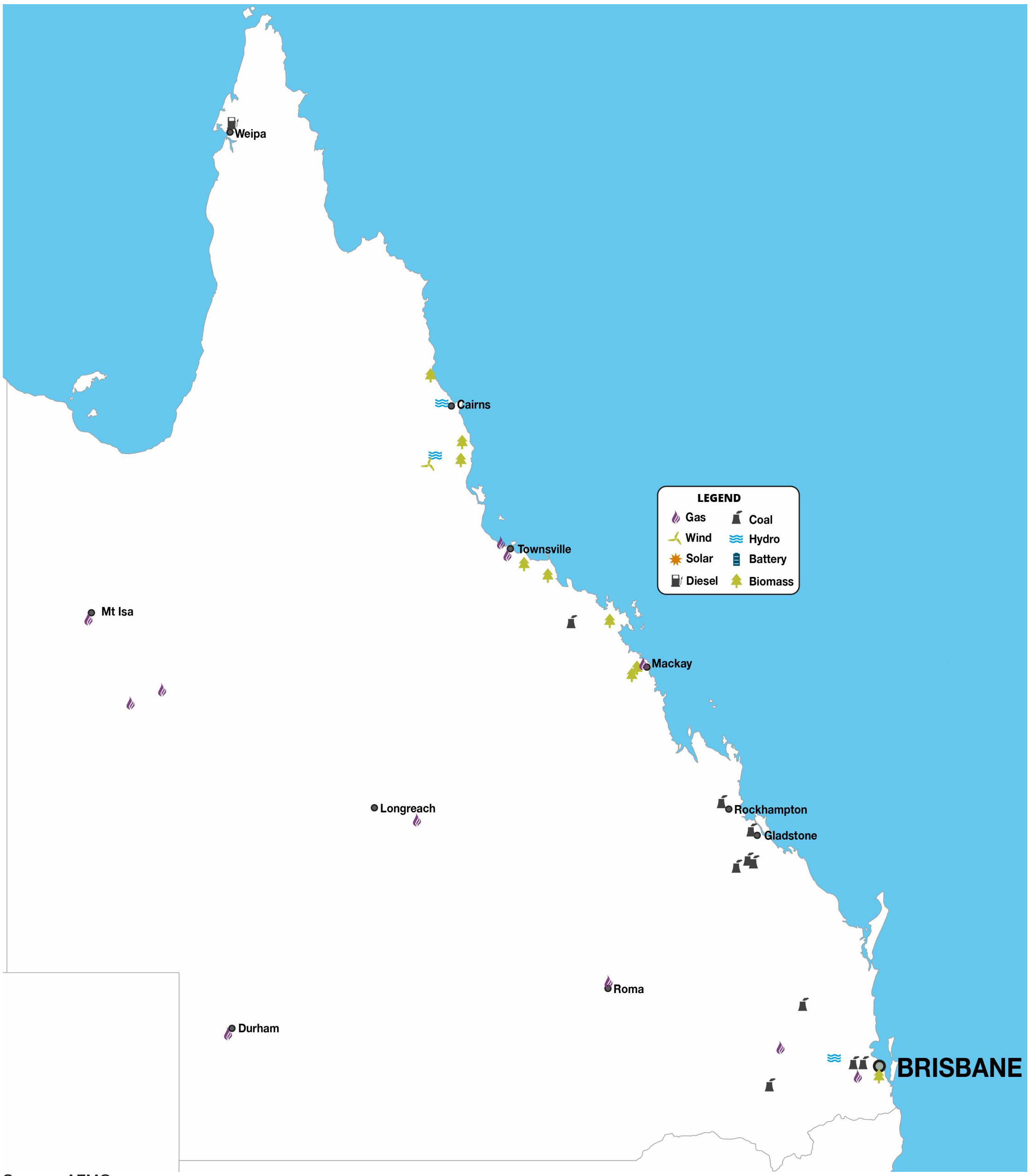
**Figure D.2: Location of generation in Tasmania 2019**




Source: AEMC

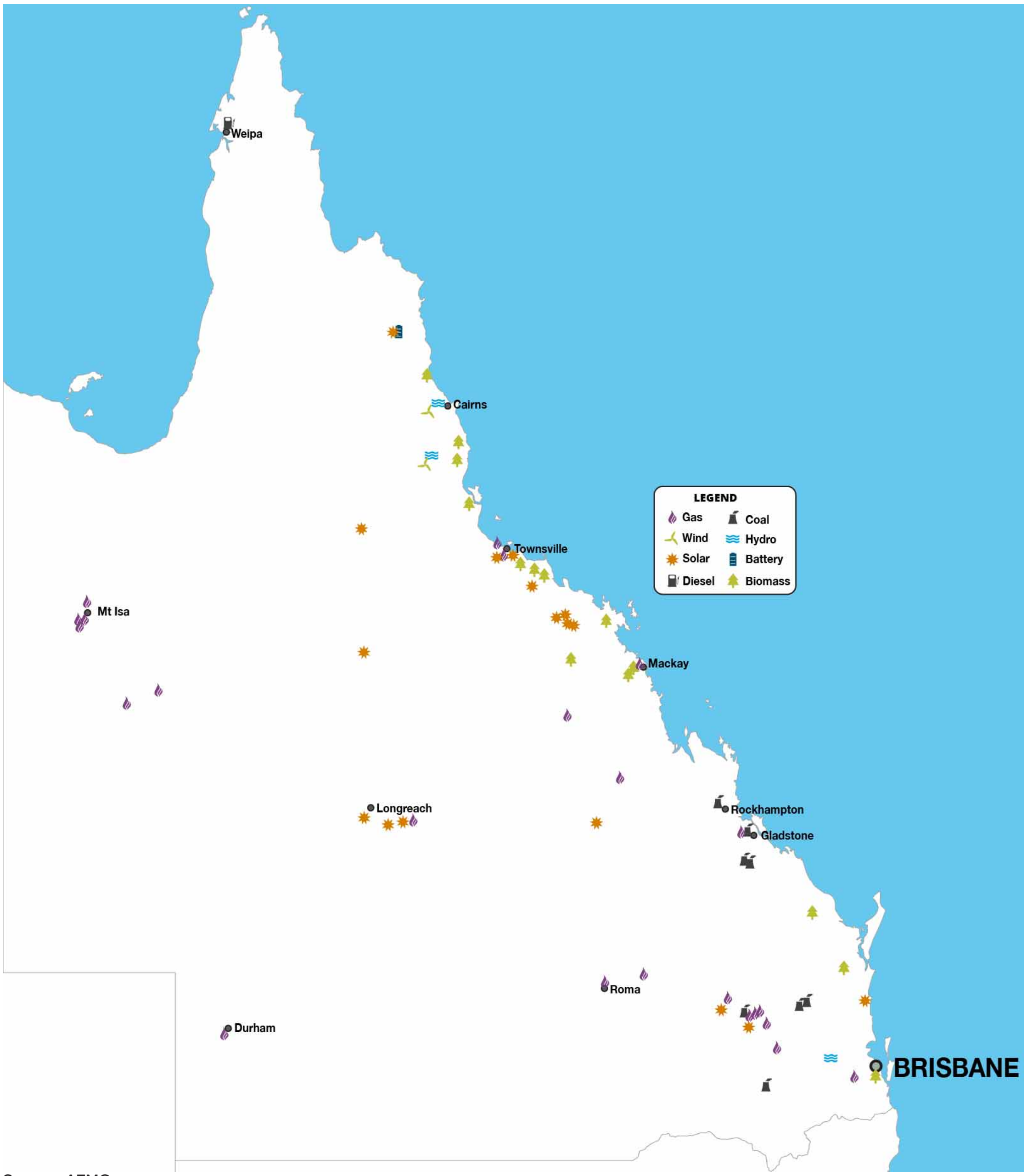
## D.2 Queensland

**Figure D.3: Location of generation in Queensland 2002**




Source: AEMC

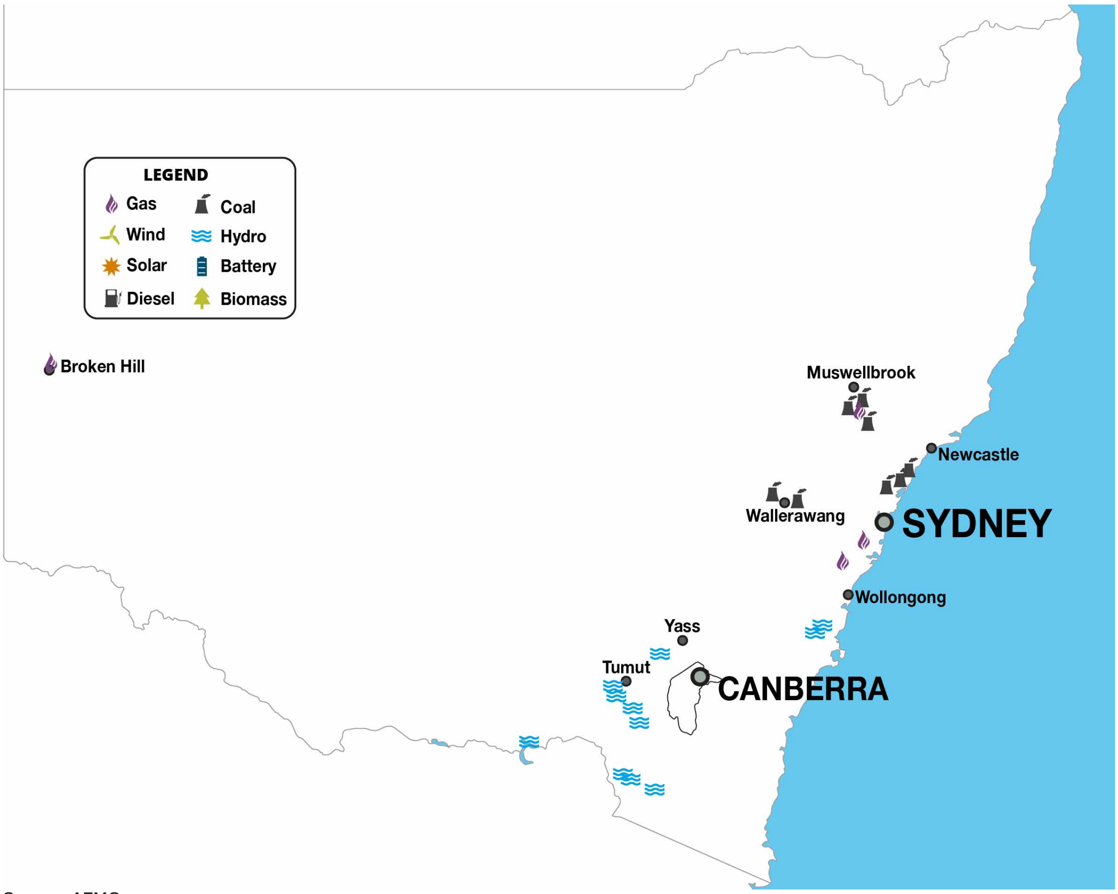
## Figure D.4: Location of generation in Queensland 2019




Source: AEMC

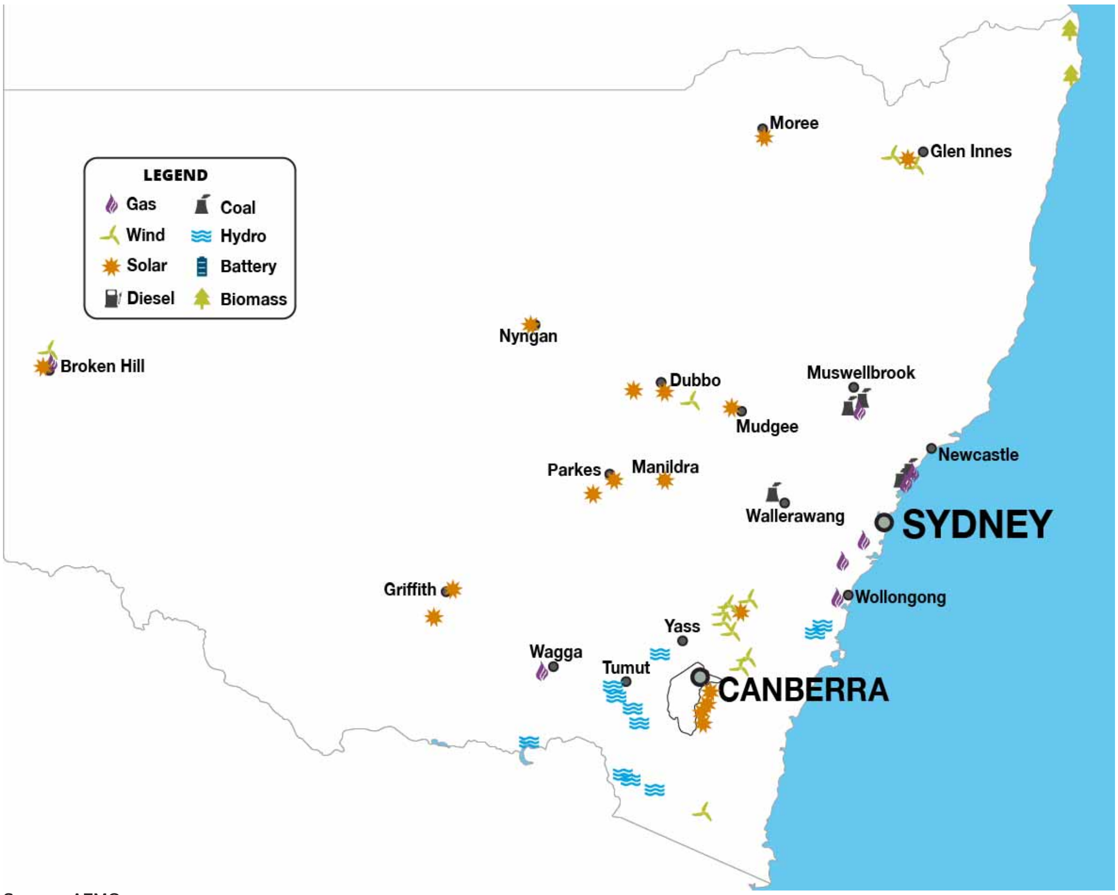
## D.3 New South Wales

### Figure D.5: Location of generation in New South Wales 2002




Source: AEMC

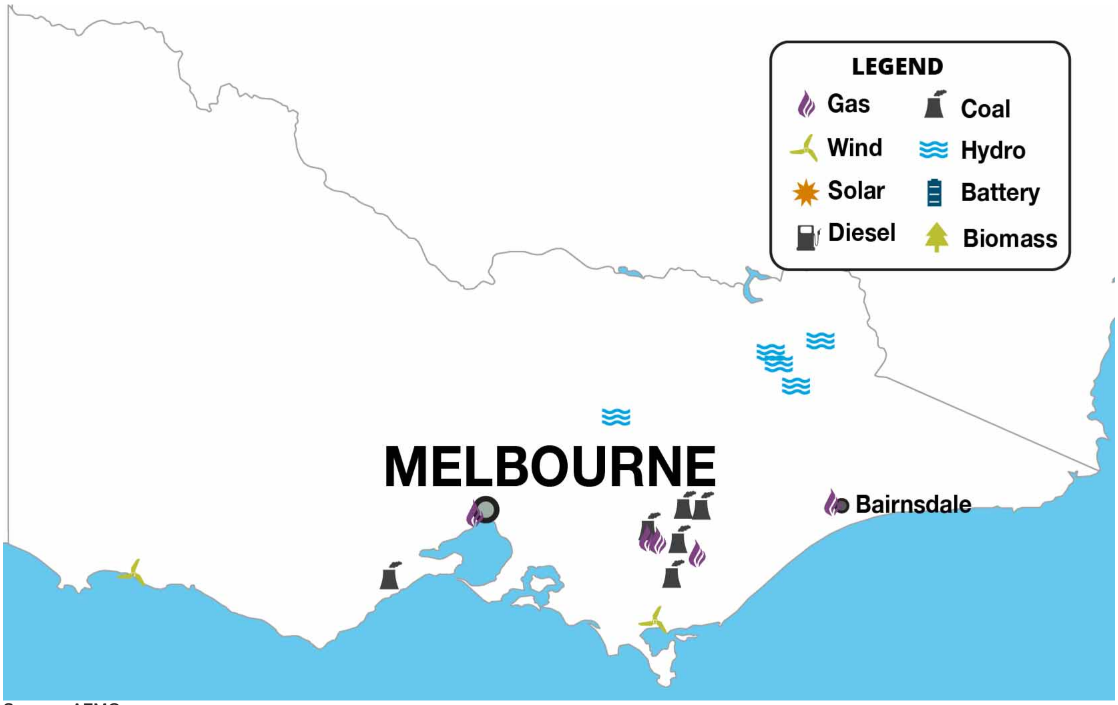
### Figure D.6: Location of generation in New South Wales 2019




Source: AEMC

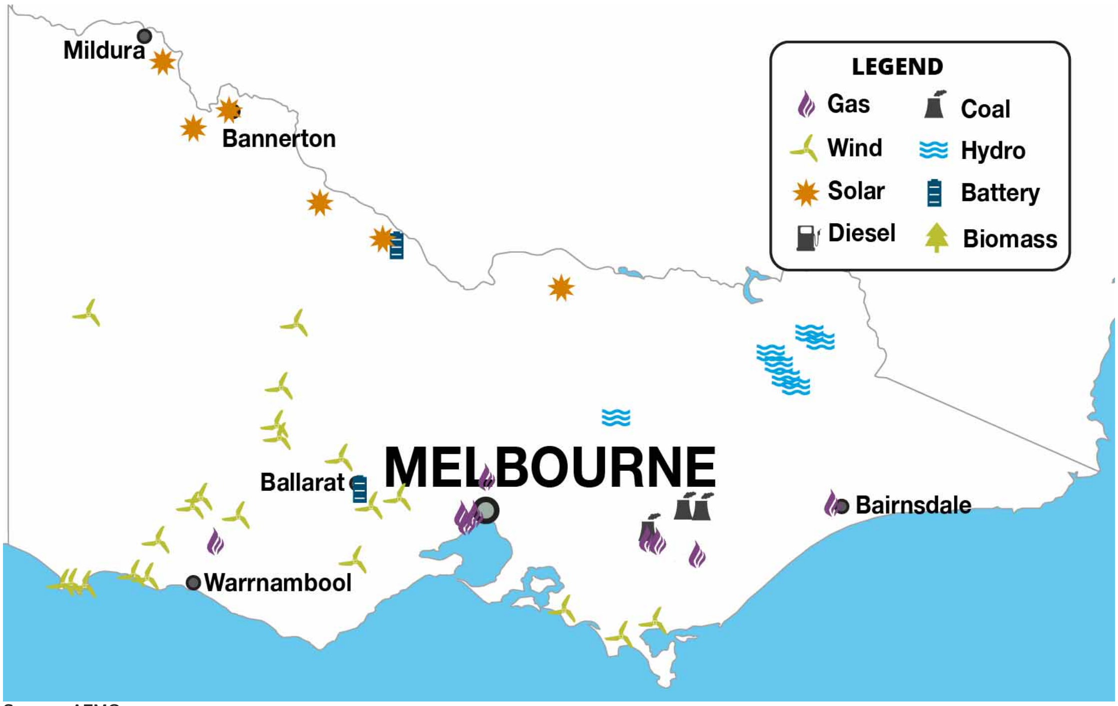
## D.4 Victoria

**Figure D.7: Location of generation in Victoria 2002**




Source: AEMC

**Figure D.8: Location of generation in Victoria 2019**



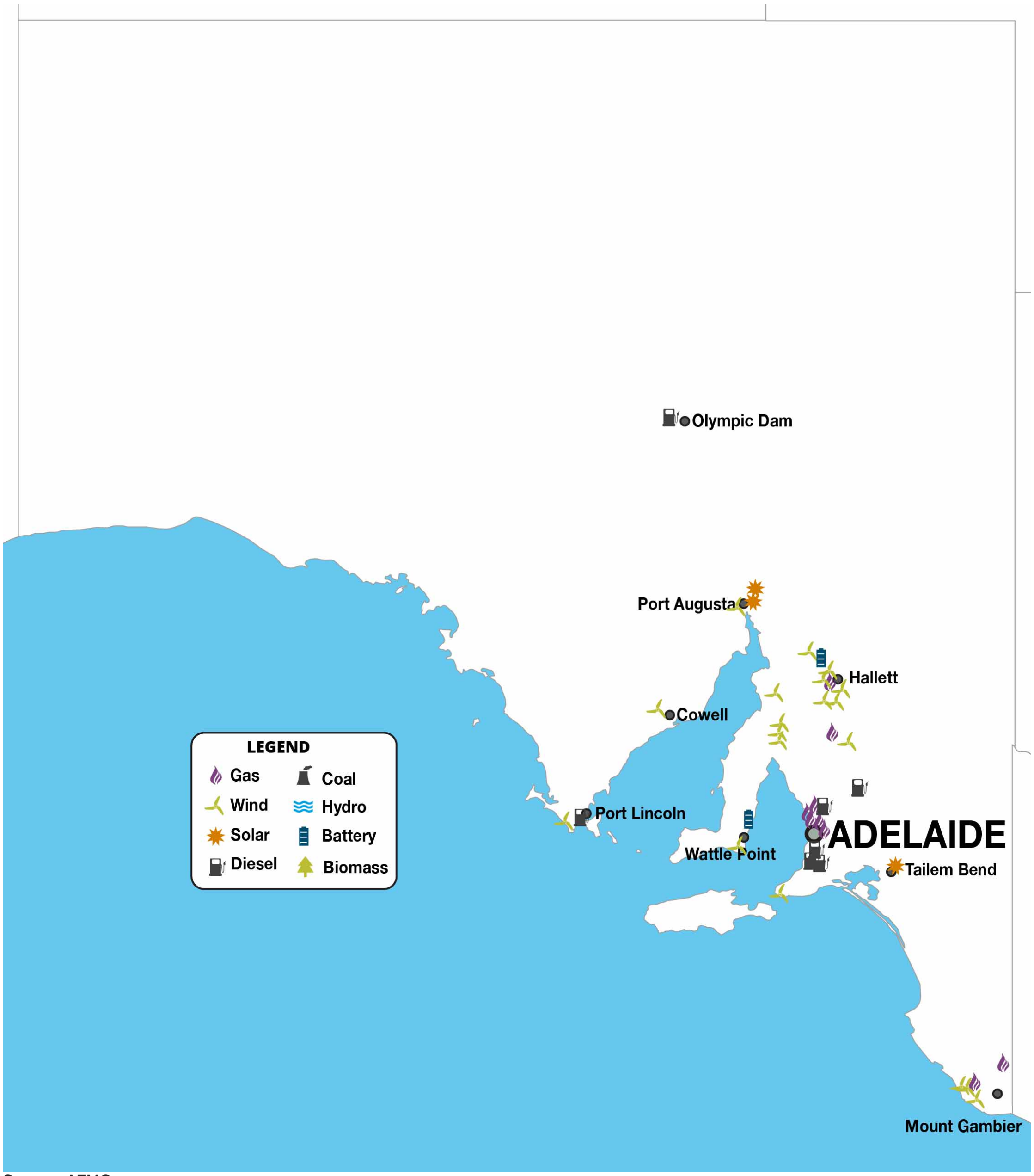

Source: AEMC

## D.5 South Australia

**Figure D.9: Location of generation in South Australia 2002**


Source: AEMC

## Figure D.10: Location of generation in South Australia 2019




Source: AEMC

# E QUANTITATIVE ANALYSIS UNDERTAKEN BY THE AEMC

The Commission has undertaken modelling to address the question raised by stakeholders of whether customer payments are higher or lower under ALFs. As we have described in section 5.6, the Commission's modelling of customer payments has focussed on generator receipts to account for the effect of the IRSR.

An additional output of the same modelling is the change in dispatch that arises from a shift to ALFs. This was also discussed in section 5.6.

The remainder of this section sets out:

- our principal assumptions;
  - the results of our analysis of the change in customer payments under ALFs; and
  - the results of our analysis of the change in dispatch under ALFs.

## E.1 Principal assumptions

Our modelling covers the same horizon as that of Baringa, ie, 1 July 2019 to 30 June 2020.[394] Where possible, we have made assumptions that use publicly available information, such as the Electricity Statement of Opportunities (ESOO) data sets.

Our principal assumptions for our base case are as follows:

- Demand values of 50 per cent POE from the August ESOO 2019;
- generator technical parameters from August ESOO 2019;
- marginal loss factors as per the August ESOO 2019;
- we have set average loss factors equal to the square root of the MLF; and
- bids based on profiles constructed from 2018-2019 historical bids.

We note that Baringa recognised the importance of maintaining the same bidding strategy across scenarios, stating that:[395]

> It is important to note that the impact of loss factors on wholesale electricity prices, above, assumes the bidding strategies and scarcity uplift seen under the current approach is maintained under different loss factor approaches. In reality, we expect some bidding behaviour may change, but we have not attempted to construct new potential bidding behaviours for the purposes of this report.

The Commission recognises the importance of this assumption and has kept bidding behaviour the same for both ALF and MLF scenarios.

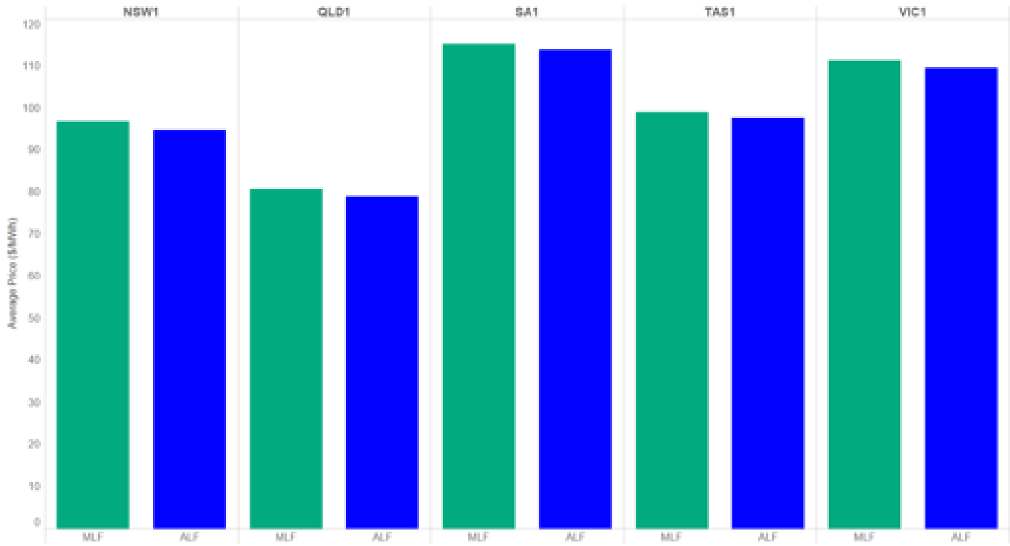
394 CEC supplementary submission to the consultation paper, Bargina report.

395 CEC supplementary submission to the consultation paper, Bargina report, p. 28

### E.1.1 Spot price results

The Commission has compared its spot price results to those obtained by Baringa. The Commission's modelling results yield spot prices that are generally about $10 per MWh higher than those of Baringa. This is likely to be due to different bid profiles used. As described in section 5.6, spot prices are predictably lower under ALFs than MLFs.

Figure E.1: Calculation of IRSR in a simple three-node power system

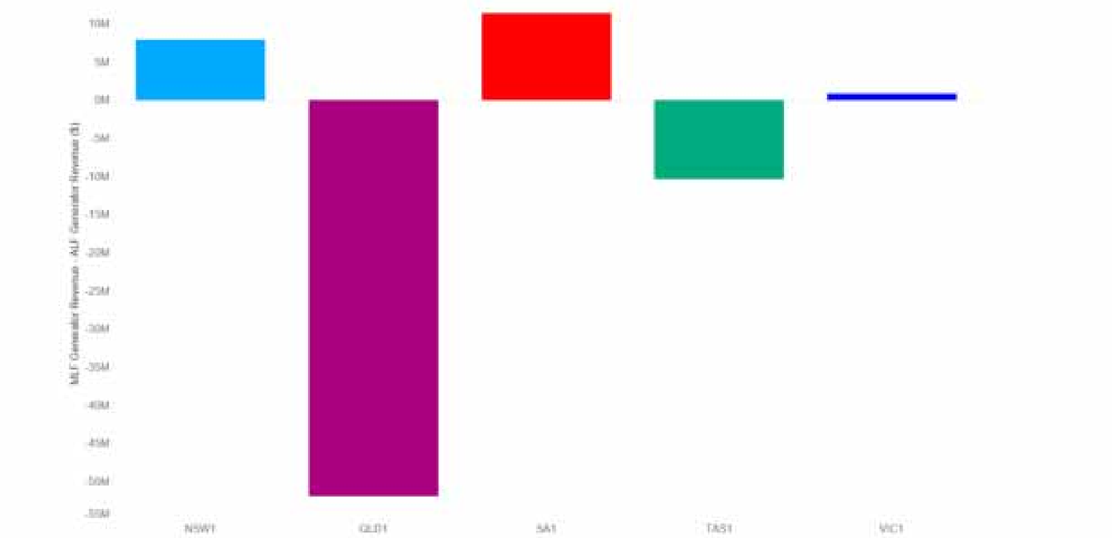



Source: AEMC

### E.1.2 Results – Change in customer payments arising from a shift to ALFs

Figure E.2 shows the modelled differential between customer payments under MLFs and ALFs by region. Negative values indicate that customer payments are lower under an MLFs framework. In aggregate, customer payments are $42 million higher under ALFs.

**Figure E.2: Change in customer payments (1 July 2019 to 30 June 2020)**




Source: AEMC
Note: Under an ALF framework, generator receipts would increase in New South Wales, South Australia and Victoria, but decrease in Queensland and Tasmania.

The Commission conducted sensitivity analysis to test the robustness of the modelling results to different assumptions. It has varied the following assumptions:

- **Reference years:** the Commission has considered 5 different reference years, namely 2014-15, 2015-16, 2016-17, 2017-18 and 2018-19. The reference year chosen affects the shape of demand, wind and solar output over the course of the year.
- **Level of demand:** the Commission has considered two different levels of demand, namely the 50 per cent and 10 per cent probability of exceedance levels.
- **Bidding behaviour of participants**: the Commission has considered two types of bidding behaviour:
  - bidding profiles based on 2018-19 bids; and
  - bidding at short-run marginal cost.

Table E.1 sets out the change in customer payments for each sensitivity analysis. Negative values indicate that customer payments are lower under MLFs. The results confirm that customer payments are not necessarily higher under ALFs or MLFs – it depends on the conditions of dispatch. However, in most cases that the Commission modelled, customer payments were lower under MLFs.

**Table E.1: Sensitivity analysis - difference in customer payments between MLFs and ALFs**

| BIDS | POE | 2014-15 ($M) | 2015-16 ($M) | 2016-17 ($M) | 2017-18 ($M) | 2018-19 ($M) |
|---|---|---|---|---|---|---|
| Historical | 10 | -56.4 | 169.9 | -31.1 | -61.2 | -65.0 |

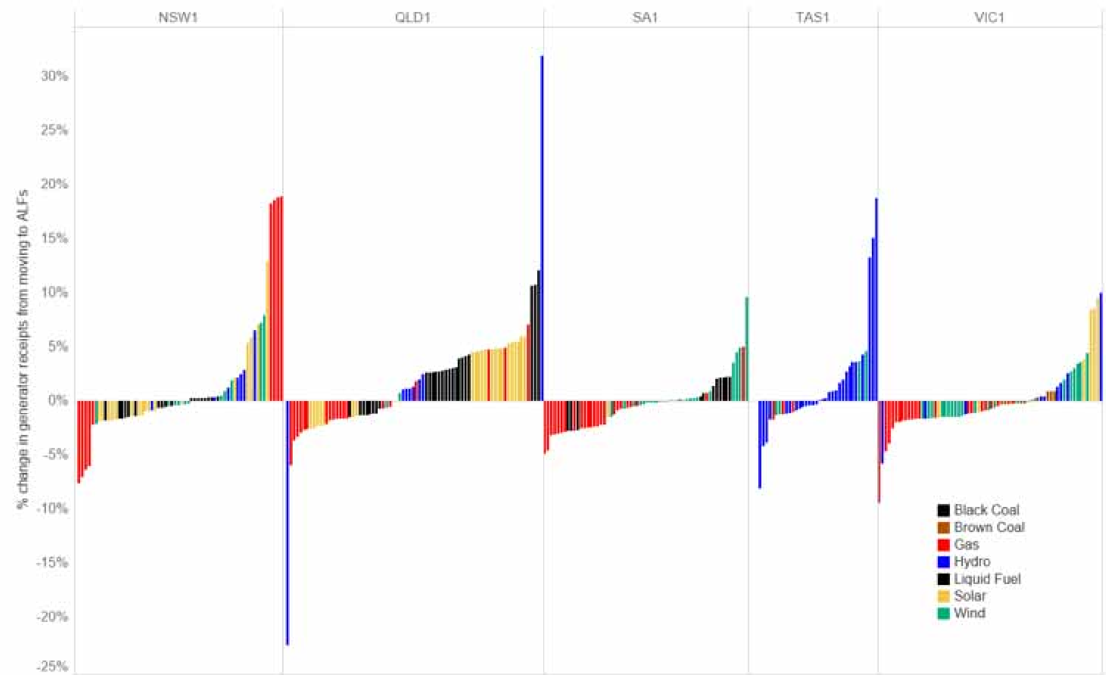
| BIDS | POE | 2014-15 ($M) | 2015-16 ($M) | 2016-17 ($M) | 2017-18 ($M) | 2018-19 ($M) |
|---|---|---|---|---|---|---|
| Historical | 50 | -44.9 | 140.5 | -48.1 | -71.4 | -41.9 |
| SRMC | 10 | -47.7 | -42.0 | -33.6 | -52.0 | -29.0 |
| SRMC | 50 | -32.4 | -17.2 | -40.0 | -30.4 | -36.6 |

Source: AEMC
Note: Where POE is the probability of exceedance and SRMC is the short-run marginal cost of generation.

### E.1.3 Results – Receipts for individual generators

As part of its modelling, the Commission has also considered the change in generator receipts by unit. Figure E.3 shows the percentage change in generator receipts by unit, coloured by fuel type. Given the large number of units in the NEM, not every bar is labelled on the horizontal axis. Bars above the line represent generators that see increased revenue from moving to ALFs; bars below the line represent generators that see decreased revenue from moving to ALFs.

**Figure E.3: Percentage change in generator receipts by unit (1 July 2019 to 30 June 2020)**




Source: AEMC, see appendix F for full data set.
Source: Please note that not all generators for each jurisdiction have been able to be named on the X axis due to formatting issues in the graph. However, all generators are represented in the body of the graph.

The Commission notes the following:

- The relative changes in revenues are substantial for some units.

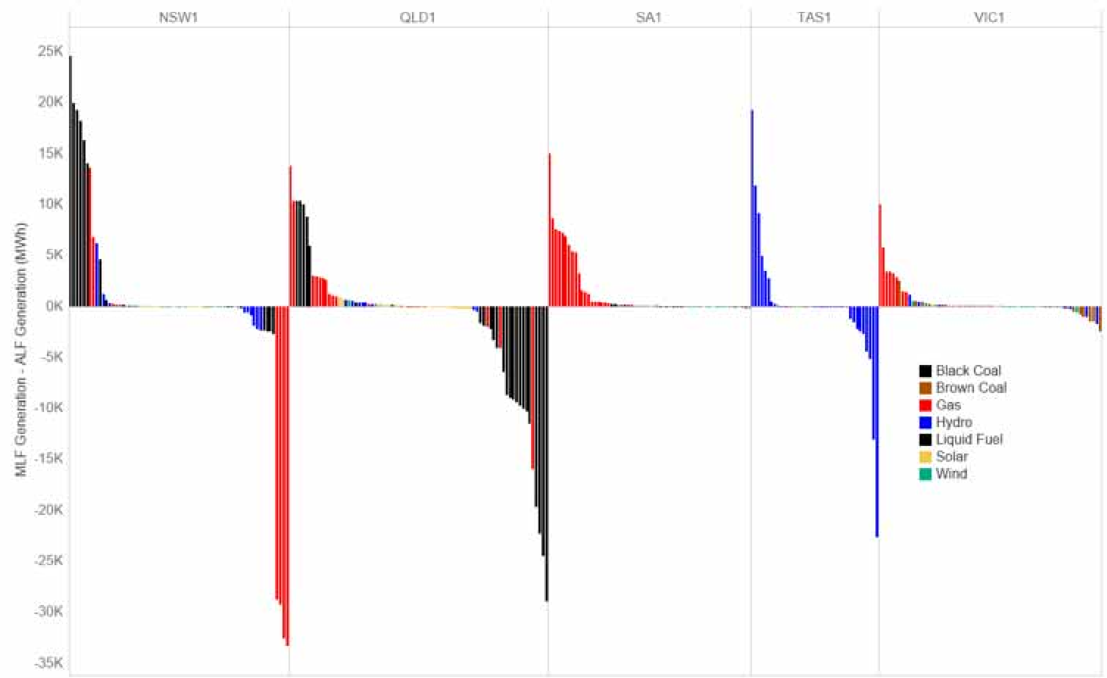
- Some committed renewable plants in the ESOO have MLFs of 1, whereas in reality these plants will have MLFs of less than 1. These plants will tend to move to the right in Figure E.1 when these lower MLFs are applied.
- As a class of generators, solar and wind farms tend to receive substantial percentage increases in revenue from moving to ALFs because they have lower loss factors.
- As a class of generators, gas fired generators tend to be worse off given that, with the notable exception to Uranquinty, because they are typically located close to the RRN.
- Outcomes for coal-fired generators are mixed but are not as pronounced as those for renewables or gas-fired generators.

### E.1.4 Results – Change in dispatch outcomes

Section 5.6 described that a change from MLFs to ALFs can affect the merit order, and so the set of generators that are dispatched.

Changes in the merit order manifest in changes in dispatch outcomes. The Commission has examined the changes in modelled dispatch volumes for each generator in the NEM. Figure E.4 shows the differential in dispatch volumes under ALFs versus MLFs for each unit in the NEM. Bars above the horizontal axis indicate units whose output is higher under MLFs; bars below the horizontal axis indicate units whose output is higher under ALFs.

**Figure E.4: Changes in the dispatch volume of generators (1 July 2019 to 30 June 2020)**




Source: AEMC, see appendix F for full data set.
Note: Bars above the horizontal axis indicate units whose output is higher under MLFs; bars below the horizontal axis indicate units whose output is higher under ALFs.

The Commission observes the following:

- The changes in dispatch volumes from moving to ALFs are typically small, with a maximum absolute change in output of 33.3 GWh for Uranquinty Unit 1 versus total modelled output of 216.6 GWh.
- Under ALFs, dispatch from South Australia falls in aggregate because of decreased output from Torrens A, Torrens B and Pelican Point which all sit at the regional reference node.
- Under ALFs, higher generation output is provided by Stanwell power station, which has an MLF of approximately 0.9.
- Under ALFs, there is higher output from Queensland overall.

The Commission has treated these results with caution because they are influenced by the assumed bidding profiles, and different bidding assumptions could affect the results. However, the direction of the changes that we observe in dispatch volumes is consistent with our expectations, ie, under ALFs:

- plants with relatively lower MLFs are dispatched more; and
- plants with relatively higher MLFs are dispatched less.

# F APPENDIX F

This appendix provides the data sets used in Chapter 5, figure 5.13 and within Appendix E figures E.3 and E.4.

## F.1 Change in generator revenue

Tables F.1 to F.5 contain the data sets for each NEM region used in Appendix E figure E.3.

**Table F.1: New South Wales percentage change in generator revenue**

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| STWF1 | 7.9% |
| WRWF1 | 7.2% |
| SAPHWF1 | 1.9% |
| BODWF1 | 0.8% |
| BOCORWF1 | 0.5% |
| GULLRWF1 | -0.2% |
| WOODLWN1 | -0.3% |
| CAPTL_WF | -0.4% |
| CULLRGWF | -0.4% |
| CROOKWF2 | -0.5% |
| TARALGA1 | -2.2% |
| BROKENH1 | 12.8% |
| WRSF1 | 7.1% |
| MOREESF1 | 5.9% |
| COLEASF1 | 5.3% |
| BERYLSF1 | 2.1% |
| GULLRSF1 | -0.4% |
| PARSF1 | -0.9% |
| MANSLR1 | -1.0% |
| NYNGAN1 | -1.0% |
| Bomen Solar Farm | -1.4% |
| Limondale SF1 | -1.4% |
| Molong SF | -1.5% |
| Darlington Point SF | -1.8% |
| Nevertire Solar Farm | -1.8% |
| Sunraysia Solar Farm | -1.9% |
| Finley SF | -1.9% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| Limondale SF2 | -1.9% |
| HVGTS1 | -0.5% |
| HVGTS2 | -0.6% |
| TUMUT3 | 6.5% |
| GUTHEGA1 | 2.8% |
| GUTHEGA2 | 2.5% |
| TUMUT1 | 2.1% |
| TUMUT2 | 1.2% |
| BLOWERNG | 0.3% |
| HUMENSW | -0.9% |
| URANQ11 | 18.8% |
| URANQ13 | 18.8% |
| URANQ14 | 18.5% |
| URANQ12 | 18.2% |
| TALWA1 | -2.3% |
| CG1 | -6.0% |
| CG4 | -6.3% |
| CG3 | -7.1% |
| CG2 | -7.6% |
| SITHE | 0.0% |
| LD01 | 0.3% |
| BW01 | 0.3% |
| BW04 | 0.3% |
| BW02 | 0.3% |
| BW03 | 0.3% |
| LD03 | 0.3% |
| LD02 | 0.2% |
| LD04 | 0.2% |
| MP2 | -0.5% |
| MP1 | -0.7% |
| ER02 | -1.5% |
| ER01 | -1.5% |
| VP6 | -1.6% |
| ER04 | -1.7% |
| VP5 | -1.7% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| South | -1.9% |

Source: AEMC
Note: AEMC modelling results.

**Table F.2: Queensland percentage change in generator revenue**

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| MEWF1 | 0.7% |
| Coopers Gap Wind Farm | -0.6% |
| HAYMSF1 | 6.0% |
| DAYDSF1 | 6.0% |
| HAMISF1 | 5.5% |
| WHITSF1 | 5.5% |
| CSPVPS1 | 5.4% |
| CLARESF1 | 5.3% |
| KSP1 | 4.8% |
| RRSF1 | 4.8% |
| HUGSF1 | 4.8% |
| Lilyvale Solar Farm | 4.8% |
| Haughton Solar Farm | 4.7% |
| Rugby Run Solar Farm | 4.7% |
| EMERASF1 | 4.6% |
| LRSF1 | 4.5% |
| CLERMSF1 | 4.5% |
| CHILDSF1 | 0.0% |
| SRSF1 | 0.0% |
| Oakey SF | -1.5% |
| DDSF1 | -1.5% |
| Maryrorough SF | -2.3% |
| Yarranlea Solar Farm | -2.3% |
| Oakey 2 Solar Farm | --2.3% |
| SMCSF1 | -2.5% |
| Warwick Solar Farm | -2.6% |
| MSTUART3 | 12.0% |
| MSTUART2 | 10.7% |
| MSTUART1 | 10.6% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| MACKAYGT | 0.0% |
| W/HOE#1 | 31.8% |
| BARRON-2 | 2.5% |
| BARRON-1 | 2.0% |
| KAREEYA1 | 1.2% |
| KAREEYA4 | 1.1% |
| KAREEYA2 | 1.1% |
| KAREEYA3 | 1.0% |
| W/HOE#2 | -22.6% |
| YABULU | 7.0% |
| BARCALDN | 4.9% |
| YABULU2 | 4.7% |
| YARWUN_1 | 1.8% |
| OAKEY1 | -0.6% |
| OAKEY2 | -0.7% |
| BRAEMAR5 | -1.6% |
| CPSA_GT2 | -1.7% |
| CPSA_GT1 | -1.7% |
| CPSA_ST | -1.7% |
| BRAEMAR6 | -1.7% |
| BRAEMAR7 | -1.8% |
| BRAEMAR2 | -2.2% |
| ROMA_8 | -2.7% |
| ROMA_7 | -2.7% |
| SWAN_E | -2.9% |
| BRAEMAR3 | -3.4% |
| BRAEMAR1 | -3.7% |
| DDPS1 | -6.0% |
| STAN-4 | 4.3% |
| STAN-2 | 4.1% |
| STAN-3 | 3.9% |
| STAN-1 | 3.8% |
| CPP_4 | 3.0% |
| CPP_3 | 3.0% |
| CALL_B_1 | 2.9% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| CALL_B_2 | 2.9% |
| GSTONE4 | 2.7% |
| GSTONE5 | 2.7% |
| GSTONE3 | 2.7% |
| GSTONE2 | 2.6% |
| GSTONE6 | 2.6% |
| GSTONE1 | 2.6% |
| KPP_1 | -0.8% |
| MPP_2 | -1.2% |
| MPP_1 | -1.2% |
| TNPS1 | -1.2% |
| TARONG#2 | -1.3% |
| TARONG#4 | -1.4% |
| TARONG#1 | -1.4% |
| TARONG#3 | -1.5% |

Source: AEMC
Note: AEMC modelling results.

Table F.3: **South Australia percentage change in generator revenue**

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| WPWF | 9.6% |
| CATHROCK | 4.9% |
| MTMILLAR | 4.5% |
| SNOWTWN1 | 3.5% |
| CLEMGPWF | 0.8% |
| WATERLWF | 0.3% |
| HDWF2 | 0.2% |
| HDWF1 | 0.2% |
| HDWF3 | 0.2% |
| SNOWSTH1 | 0.1% |
| SNOWNTH1 | 0.1% |
| NBHWF1 | 0.0% |
| BLUFF1 | 0.0% |
| HALLWF1 | -0.1% |
| LKBONNY3 | -0.2% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| HALLWF2 | -0.2% |
| LKBONNY2 | -0.2% |
| LKBONNY1 | -0.2% |
| Lincoln Gap WF - stage 2 | -0.3% |
| LGAPWF1 | -0.4% |
| Willogoleche WF | -0.5% |
| CNUNDAWF | -0.7% |
| STARHLWF | -1.5% |
| BNGSF1 | 0.1% |
| Bungala Two Solar Farm | 0.1% |
| TBSF1 | -1.5% |
| SNUG3 | 2.2% |
| SNUG2 | 2.2% |
| ANGAS1 | 2.1% |
| SNUG1 | 2.1% |
| ANGAS2 | 2.1% |
| POR01-2 | 1.3% |
| POR01-1 | 0.7% |
| POR01-3 | 0.4% |
| Lonsdale | 0.4% |
| PTSTAN1_2 | -2.8% |
| PTSTAN1_1 | -2.8% |
| AGLHAL | 5.0% |
| MINTARO | 0.7% |
| QPS2 | -0.1% |
| QPS4 | -0.5% |
| QPS3 | -0.5% |
| LADBROK1 | -0.7% |
| QPS5 | -0.8% |
| QPS1 | -0.9% |
| LADBROK2 | -1.3% |
| TORRB1 | -2.2% |
| PPCCGTGT1 | -2.3% |
| TORRA1 | -2.4% |
| TORRB4 | -2.4% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
| --- | --- |
| TORRA3 | -2.5% |
| TORRB3 | -2.5% |
| TORRA4 | -2.5% |
| TORRB2 | -2.5% |
| TORRA2 | -2.8% |
| DRYCGT2 | -2.9% |
| DRYCGT1 | -2.9% |
| DRYCGT3 | -3.0% |
| OsborneGT | -3.1% |
| OsborneST | -3.2% |
| PPCCGT | -4.6% |
| BIPS | -4.9% |

Source: AEMC
Note: AEMC modelling results.

Table F.4: **Tasmania percentage change in generator revenue**

| GENERATOR | CHANGE IN GENERATOR REVENUE |
| --- | --- |
| WOOLNTH1 | 4.6% |
| MUSSELR1 | 3.6% |
| Cattle Hill Wind Farm | -1.3% |
| Granville Harbour Wind Farm | -1.4% |
| TU111-1-5 | 18.7% |
| TR111-1-4 | 15.1% |
| TA111-1-6 | 13.2% |
| BASTYAN | 4.3% |
| TRIBUTE | 3.6% |
| REECE2 | 3.5% |
| CA111-1 | 3.1% |
| LK_ECHO | 2.6% |
| JBUTTERS | 2.0% |
| FISHER | 1.7% |
| GO181-1 | 0.9% |
| GO183-3 | 0.9% |
| GO182-2 | 0.8% |
| PO162-2 | 0.2% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| MACKNTSH | 0.1% |
| PO161-1 | 0.1% |
| REECE1 | -0.4% |
| PO163-3 | -0.4% |
| PO164-4 | -0.4% |
| PO165-5 | -0.5% |
| PO166-6 | -0.6% |
| LM111-1 | -0.7% |
| WY111-1 to 3 | -0.8% |
| CA112-2 | -1.1% |
| LI111-3 | -1.2% |
| WI111-1 | -1.8% |
| MEADOWBK | -3.9% |
| DEVILS_G | -4.2% |
| CETHANA | -8.1% |
| BBTHREE2 | -1.1% |
| TVPP104 | -1.3% |
| BBTHREE3 | -1.8% |
| TVCC201_ST | 0.0% |
| TVCC201_GT | 0.0% |
| BBTHREE1 | 0.0% |

Source: AEMC
Note: AEMC modelling results.

**Table F.5: Victoria percentage change in generator revenue**

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| MUWAWF1 | 4.45% |
| ARWF1 | 3.55% |
| KIATAWF1 | 3.39% |
| Crowlands WF | 3.03% |
| CHALLHWF | 2.69% |
| WAUBRAWF | 1.94% |
| MERCER01 | 0.18% |
| YSWF1 | -0.12% |
| SALTCRK1 | -0.27% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| MACARTH1 | -0.66% |
| MTGELWF1 | -0.87% |
| BALDHWF1 | -1.09% |
| Cherry Tree Wind Farm | -1.46% |
| Bulgana Green Power Hub - Wind Farm | -1.49% |
| Lal Lal WF Yendon | -1.50% |
| Stockyard Hill WF | -1.51% |
| Lal Lal WF Elaine | -1.51% |
| Moorabool Wind Farm | -1.54% |
| PORTWF | -1.55% |
| YAMBUKWF | -1.64% |
| OAKLAND1 | -1.65% |
| MLWF1 | -1.67% |
| KARSF1 | 9.49% |
| WEMENSF1 | 8.44% |
| BANN1 | 8.41% |
| GANNSF1 | 3.81% |
| Numurkah Solar Farm | -1.06% |
| Yatpool Solar Farm | -1.06% |
| MURRAY | 9.96% |
| MCKAY | 2.53% |
| HUMEV | 1.64% |
| DARTM1 | 1.29% |
| BOGONG1 | 0.42% |
| BOGONG2 | 0.41% |
| EILDON2 | -1.29% |
| EILDON1 | -1.66% |
| WKIEWA1 and 2 | -5.83% |
| JLA04 | 0.08% |
| JLB03 | -0.28% |
| JLB02 | -0.48% |
| JLA01 | -0.71% |
| JLA02 | -0.91% |
| JLB01 | -1.01% |
| VPGS4 | -1.14% |

| GENERATOR | CHANGE IN GENERATOR REVENUE |
|---|---|
| JLA03 | -1.17% |
| BDL01 | -1.63% |
| VPGS2 | -1.71% |
| VPGS1 | -1.71% |
| BDL02 | -1.75% |
| VPGS3 | -1.76% |
| MORTLK12 | -1.84% |
| VPGS5 | -1.88% |
| NPS | -2.01% |
| MORTLK11 | -2.02% |
| VPGS6 | -2.58% |
| LNGS1 | -3.95% |
| LNGS2 | -4.70% |
| AGLSOM | -9.47% |
| YWPS2 | 0.88% |
| YWPS4 | 0.88% |
| YWPS3 | 0.83% |
| YWPS1 | 0.29% |
| LOYYB2 | -0.25% |
| LOYYB1 | -0.25% |
| LYA4 | -0.27% |
| LYA1 | -0.31% |
| LYA3 | -0.33% |
| LYA2 | -0.34% |

Source: AEMC
Note: AEMC modelling results.

## F.2 Change in the dispatch volume of generators

Tables F.1 to F.5 contains the data sets for each NEM region used in both Chapter 5 figure 5.13 and Appendix E figure E.4.

**Table F.6: New South Wales change in dispatch volume (MWh)**

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| CAPTL_WF | -28.30 |
| CULLRGWF | -13.63 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| TARALGA1 | 0.00 |
| STWF1 | 0.00 |
| SAPHWF1 | 0.00 |
| GULLRWF1 | 0.00 |
| CROOKWF2 | 0.00 |
| BODWF1 | 0.00 |
| BOCORWF1 | 0.00 |
| WOODLWN1 | 0.96 |
| WRWF1 | 72.14 |
| BERYLSF1 | -34.10 |
| Sunraysia Solar Farm | 0.00 |
| NYNGAN1 | 0.00 |
| Nevertire Solar Farm | 0.00 |
| MOREESF1 | 0.00 |
| Molong SF | 0.00 |
| Limondale SF1 | 0.00 |
| Finley SF | 0.00 |
| COLEASF1 | 0.00 |
| Bomen Solar Farm | 0.00 |
| Darlington Point SF | 3.57 |
| BROKENH1 | 5.12 |
| GULLRSF1 | 6.69 |
| WRSF1 | 10.38 |
| PARSF1 | 11.07 |
| Limondale SF2 | 14.20 |
| MANSLR1 | 16.06 |
| HVGTS1 | -33.73 |
| HVGTS2 | -31.41 |
| TUMUT1 | -2,380.52 |
| SHGEN03 | -2,255.37 |
| SHGEN04 | -1,912.10 |
| TUMUT2 | -872.90 |
| SHGEN01 | -633.60 |
| SHGEN02 | -620.77 |
| GUTHEGA1 | -37.20 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| GUTHEGA2 | -37.20 |
| HUMENSW | 280.16 |
| BLOWERNG | 1,236.61 |
| TUMUT3 | 6,222.37 |
| URANQ11 | -33,320.62 |
| URANQ12 | -32,612.35 |
| URANQ14 | -29,271.30 |
| URANQ13 | -28,774.36 |
| SITHE | 0.00 |
| CG1 | 137.49 |
| CG3 | 163.31 |
| CG2 | 179.13 |
| CG4 | 6,835.34 |
| TALWA1 | 13,588.22 |
| BW01 | -2,517.19 |
| BW03 | -2,517.19 |
| BW04 | -2,465.88 |
| BW02 | -2,391.96 |
| LD02 | -204.73 |
| LD03 | 27.80 |
| LD01 | 71.50 |
| LD04 | 118.24 |
| MP2 | 641.50 |
| MP1 | 4,605.34 |
| ER02 | 14,024.66 |
| ER01 | 16,367.73 |
| ER04 | 18,162.88 |
| VP6 | 19,266.83 |
| VP5 | 19,987.28 |
| ER03 | 24,567.74 |

Source: AEMC
Note: AEMC modelling results.

Table F.7: Queensland change in dispatch volume (MWh)

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| MEWF1 | 214.93 |
| Coopers Gap Wind Farm | 606.72 |
| HAYMSF1 | -31.14 |
| DAYDSF1 | -24.91 |
| HAMISF1 | -275.26 |
| WHITSF1 | -148.25 |
| CSPVPS1 | -214.74 |
| CLARESF1 | 0.00 |
| KSP1 | -310.22 |
| RRSF1 | 179.93 |
| HUGSF1 | -149.35 |
| Lilyvale Solar Farm | 193.89 |
| Haughton Solar Farm | 917.39 |
| Rugby Run Solar Farm | 161.42 |
| EMERASF1 | -91.24 |
| LRSF1 | -10.32 |
| CLERMSF1 | 102.15 |
| CHILDSF1 | 89.34 |
| SRSF1 | -179.81 |
| Oakey SF | -171.72 |
| DDSF1 | 144.05 |
| Maryrorough SF | -298.87 |
| Yarranlea Solar Farm | -312.70 |
| Oakey 2 Solar Farm | -124.75 |
| SMCSF1 | 685.93 |
| Warwick Solar Farm | -108.87 |
| MSTUART3 | -6,481.70 |
| MSTUART2 | -11,485.43 |
| MSTUART1 | -10,355.18 |
| MACKAYGT | 0.00 |
| W/HOE#1 | -520.79 |
| BARRON-2 | -359.64 |
| BARRON-1 | 380.44 |
| KAREEYA1 | 241.29 |
| KAREEYA4 | 402.74 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| KAREEYA2 | 569.86 |
| KAREEYA3 | 615.29 |
| W/HOE#2 | 388.83 |
| YABULU | -15,932.10 |
| BARCALDN | -1,961.99 |
| YABULU2 | -4,072.92 |
| YARWUN_1 | 0.00 |
| OAKEY1 | 78.71 |
| OAKEY2 | 242.49 |
| BRAEMAR5 | 2,587.09 |
| CPSA_GT2 | -11.64 |
| CPSA_GT1 | -10.10 |
| CPSA_ST | -5.96 |
| BRAEMAR6 | 2,792.39 |
| BRAEMAR7 | 3,025.71 |
| BRAEMAR2 | 1,260.47 |
| ROMA_8 | 1,076.51 |
| ROMA_7 | 976.49 |
| SWAN_E | 13,764.20 |
| BRAEMAR3 | 2,892.99 |
| BRAEMAR1 | 2,826.34 |
| DDPS1 | 10,340.86 |
| STAN-4 | -28,975.98 |
| STAN-2 | -24,479.08 |
| STAN-3 | -22,337.56 |
| STAN-1 | -19,703.46 |
| CPP_4 | -4,070.04 |
| CPP_3 | -1,872.55 |
| CALL_B_1 | -3,323.50 |
| CALL_B_2 | -2,253.55 |
| GSTONE4 | -9,728.07 |
| GSTONE5 | -10,072.96 |
| GSTONE3 | -8,756.49 |
| GSTONE2 | -8,959.28 |
| GSTONE6 | -9,150.63 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| GSTONE1 | -9,374.71 |
| KPP_1 | -1,603.03 |
| MPP_2 | 122.21 |
| MPP_1 | 421.68 |
| TNPS1 | 5,929.07 |
| TARONG#2 | 8,790.44 |
| TARONG#4 | 10,298.93 |
| TARONG#1 | 9,985.07 |
| TARONG#3 | 10,337.08 |

Source: AEMC
Note: AEMC modelling results.

Table F.8: South Australia change in dispatch volume (MWh)

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| WPWF | -234.06 |
| CATHROCK | -27.89 |
| MTMILLAR | -16.80 |
| SNOWTWN1 | -2.12 |
| CLEMGPWF | -24.71 |
| WATERLWF | 4.39 |
| HDWF2 | 177.25 |
| HDWF1 | 73.49 |
| HDWF3 | -1.91 |
| SNOWSTH1 | -17.05 |
| SNOWNTH1 | -47.51 |
| NBHWF1 | 0.00 |
| BLUFF1 | 0.00 |
| HALLWF1 | 0.00 |
| LKBONNY3 | 2.81 |
| HALLWF2 | 0.00 |
| LKBONNY2 | 0.00 |
| LKBONNY1 | 53.27 |
| Lincoln Gap WF - stage 2 | -10.62 |
| LGAPWF1 | -26.16 |
| Willogoleche WF | 60.42 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| CNUNDAWF | 31.18 |
| STARHLWF | 22.45 |
| BNGSF1 | -4.20 |
| Bungala Two Solar Farm | 25.95 |
| TBSF1 | -0.81 |
| SNUG3 | 0.88 |
| SNUG2 | 1.42 |
| ANGAS1 | -49.15 |
| SNUG1 | 3.96 |
| ANGAS2 | -34.54 |
| POR01-2 | 0.65 |
| POR01-1 | 6.79 |
| POR01-3 | 13.59 |
| Lonsdale | 147.19 |
| PTSTAN1_2 | 219.65 |
| PTSTAN1_1 | 227.79 |
| AGLHAL | 66.51 |
| MINTARO | -215.04 |
| QPS2 | 122.21 |
| QPS4 | 143.03 |
| QPS3 | 174.46 |
| LADBROK1 | 438.99 |
| QPS5 | 1,554.02 |
| QPS1 | 314.61 |
| LADBROK2 | 505.03 |
| TORRB1 | 6,866.49 |
| PPCCGTGT1 | 7,241.49 |
| TORRA1 | 5,371.30 |
| TORRB4 | 7,565.01 |
| TORRA3 | 5,308.89 |
| TORRB3 | 8,624.18 |
| TORRA4 | 1,422.96 |
| TORRB2 | 7,402.47 |
| TORRA2 | 1,267.29 |
| DRYCGT2 | 403.98 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| DRYCGT1 | 421.58 |
| DRYCGT3 | 438.24 |
| OsborneGT | 6,079.32 |
| OsborneST | 3,288.06 |
| PPCCGT | 14,977.67 |
| BIPS | 0.00 |

Source: AEMC
Note: AEMC modelling results.

Table F.9: **Tasmania change in dispatch volume (MWh)**

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| WOOLNTH1 | 0.00 |
| MUSSELR1 | 0.00 |
| Cattle Hill Wind Farm | 0.00 |
| Granville Harbour Wind Farm | 0.00 |
| TU111-1-5 | 37.43 |
| TR111-1-4 | -22,656.56 |
| TA111-1-6 | -1,212.97 |
| BASTYAN | -13,091.61 |
| TRIBUTE | -4,416.20 |
| REECE2 | -5,167.75 |
| CA111-1 | -1,570.07 |
| LK_ECHO | 0.00 |
| JBUTTERS | 0.00 |
| FISHER | -2,442.73 |
| GO181-1 | 0.00 |
| GO183-3 | 0.00 |
| GO182-2 | 0.00 |
| PO162-2 | 0.00 |
| MACKNTSH | 3,471.84 |
| PO161-1 | 0.00 |
| REECE1 | 11,878.63 |
| PO163-3 | 0.00 |
| PO164-4 | 0.00 |
| PO165-5 | 0.00 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| PO166-6 | 0.00 |
| LM111-1 | 2,721.09 |
| WY111-1 to 3 | -2,198.59 |
| CA112-2 | 261.04 |
| LI111-3 | -2,735.54 |
| WI111-1 | 2,721.09 |
| MEADOWBK | 4,923.24 |
| DEVILS_G | 9,127.87 |
| CETHANA | 19,316.92 |
| BBTHREE2 | -12.31 |
| TVPP104 | -61.15 |
| BBTHREE3 | 0.00 |
| TVCC201_ST | 0.00 |
| TVCC201_GT | 0.00 |
| BBTHREE1 | 0.00 |

Source: AEMC
Note: AEMC modelling results.

Table F.10: Victoria change in dispatch volume (MWh)

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| ARWF1 | -618.40 |
| MUWAWF1 | -153.01 |
| MTGELWF1 | -145.94 |
| Lal Lal WF Elaine | -116.99 |
| Lal Lal WF Yendon | -107.03 |
| Stockyard Hill WF | -80.71 |
| WAUBRAWF | -74.03 |
| CHALLHWF | -63.93 |
| KIATAWF1 | -37.57 |
| Bulgana Green Power Hub - Wind Farm | -26.91 |
| YSWF1 | -1.95 |
| PORTWF | 0.00 |
| Cherry Tree Wind Farm | 0.00 |
| MLWF1 | 0.19 |
| YAMBUKWF | 13.59 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| OAKLAND1 | 41.82 |
| Crowlands WF | 45.69 |
| SALTCRK1 | 59.17 |
| MACARTH1 | 92.63 |
| BALDHWF1 | 153.27 |
| MERCER01 | 272.18 |
| Moorabool Wind Farm | 578.02 |
| GANNSF1 | -91.80 |
| Yatpool Solar Farm | -21.59 |
| WEMENSF1 | 22.25 |
| BANN1 | 25.85 |
| KARSF1 | 77.38 |
| Numurkah Solar Farm | 168.72 |
| DARTM1 | -1,681.99 |
| MURRAY | -1,055.55 |
| HUMEV | -283.60 |
| MCKAY | -209.02 |
| WKIEWA1 and 2 | -128.76 |
| BOGONG2 | 99.40 |
| BOGONG1 | 144.76 |
| EILDON2 | 506.56 |
| EILDON1 | 1,115.68 |
| JLB03 | -231.48 |
| JLB02 | -148.06 |
| JLA04 | -111.79 |
| JLA01 | 40.32 |
| VPGS2 | 52.23 |
| VPGS3 | 52.90 |
| VPGS1 | 57.76 |
| VPGS4 | 60.21 |
| VPGS5 | 62.40 |
| VPGS6 | 65.72 |
| JLA02 | 67.64 |
| JLB01 | 88.38 |
| JLA03 | 94.12 |

| GENERATOR | CHANGE IN DISPATCH VOLUME |
|---|---|
| BDL01 | 1,435.95 |
| BDL02 | 1,467.95 |
| MORTLK12 | 2,865.90 |
| LNGS2 | 3,229.26 |
| LNGS1 | 3,430.75 |
| AGLSOM | 3,464.57 |
| MORTLK11 | 5,808.24 |
| NPS | 10,040.86 |
| YWPS4 | -2,458.69 |
| YWPS2 | -1,506.05 |
| YWPS1 | -1,485.40 |
| LOYYB2 | -1,011.15 |
| YWPS3 | -832.85 |
| LOYYB1 | -518.39 |
| LYA2 | 205.75 |
| LYA4 | 467.70 |
| LYA1 | 572.80 |
| LYA3 | 2,534.13 |

Source: AEMC
Note: AEMC modelling results.