Draft determination on network control service costs in the Eastern Goldfields

Submitted by Western Power

4 March 2021

Economic Regulation Authority
WESTERN AUSTRALIA

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Invitation to make submissions

Submissions are due by 4:00 pm WST, Friday, 26 March 2021.

The ERA invites comment on this draft determination and encourages all interested parties to provide comment on the matters discussed and any other issues or concerns not already raised in this draft determination.

We would prefer to receive your comments via our online submission form https://www.erawa.com.au/consultation

You can also send comments through:

Email: publicsubmissions@erawa.com.au
Post: PO Box 8469, PERTH BC WA 6849

Please note that submissions provided electronically do not need to be provided separately in hard copy.

All submissions will be made available on our website unless arrangements are made in advance between the author and the ERA. This is because it is preferable that all submissions be publicly available to facilitate an informed and transparent consultative process. Parties wishing to submit confidential information are requested to contact us at info@erawa.com.au.

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1. Draft determination

On 21 October 2020, Western Power applied to the Economic Regulation Authority for a determination on network control service costs in the Eastern Goldfields. Western Power sought approval for non-capital costs of $12.3 million (nominal $) for the period 1 October 2018 to 30 June 2022. The application includes actual and forecast costs.

The costs Western Power is seeking are for a contract with Synergy to provide back-up electricity from its West Kalgoorlie generators when there is a planned or unplanned outage on the 220 kV transmission line supplying the Eastern Goldfields. The contract ensures that essential services loads and most small use customers in the Eastern Goldfields continue to receive an electricity supply when there is an outage on the 220 kV transmission line.

Western Power submitted its application under section 6.76 of the *Electricity Networks Access Code 2004.* It claimed confidentiality over most of the information provided. The ERA required further information and explanations from Western Power to enable it to assess the application.

The ERA has worked with Western Power to ensure that sufficient information is published to enable stakeholder consultation and a transparent decision-making process.[1]

The ERA must determine whether the costs meet the requirements of section 6.40 of the Access Code to include only those non-capital costs that would be incurred by a service provider efficiently minimising costs. The ERA's draft determination is that $9.8 million of Western Power's proposal meets this requirement.

This amount includes:

- actual and forecast fixed contract costs for the period 1 October 2018 to 30 June 2022
- actual variable contract costs that have been incurred to July 2020
- an adjustment to remove a portion of planned outage costs that are capital in nature.[2]

As the expenditure is for a network control service, it can be added to Western Power's target revenue at the next access arrangement period under the D-factor adjustment.[3] The D-factor adjustment will be approved by the ERA in 2023 as part of its final decision on Western Power's fifth access arrangement.

The ERA has included the fixed contract costs for the period 1 October 2018 to 30 June 2022 as they can be forecast with certainty for the entire period. However, the variable contract costs are dependent on the level of outages and quantities of energy dispatched. The actual variable costs for the period August 2020 to June 2022 will be available when the D-factor adjustment is approved in 2023 and can be taken account of then.

The reasons for this draft determination are set out in the remainder of this document.

As required under section 6.77 of the Access Code, the ERA is seeking public submissions before making its final determination.

1 Western Power's application has been published on the ERA's website.

2 Western Power's outage descriptions indicate that an element of the planned outages was to undertake capital works or connect new customers. These costs form part of the asset installation or customer connection and should be capitalised and recovered over the life of the relevant assets or contributions from customers.

3 The D-factor is one of the adjustment mechanisms in Western Power's access arrangement that allows certain amounts to be carried over from the previous access arrangement period.

2. Reasons

2.1 Regulatory requirements

Western Power submitted its application under section 6.76 of the Access Code, which enables a service provider to seek approval of costs outside of an access arrangement review:

> 6.76 A *service provider* may at any time apply to the *Authority* for the *Authority* to determine whether:
>
> (a) actual *non-capital costs* incurred by the *service provider* meet the requirements of section 6.40; or
>
> (b) forecast *non-capital costs* proposed to be incurred by the *service provider* is forecast to meet the requirements of section 6.40.
>
> 6.77 If an *application* is made to the *Authority* under section 6.76, then subject to section 6.80 the *Authority* must make and *publish* a determination (subject to such conditions as the *Authority* may consider appropriate) within 70 *business days*.
>
> 6.77A The *Authority* may extend the deadline in section 6.77 if, before the day on which the time would otherwise have expired, it *publishes* a notice of, and *reasons* for, its decision to extend the deadline.
>
> 6.78 Before making any determination under section 6.77, the *Authority* must consult the public.
>
> 6.79 The effect of a determination under section 6.77 is to bind the *Authority* when it approves *proposed revisions*, but in the case of forecast *non-capital costs* under section 6.76(b) the *Authority* is only bound if the actual *non-capital costs* incurred are within 5% of the forecast *non-capital costs* proposed to be incurred.

The requirements in section 6.40 are:

> 6.40 Subject to section 6.41, the *non-capital costs* component of *approved total costs* for a *covered network* must include only those *non-capital costs* which would be incurred by a *service provider efficiently minimising costs*.
>
> 6.41 Where, in order to maximise the *net benefit after considering alternative options*, a *service provider* pursues an *alternative option* in order to provide *covered services*, the *non-capital costs* component of *approved total costs* for a covered network may include *non-capital costs* incurred in relation to the *alternative option* ("**alternative option non-capital costs**") if:
>
> (a) the *alternative option non-capital costs* do not exceed the amount of *alternative option non-capital costs* that would be incurred by a *service provider efficiently minimising costs*; and
>
> (b) at least one of the following conditions is satisfied:
>
> (i) the additional revenue for the alternative option is expected to at least recover the alternative option non-capital costs; or
>
> (ii) the alternative option provides a net benefit in the covered network over a reasonable period of time that justifies higher reference tariffs; or
>
> (iii) the alternative option is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

The costs Western Power is seeking are for the access arrangement period that was submitted by Western Power in October 2017 and approved by the ERA in February 2019. Western Power did not include the network control service costs in its proposal.

Generally, differences between actual and forecast operating costs during an access arrangement period are not adjusted for at the next access arrangement period. This ensures that the service provider is incentivised to minimise costs as it keeps the benefits of any out-performance of operating cost forecasts and incurs the costs of any under-performance during the access arrangement period.

However, as the expenditure Western Power is seeking approval for is a network control service, it can be included as a D-factor adjustment to target revenue at the next access arrangement review.

The D-factor is one of the adjustment mechanisms in Western Power's access arrangement that allows certain amounts to be carried over from the previous access arrangement period. It includes any additional operating expenditure incurred from deferring a capital expenditure project or any additional expenditure for demand management or network control services. It is intended to ensure Western Power is incentivised to adopt a non-network option where that is the most efficient option without exposing customers to higher costs from inaccurate forecasts of network control services.

The D-factor provisions are set out in clause 7.6.3 to 7.6.6 of Western Power's access arrangement:

> 7.6.3 In the next access arrangement period, the Authority will add to Western Power's target revenue an amount so that Western Power is financially neutral as a result of:
>
> a) any additional non-capital costs incurred by Western Power as a result of deferring a new facilities investment project during this access arrangement period, net of any amounts previously included in target revenue in relation to the deferred new facilities investment (other than such amounts included in the calculation of the capital-related costs due to any investment difference under section 7.3.5); and
>
> b) any additional non-capital costs incurred by Western Power in relation to demand management initiatives or network control services.
>
> 7.6.4 In relation to section 7.6.3(a), the new facilities investment project that has been deferred must have been included in the forecast new facilities investment for this access arrangement period.
>
> 7.6.5 In relation to sections 7.6.3(a) and 7.6.3(b), an amount will only be added to target revenue for the next access arrangement period if there is an approved business case for the relevant expenditure, and this business case is made available to the Authority. The business case must demonstrate to the Authority's satisfaction that the proposed non-capital costs satisfy the requirements of section 6.40 and 6.41 of the Code, as relevant.
>
> 7.6.6 In relation to sections 7.6.3(a) and 7.6.3(b), the adjustment to the target revenue for the next access arrangement period must leave Western Power financially neutral by taking account of:
>
> a) the effects of inflation; and
>
> b) the time value of money as reflected by Western Power's weighted average cost of capital for the Western Power Network as determined in section 5.4.

2.2 Western Power's application

On 21 October 2020, Western Power applied to the ERA for a determination on network control service costs in the Eastern Goldfields.

The costs Western Power is seeking are for a contract with Synergy to provide back-up electricity from its West Kalgoorlie generators when there is a planned or unplanned outage on the 220 kV transmission line supplying the Eastern Goldfields. The contract ensures essential services loads and most small use customers in the Eastern Goldfields continue to receive an electricity supply when there is an outage on the 220 kV transmission line.

Western Power is seeking approval for operating expenditure of $12.3 million (nominal $) for the period 1 October 2018 to 30 June 2022. The application includes actual and forecast costs.

Western Power's business case considered the following options:

- do nothing
- construct a new 330kV rated line (double circuit) from Merredin to West Kalgoorlie
- improve emergency response
- install a battery
- arrange a network control service contract with Synergy.

The options were assessed against the following evaluation and selection criteria and ranked accordingly:

- Technical feasibility:
  - Reduce the number of customers at risk of outages.
  - Meet the service standard benchmarks and targets.
- Deliverability
  - Be ready by 30 September 2018 when the existing contract between AEMO and Synergy was due to end.
- Net present cost.
- Risk mitigation:
  - Maintain network reliability, so far as reasonably practicable, to *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* reliability obligations for the Eastern Goldfields.
  - Minimise adverse effects on corporate reputation.

Western Power ruled out doing nothing on the basis that:

- A large amount of unserved energy would occur following an unplanned outage.
- It would be increasingly challenging to obtain approvals on planned outages for conducting routine maintenance, asset replacement, network augmentation and customer connection works.
- It was likely to be non-compliant with the service standard benchmarks and result in penalties under the service standard adjustment mechanism.

Western Power ruled out constructing a new double circuit 330 kV line and installing a battery would be prohibitively expensive and unable to be delivered within the required time frame.

The option of improving the emergency response would reduce response time to fix the line fault following an unplanned outage by implementing complementary operational measures, including a spare 220kV tower and line bypass concept plan, or recruiting extra resources. Western Power ruled this option out on the basis that:

- It would not reduce the duration of outages to an acceptable level and would not address load interruptions.
- It would not effectively mitigate the risk of outage/reliability revenue penalties.

Western Power's only recommended option was to arrange a network control service contract with Synergy.[4]

In its business case, Western Power also noted the proposed investment was subject to the approval of amendments to the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005.* This is discussed further in the section below.

2.3 ERA assessment

The ERA must determine whether the costs included in Western Power's application include only those non-capital costs that would be incurred by a service provider efficiently minimising costs.

The ERA has considered the following:

- the requirement for the network support service
- whether all practicable options were considered
- the level of costs
- who should bear the cost.

2.3.1 Requirement for the network support service

As required under the Technical Rules, most of Western Power's transmission network is designed to an N-1 criterion or higher. This means the network is designed with sufficient redundancy so that the supply of electricity to customers can be maintained when there is an outage on a single transmission element.

However, the Eastern Goldfields is designed to an N-0 criterion and is supplied by a single circuit 220 kV transmission line between Merredin and West Kalgoorlie. The Technical Rules describe the N-0 criterion as follows:

> A sub-network of the *transmission system* designed to the N-0 criterion will experience the loss of the ability to transfer power into the area supplied by that sub-network on the loss of a *transmission element*. Following such an event this *power transfer capability* will not be restored until the *transmission element* has been repaired or replaced.
>
> The N-0 criterion may be applied to sub-networks with a *peak load* of less than 20 MVA and to *zone substations* with a *peak load* of less than 10 MVA. The N-0 criterion also applies to the 220 kV *interconnection* supplying the Eastern Goldfields *region*.

The Technical Rules include the following note:

> In the event of an unplanned outage of the 220 kV interconnection supplying the Eastern Goldfields region the power system is expected to split into two islands. Arrangements are in place to supply the Kalgoorlie-Boulder city and Coolgardie town loads during an interconnection outage but Users outside these areas will need to make their own arrangements for any back-up generation requirement.

[4] It was noted in the business case that Western Power had undertaken a tendering process to explore other network control service providers in the market apart from Synergy prior to preparing the business case.

In the event of an outage on the 220 kV interconnection supplying the Eastern Goldfields, a dispatch support service contract with Synergy enabled the West Kalgoorlie gas turbine units to be called on to maintain supply to the Kalgoorlie-Boulder and Coolgardie town loads.[5]

Clause 2.5.2.1(c) of the Technical Rules sets out what the service provider must do in the event of an outage on an N-0 transmission line:

> For a sub-network designed to the N-0 planning criteria, the Network Service Provider must use its best endeavours to transfer load to other parts of the transmission or distribution system to the extent that this is possible and that spare power transfer capacity is available. If insufficient back-up power transfer capacity is available, load shedding is permissible. Where a supply loss is of long duration, the Network Service Provider must endeavour to ration access to any available power transfer capacity by rotating the load shedding amongst the Consumers affected.

However, in the case of the Eastern Goldfields, load shedding has generally not been required as there is sufficient local generation that can be dispatched to meet local demand. This includes the generation available under the dispatch support service contract and other generation in the area that AEMO can dispatch “out of merit”.[6]

In 2016, the Electricity Market Review undertaken by the previous State Government, proposed a new design for the wholesale energy and ancillary service markets.[7] This included introducing arrangements similar to those in the National Electricity Market for network support and control ancillary services. On that basis it was decided to terminate the dispatch support service contract on 1 July 2018.

In May 2017, it was confirmed the West Kalgoorlie generation facilities were scheduled for retirement on 30 September 2018.

With the expected termination of the dispatch support service contract and retirement of the West Kalgoorlie generators, Western Power was concerned that planned or unplanned outages on the 220 kV transmission line could lead to customers losing supply in the Eastern Goldfields as the West Kalgoorlie generators could no longer be called on and there was likely to be insufficient local generation to support the full Eastern Goldfields load. As the proposed arrangements for network support and control ancillary services did not proceed following the change of Government in 2017, there did not appear to be an alternative mechanism that could deal with the risks to supply.

During 2017, Western Power investigated the potential for a network control service contract to manage the risk of customers losing supply. As set out in an information paper published in September 2018, by the then-Public Utilities Office, the tender responses received were either uncommercial or not compliant with the specified service requirements and, as a contingency measure, Western Power commenced negotiations with Synergy for a network control service contract.[8]

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5 The West Kalgoorlie gas turbines were commissioned in 1984, the same year the 220 kV transmission line was commissioned. The dispatch support service contract was initially between Western Power, when it was responsible for system management, and Synergy. In 2015, responsibility for system management functions, and for the dispatch support services contract, was transferred from Western Power to the Australian Energy Market Operator (AEMO).

6 AEMO can require generators that fall outside the merit bidding order to generate when required to operate the power system within specified standards and minimise load shedding.

7 Electricity Market Review, Final Report Design Recommendations for Wholesale Energy and Ancillary Market Reforms, 2016.

8 https://www.wa.gov.au/sites/default/files/2019-08/Arrangements-for-continued-power-supply-reliability-in-the-North-Country-and-Eastern-Goldfields-regions.pdf

However, as noted in the Public Utilities Office information paper, in May 2018 Western Power determined that its obligations under the Technical Rules did not require it to provide a network control service for outages on the single circuit 220 kV transmission line supplying the Eastern Goldfields.

As this could lead to adverse power supply reliability during network outages, the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* was amended to oblige Western Power to meet a temporary reliability standard in the Eastern Goldfields.

The amendment was gazetted on 25 September 2018 and applied for the period 1 October 2018 to 30 September 2023:

> 13B **Temporary reliability standards for supply to Eastern Goldfields**
>
> (1) Electricity Networks Corporation must, so far as is reasonably practicable, have in place arrangements to –
>
> (a) Restore and maintain at least 45MW of supply to essential services loads and the majority of small use customers in the Eastern Goldfields as soon as is reasonably practicable following the occurrence of an unplanned outage of a transmission element supplying the Eastern Goldfields; and
>
> (b) Maintain at least 45MW of supply to essential services loads and the majority of small use customers in the Eastern Goldfields during the occurrence of a planned outage of a transmission element supplying the Eastern Goldfields.

The amendment to the *Electricity Industry (Network Quality and Reliability of Supply) Code 2005* placed a clear statutory obligation on Western Power to provide a network control service until 30 September 2023.

The Public Utilities Office stated that a network control service contract was the most appropriate interim arrangement until the matter could be addressed under the network and wholesale electricity market reform program. The PUO noted that Western Power and Synergy were negotiating the terms of a five-year contract.

2.3.2 Options considered

As set out in its business case and summarised above, Western Power included several options but considered a network control service contract with Synergy was the only viable option.

The ERA sought advice from consultancy Geoff Brown and Associates on any other alternative options that Western Power should have considered.

Western Power did not include demand management as a potential option in its business case.

It was also not considered by Western Power prior to preparing the business case.[9] Western Power's advertisement, published in June 2017, seeking parties interested in tendering for network support services was focussed on generation options. For example, the advertisement stated that proposals must be able to export 45MW into the system and be able to support the system frequency and voltage of the islanded network.

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9 The business case was prepared in May 2018 and approved by the Investment Review Committee on 22 August 2018 and by the Board on 3 September 2018.

Geoff Brown noted the advantages of demand management:

- It did not require reserve generation to be mobilised.
- The quantity of load called on for curtailment would depend on the actual demand at the time the interconnector was lost, which was likely to be less than the full quantity available.

Given the timeframe Western Power was working to, it would have been challenging to develop a demand management option. Impediments included:

- As no one customer was likely to have the 45MW of curtailable demand, there would need to be a number of different contracts, each of which would take time to negotiate and put in place.
- Western Power did not appear to have a commercial structure in place for the management of curtailable demand.

The ERA considers demand management should have been considered but accepts that, given the timeframes, it was not possible for Western Power to find an alternative to the Synergy contract.

However, the initiatives from the State Government's Energy Transformation program, including the changes to the regulatory framework, will enable a much broader consideration of options for the future. The ERA expects future proposals for ensuring security of supply in the Eastern Goldfields will properly identify and consider all the alternative options.

2.3.3 Level of costs

Western Power's application was based on the five-year forecast in its business case, adjusted to reflect actual expenditure for 1 October 2018 to 31 March 2020 and forecast expenditure from 1 April 2020 to 30 June 2022.

The ERA obtained details of the contract pricing and invoices. The contract includes a fixed element for making the generation available and variable charges that apply when the generation is called upon.

As required under the Wholesale Electricity Market Rules, Western Power was required to provide details of the contract (excluding price) to AEMO, which is responsible for issuing instructions when the units are required as set out in the contract.[10] AEMO can only dispatch the West Kalgoorlie generators if there is an outage on the 220 kV transmission line and not for any other power system security reason.

The units were commissioned in 1984 and, as discussed above, it was intended they would retire in 2018. They are no longer registered for capacity credits and do not pay network charges as they are only entitled to network access as required to support power system supply reliability during network outages. As the assets are reaching the end of their technical life, the capital costs would be expected to be minimal, although some expenditure may be needed to keep them in service.

The generators are open-cycle gas turbines capable of running on either gas or distillate. However, they are operated on distillate as they do not have a gas supply. One unit also has black start capability.[11]

[10] Eastern Goldfields Network Control Service details provided to AEMO

[11] A black start is the ability to restore power independently after a total or partial shutdown.

As noted above, Western Power undertook a tendering process to explore other potential network control service providers in the market apart from Synergy. The ERA has reviewed the tenders received. While a like-for-like comparison with the Synergy contract cannot be made, the ERA is satisfied that the Synergy contract price is lower than could have been obtained from new and existing generators who submitted tenders.

To further assess the reasonableness of the costs, the ERA has compared the contract prices against the:

- benchmark reserve capacity price (excluding an element of capital costs)
- Alternative Maximum STEM price
- prices in the previous dispatch support service contract.

The contract prices are within or below these comparisons.

Based on this analysis, the ERA considers the contract prices do not exceed the amount that would be incurred by a service provider efficiently minimising costs.

Besides contract price, the number and duration of outages also affects the level of costs.

The ERA obtained details and costs for the outages that have occurred between October 2018 and July 2020. There have been five planned outages and no unplanned outages. The outage periods ranged from one day to three days.

Western Power advised the costs for outages during the first 18 months of the contract were much lower than forecast as it had:

- Coordinated planned maintenance resulting in reduced frequency, duration and generation requirements.
- Scheduled outages to install assets or connect customers concurrently with planned maintenance works.

As noted above, Western Power's application was based on its business case with some adjustments. Western Power's business plan forecast included $0.3 million for internal administration costs and a risk allowance of $1 million.

The ERA has not approved the internal administration costs. It is a very small amount in comparison to Western Power's total administrative operations and should be able to be absorbed in normal operations. The application did not demonstrate that the contract required any new internal administrative expenditure.

The risk allowance is not necessary as the final costs will be known when the adjustment is made at the next access arrangement review.

Based on the information in the contract and invoices it has obtained from Western Power, the ERA has extracted actual variable and fixed costs to July 2020 and forecast fixed costs to 30 June 2022. This amounts to $10.3 million.

The fixed contract costs can be forecast with reasonable certainty for the entire period.[12] However, the variable contract costs are dependent on the level of outages and quantities of energy dispatched. The approved network control service costs will be added to Western Power's target revenue in the next access arrangement period. The actual variable costs for

[12] It includes forecast CPI which may vary, however, the effect of any likely differences will be immaterial.

the entire period will be available when that adjustment is made and can then be taken into account.

2.3.4 Who should bear the costs

Western Power has proposed the total costs should be added to target revenue as part of the D-factor adjustment. This would result in the costs being recovered through network charges over the next access arrangement period.

The ERA considers that a portion of the variable network control service costs is attributable to:

- planned outages for asset replacement and augmentation, and
- planned outages for customer connections.

The proportion of costs attributable to these outages forms part of the asset installation or connection cost and should be included in the capital costs of the new assets and recovered over the life of the relevant assets or included in the cost of connection and recovered from the relevant customer.

Based on the information provided by Western Power on the planned network outages, the ERA has estimated the portion of costs attributable to asset replacement or augmentation and customer connections is $0.5 million.

After making this adjustment, the approved non-capital costs that will be included in the D-factor adjustment at the next access arrangement review is $9.8 million.