24 July 2020

Dear Stakeholders,

Project EnergyConnect Update

Project EnergyConnect (PEC) is the proposed, new, 330-kV electricity interconnector between Robertstown, in South Australia, and Wagga Wagga, in New South Wales, that also includes a short 220-kV spur from Buronga, in New South Wales, to Red Cliffs in northwest Victoria.

Background

In 2016, ElectraNet began exploring options to reduce the cost of providing secure and reliable electricity, enhance power system security in South Australia, and facilitate the long-term transition of the energy sector across the National Electricity Market (NEM) to low emission energy sources.

In November 2016, we released a Project Specification Consultation Report (PSCR) that explored the technical and economic feasibility of a new interconnector between South Australia and the eastern states as well as other non-network solution options, through the SA Energy Transformation Regulatory Investment Test for Transmission (RIT-T).

The RIT-T is the economic cost benefit test that is overseen by the Australian Energy Regulator (AER) and applies to all major network investments in the NEM.

In June 2018, a Project Assessment Draft Report (PADR) was released identifying that the construction of a new, high-capacity interconnector between South Australia and New South Wales would deliver substantial net benefits to customers.

In February 2019, following extensive consultation with stakeholders we released a Project Assessment Conclusions Report (PACR) as the final step in the RIT-T process.

The RIT-T PACR estimated the cost of the project to be $1.53 billion with a completion date of 2022 to 2024.

To deliver the project, ElectraNet is partnering with TransGrid, the manager and operator of the high voltage electricity transmission network in NSW. Should the project be approved, TransGrid would fund the works within its jurisdiction.

In April 2019, ElectraNet requested the AER make a determination under clause 5.16.6 of the National Electricity Rules (Rules) that the preferred option[1] identified satisfies the requirements of the RIT-T. This step was necessary as a precondition for ElectraNet and TransGrid to seek contingent project funding from the AER.

On 24 January 2020, the AER approved the RIT-T describing the business case for project as “robust” and determining that the proposed interconnector remained the most “credible option that maximises the net economic benefit” in the NEM, ultimately benefiting electricity customers.

[1] The preferred option is defined in clause 5.16.1(b) of the Rules as the option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

While the AER concluded that it is “satisfied the RIT-T has been successfully completed”, it noted that “any significant changes to the costs of the preferred option could have a material impact on the outcome of the RIT-T”.

The AER’s RIT-T determination is available on the AER website at www.aer.gov.au.

Updated Cost Benefit Analysis

The Rules require ElectraNet to consider whether, in its reasonable opinion, there has been a “material change in circumstances” that might lead to a change in the preferred option and thereby potentially require reapplication of the RIT-T.

Since the RIT-T was concluded with publication of the PACR in February 2019 there have been significant changes in both project costs and benefits from what was assessed in the RIT-T.

ElectraNet has been investigating whether there has been a “material change of circumstances”, taking into account this new information on both costs and benefits.

This has involved working closely with the Australian Energy Market Operator (AEMO) to update key variables and inputs that impact on the market benefits of the project to align with its 2020 Integrated System Plan (ISP). We are aligning our analysis to be consistent with the 2020 ISP to the extent practicable. Appendix A provides a summary of key changes made.

Firm project cost estimates for the works in South Australia and New South Wales are required to conclude the updated cost benefit analysis.

Both ElectraNet and TransGrid are committed to delivering Project EnergyConnect at the lowest possible cost to customers. However, there is a general increase in transmission costs being experienced across the NEM, with AEMO reporting in a stakeholder update on 30 April 2020 that it was incorporating an approximate 30% increase in transmission capital costs in its Final 2020 ISP for all ISP transmission projects.

Both ElectraNet and TransGrid have been working through competitive procurement processes with construction contractors to firm up capital cost estimates that will form the basis of applications to seek contingent project funding from the AER. These cost estimates are expected to be available by September 2020.

In the meantime, we will progress our updated cost benefit analysis based on a range of expected cost outcomes.

Thermal Generator Variable Heat Rates

In its RIT-T determination the AER disagreed with applying Minimum Capacity Factors (MCFs) to SA Gas Powered Generation (GPG) in the modelling of market benefits.

We have, therefore, removed the use of MCFs from the updated cost benefit analysis, and instead have worked closely with AEMO to consider a more accurate representation of SA GPG operation with MCFs removed.

This includes replacing fixed (or static) heat rates for thermal generators with variable heat rates that more accurately represent plant behaviour at different levels of generator output.

Both ElectraNet and AEMO are now including variable heat rates for all thermal generators in the NEM in their market modelling where relevant[2] – this provides a more accurate representation of operating efficiency and therefore fuel costs.

Previously, thermal generators were modelled based on their level of efficiency at full output regardless of their output level – this underestimates fuel consumption and therefore costs because thermal plant (especially GPG in SA) increasingly operates at lower levels of output that is relatively less efficient and burns more fuel at these lower levels of output.

AEMO derived variable heat rates for all existing generators in the NEM from input/ output curves of new entrant technologies provided by GHD[3]. ElectraNet engaged Aurecon to provide independent advice on variable heat rates and other technical plant characteristics [4]. This advice aligns closely with AEMO's calculated values. Some differences were observed on gas power steam turbines and brown coal plant. However, these differences are not material enough to vary from the most recent ISP parameters.

Both the AEMO derived variable heat rates and the Aurecon report accompany this stakeholder update.

Appendix B also provides more information on thermal generator variable heat rates.

South Australian System Security Requirements

AEMO has identified new emerging system security requirements for South Australia due to the continuing growth of distributed energy resources and reducing minimum demand levels[5]. We are including these new requirements in our updated cost benefit analysis.

AEMO's report to the Government of South Australia recommends PEC proceeds as an "essential foundational measure" to address the system security risks identified. PEC would reduce the likelihood of South Australia islanding from the NEM and alleviate the most challenging system security issues identified in AEMO's analysis.

On 19 June 2020, the SA Government announced a plan entitled *South Australian Energy Solution – A secure transition to affordable renewable energy* to address the advice provided by AEMO. A central feature of this is a commitment to implement Project EnergyConnect.

Stakeholder Engagement

ElectraNet remains committed to engaging with stakeholders on Project EnergyConnect, including on our updated cost benefit analysis.

---

2 AEMO has applied variable heat rates in its time-sequential market modelling for the Final 2020 ISP to most thermal plant. AEMO has continued to apply simple heat rate curves for small, modular gas-powered generators including Hallett and Barker Inlet plant in South Australia. ElectraNet has taken a similar approach.

3 GHD, "AEMO revised, 2018-19 Costs and Technical Parameter", available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/InputsAssumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xls

4 Aurecon, Generator Technical and Cost Parameters, July 2020.

5 Minimum Operational Demand Thresholds in South Australia, advice prepared for the Government of South Australia, April 2020.

We will provide more details on our updated analysis soon after AEMO releases its Final 2020 ISP, which is expected by 30 July 2020. This will include an invitation to register to attend a stakeholder forum in August at which we will share the results of our updated cost benefit analysis and how these results were derived.

ElectraNet and TransGrid are working towards submitting complete contingent project applications to the AER as soon as practicable after firm project cost estimates for the works in South Australia and New South Wales have been finalised.

<u>Invitation to Provide Written Comments on Thermal Generator Variable Heat Rates</u>

While we welcome stakeholder engagement on any aspect of our updated cost benefit analysis, we are specifically inviting submissions on the application of variable heat rates to thermal generators in the time-sequential market modelling of our updated cost benefit analysis.

If you would like to make a submission on this topic, then please send it to the address below by 7 August 2020.

<u>How to Contact Us</u>

If you have any comments or questions in relation to ElectraNet's updated cost benefit analysis for PEC or any other aspect of this stakeholder update then please contact us at consultation.enet@electranet.com.au and we will be happy to arrange an opportunity to discuss.

Rainer Korte
Group Executive Asset Management

24 July 2020

ElectraNet

Appendix A: Summary of changes made to project benefits assessment

ElectraNet's updated cost-benefit modelling is consistent with the inputs and assumptions of AEMO's Final 2020 ISP. Changes compared to the RIT-T assessment include those summarised in the following table.

Key Changes	Source	Comments
1. Demand forecasts	Final 2020 ISP	Demand forecasts have been updated in line with the 2020 ISP.
2. Committed generation projects	Final 2020 ISP	Committed generation projects throughout the NEM have been updated in line with the 2020 ISP.
3. Thermal generator variable heat rates	Final 2020 ISP	Minimum Capacity Factors (MCFs) applied in the PACR were a proxy for plant characteristics that were not otherwise modelled. We have replaced fixed (or static) heat rates with variable heat rates in the time sequential modelling in line with the 2020 ISP. ElectraNet engaged Aurecon to provide independent advice on variable heat rates that supports the AEMO 2020 ISP heat rate data.
4. Gas prices	Final 2020 ISP	Gas price forecasts have been updated in line with the 2020 ISP. ElectraNet engaged EnergyQuest to provide independent advice on gas price forecasts that supports the AEMO 2020 ISP data.
5. Coal prices	Final 2020 ISP	Coal prices have been updated in line with the 2020 ISP.
6. New entrant generator capital costs	Final 2020 ISP	New entrant generator capital costs, including pumped hydro and battery energy storage costs have been updated in line with the 2020 ISP.
7. Transmission capital costs	Final 2020 ISP	The capital costs of ISP transmission projects have been updated in line with the 2020 ISP.
8. Renewable Energy Targets	Final 2020 ISP	Includes consideration of the latest Queensland, Victorian and Tasmanian Renewable Energy Targets in line with the 2020 ISP.
9. Renewable Energy Zones	Final 2020 ISP	Includes consideration of the NSW Central-West Orana REZ expansion in line with the 2020 ISP.
10. New emerging system security requirements in South Australia	Final 2020 ISP	We are including new emerging system security constraints identified by AEMO in our updated cost benefit analysis in line with advice in the 2020 ISP.
11. PEC capital cost forecasts	Competitive market pricing	Project capital cost forecasts are largely based on competitive market pricing that is expected to be firmed up by September 2020.

Appendix B: Thermal generator variable heat rates

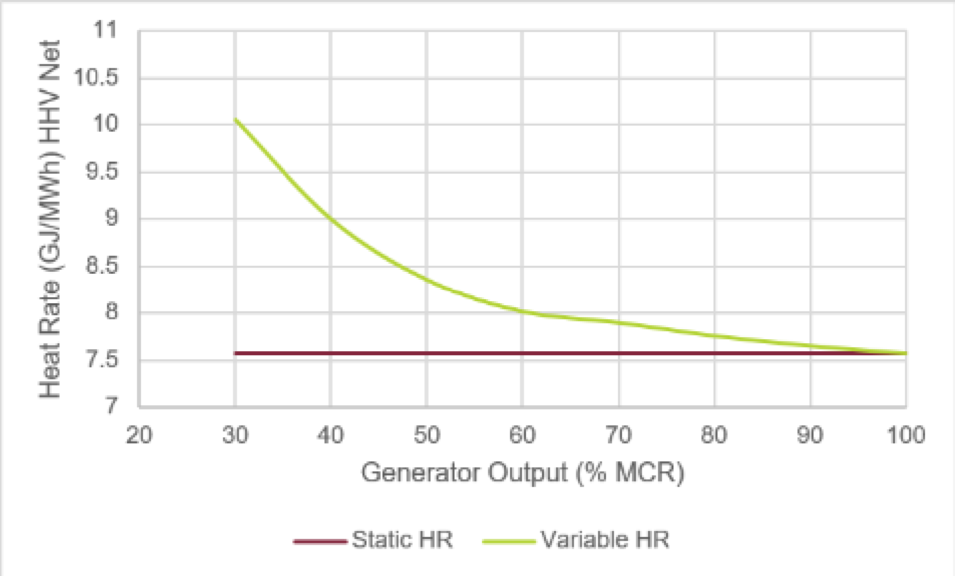
The heat energy input taken to produce a single unit of electric energy output is called the heat rate of the thermal generating unit and is expressed in GJ/MWh as shown in the following equation:

Heat Rate = (Heat Input from Fuel (GJ))/ (Electric Energy Output (MWh))

The heat rates of thermal units depend on their level of dispatch as shown in Figure 1 with a higher heat rate reflecting lower efficiency as proportionally more energy input is required per unit of electrical output.

A thermal unit usually has higher heat rate at light loading levels reflecting reduced efficiency.

Figure 1: GHD 2018 heat rate curve of Combined Cycle Gas Turbine unit



The RIT-T PACR technical and cost parameters for generators were sourced from AEMO's 2018 ISP Assumption Workbook, which published fixed (or static) heat rates for all existing and potential new entrant technologies. With increasing levels of intermittent generation, existing thermal plant is expected to operate to fill the gaps by frequently ramping up and down between minimum stable levels and maximum operation.

Updating heat rate values to reflect how heat rates vary with the level of generator output improves the modelled accuracy of plant behaviour and consequently the estimation of market benefits.

ElectraNet and AEMO have explored the use of variable heat rates with AEMO determining variable heat rates for all existing generators in the NEM. AEMO derived these values from GHD advice based on the shape of variable heat rates for generic new entrant generators[6].

The GHD generic curves were converted into linear marginal heat rates, from which the intercept – obtained by dividing the Heat Rate Base by the nameplate capacity (Max Capacity) – was taken as a 'shape' parameter. This was then scaled by the maximum capacity of each unit with an incremental heat rate chosen to match the generator efficiency at maximum output.

6 GHD, "AEMO revised, 2018-19 Costs and Technical Parameter", available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/InputsAssumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xls

For CCGTs the no-load heat rate and incremental heat rate of the gas turbines were chosen so that the plant average heat rate curve matches the generic GHD CCGT 'shape' parameter and the total plant maximum matches the GHD heat rate at maximum output. The steam turbine component of the CCGTs uses a static heat rate that results in the best fit to the generic CCGT curve provided by GHD. Under this methodology the gas turbines of CCGTs have similar heat rate curves to standalone OCGTs.

GHD doesn't provide a generic curve for Gas Fired Steam Turbines such as Newport and Torrens Island. Therefore, a different approach was used to derive variable heat rates of these power stations. AEMO used Gas Bulletin Board and electricity Market Management System data and estimated the no-load and incremental heat rates based on observed gas usage.

AEMO will provide more information on the method used in the 2020 upcoming ISP.

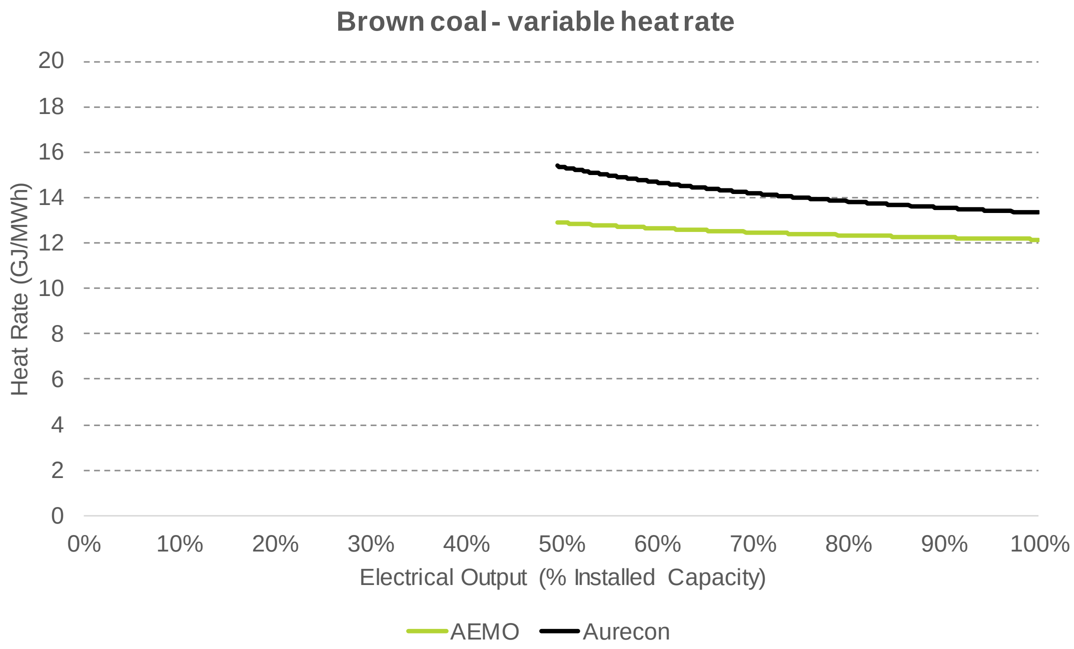
ElectraNet engaged Aurecon to provide independent advice on variable heat rates and other technical plant characteristics [7]. This advice aligns closely with AEMO's calculated results.

Some differences were observed on gas power steam turbines and brown coal plant. However, the differences are not material enough to vary from the most recent ISP parameters.

The most substantial difference occurs between brown coal units with Aurecon advising a general and almost constant increase in heat rate across all operating ranges. The difference is highlighted in

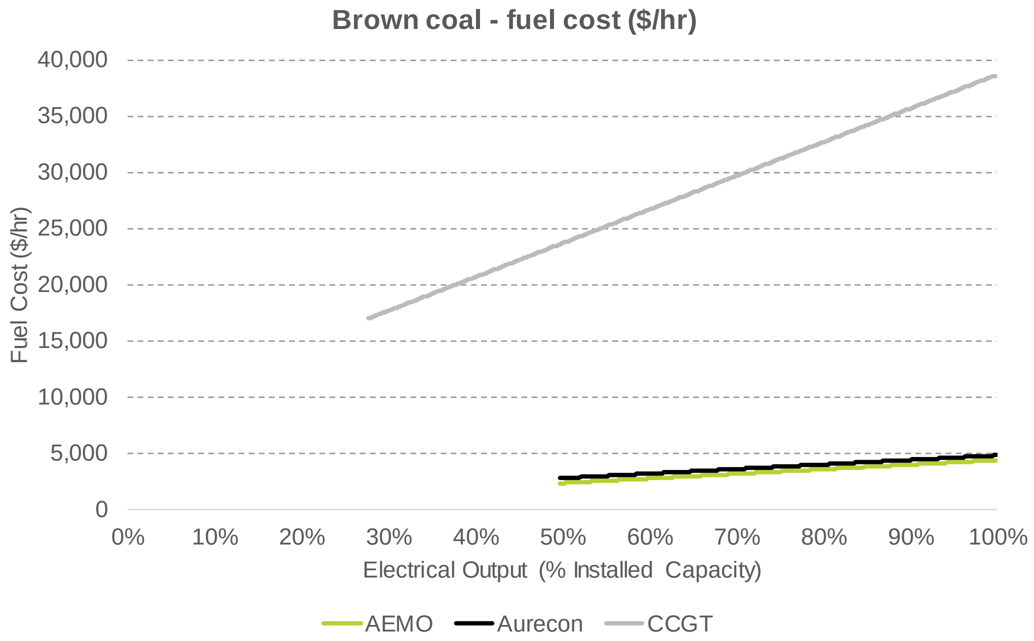
Figure 1. However, given brown coal's low fuel costs, this has no material impact on the estimation of benefits of PEC. This is demonstrated in Figure 2 that shows the effective difference in the costs of dispatching a brown coal unit for 1 hour with the equivalent information of a CCGT unit for comparison.

Figure 1 – Heat rate comparison between Aurecon and AEMO for brown coal



[7] Aurecon, Energy Connect Technical Assistance – Technical and Cost Parameters, July 2020.

Figure 2 – Brown coal comparison between the cost to operate for an hour from Aurecon and AEMO



Gas boiler steam turbine heat rates show strong alignment at maximum output between AEMO and Aurecon. At low output levels Aurecon reports a slightly lower heat rate. However, as discussed by Aurecon, observed gas usage and electrical consumption have reflected higher heat rates at times than would be predicted using the Aurecon model.

The possible reasons for the differences between modelled and observed results therefore support the use of AEMO's values. Figures 3 and 4 highlight the differences in heat rates between minimum stable load and the maximum load (as a percentage) for gas power steam turbines and the approximate cost of operating the plant for an hour at the different operating levels.

As can be seen, the divergence in heat rates does not lead to a significant cost difference to operate the plant at a given level of output.

Figure 3 – Heat rate comparison between Aurecon and AEMO for gas fired steam turbines

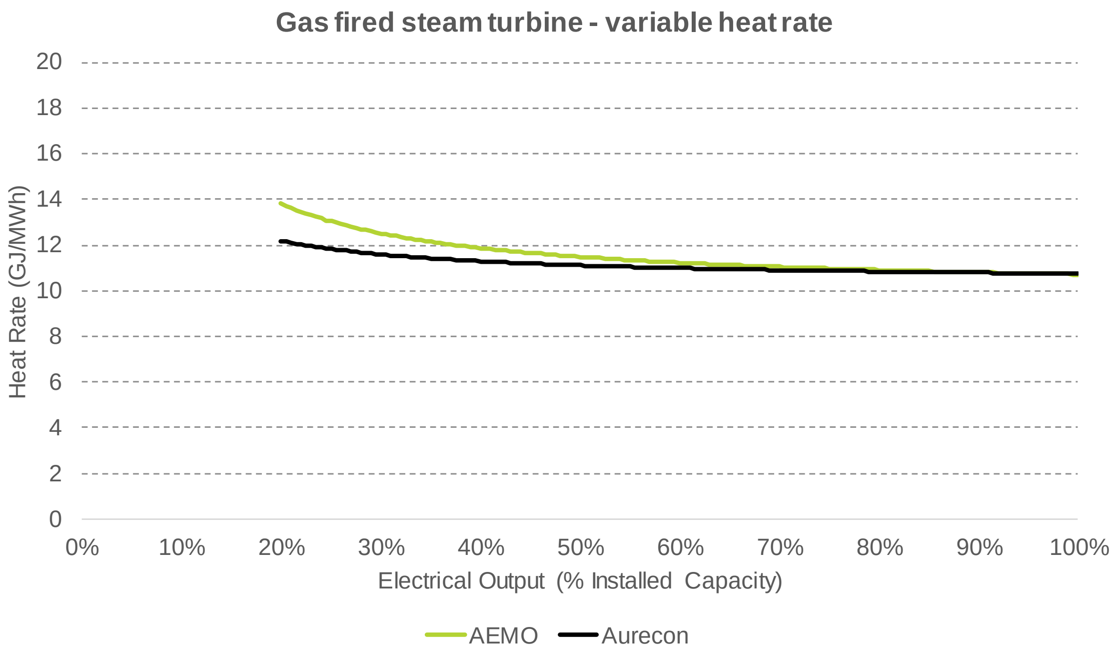
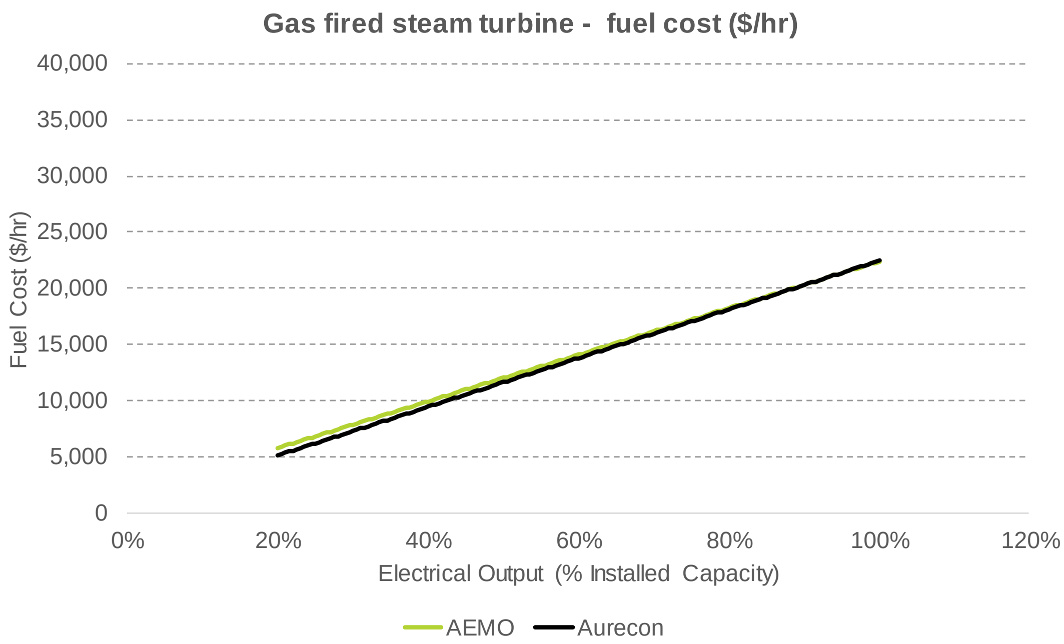


Figure 4 – Gas powered steam turbine comparison between the cost to operate for an hour from Aurecon and AEMO



Heat rates for Combined Cycle Gas Turbines (CCGT) and black coal units show strong alignment between AEMO and Aurecon as demonstrated by Figures 5 and 6.

Figure 5 - Heat rate comparisons between CCGTs from AEMO and Aurecon

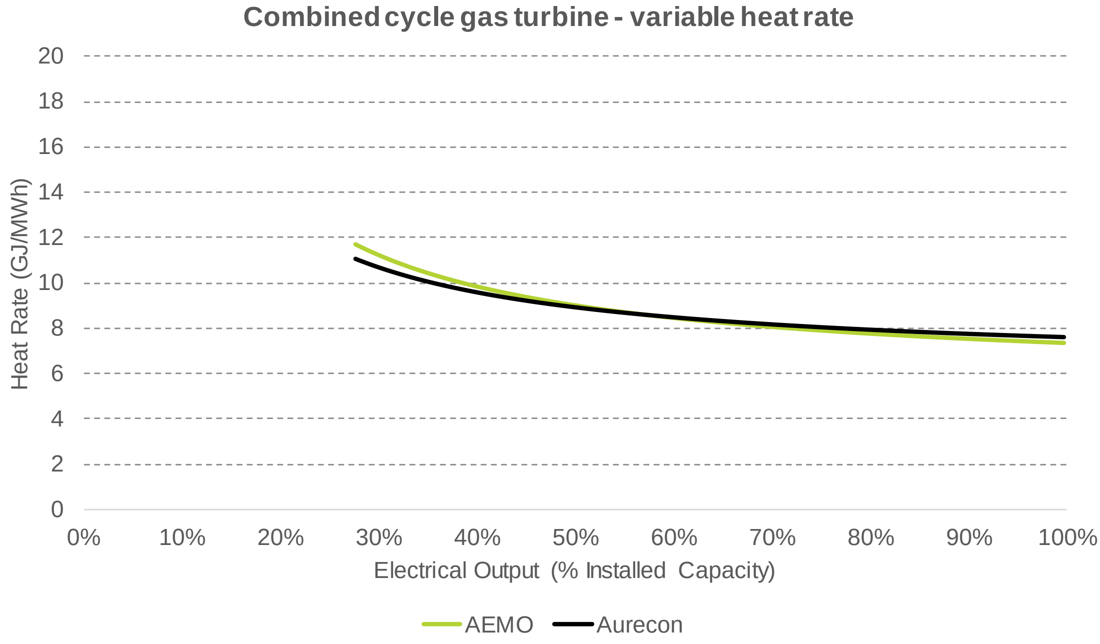
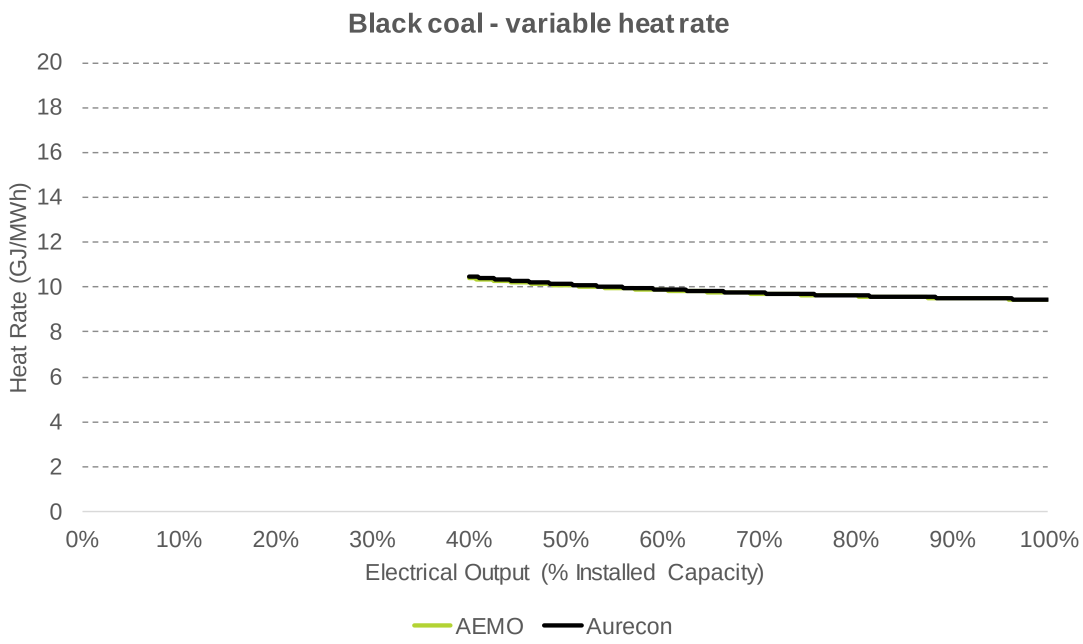


Figure 6 - Heat rate comparisons between black coal from AEMO and Aurecon



From this ElectraNet concludes that the independent Aurecon analysis supports the use of AEMO's 2020 ISP dynamic heat rates for thermal generators to provide a more accurate representation of operating efficiency and therefore fuel costs in the economic modelling analysis.