16 February 2023

Our Ref: ASTRI_CS_0012 (16022022)

AEMO ISP Team
Forecast Planning
Level 22. 530 Collins Street
Melbourne VIV 3001

Dear AEMO ISP Forecast Planning Team

Subject: Joint ASTRI, AUSTELA and Fichtner Engineering Feedback on AEMO 2023 draft Inputs Assumptions and Scenarios Report

Thank you for the opportunity to provide feedback on the AEMO 2023 draft Inputs Assumptions and Scenarios Report. The specific focus of our feedback relate to the cost model proposed for Concentrating Solar Power (CSP) systems.

In October 2022, the Australian Solar Thermal Research Institute (ASTRI) engaged Fichtner Engineering, together with ITP Thermal to prepare an independent assessment of the value that CSP could provide as part of an integrated approach to decarbonization of Australia's power and heat requirements. The intent was to examine whether CSP can deliver value within Australia's future energy systems and, if so, the best way to capture that value in combination with an integrated mix of renewable technologies.

While the Fichtner Team have developed detail cost models for CSP integration within remote mining, industrial process heat and Renewable Fuels, it is there cost model for CSP integration into utility scale, grid connected power systems that is relevant to this submission.

For utility scale power generation the Fichtner Team has developed a detailed cost model based on real world cost data, cost drivers, and scaling exponents from a large number of international CST projects, budget quotes and recent stakeholder engagement, incl. Vast Solar, Cosin Solar, BSE, Sener, JC, NREL, IRENA. The reference cost data has been CPI adjusted and international cost data transferred, applying exchange and country factors (Compass International).

In essence, the Fichtner CSP cost model represents that most accurate, detailed and up to date assessment of CSP deployment costs within Australia. The cost model allows for user inputs and associated costs for different locations, size, storage duration and solar multiples. The Fichtner Team have spoken with the Aurecon Team looking at the CSP costings, and the Aurecon Team believe that the model is a welcome addition to understanding real world deployment costs for CSP within Australia's power networks.

With respect to the ASTRI, Fichtner, and ITP Submission, there are three key issues that we would like to raise and which are further expanded on in this submission. The three issues are as follows:

1. **CSP costs in the AEMO Draft 2023 Input Assumptions and Scenario Report**

   We notice that the CSP cost data in the three datasets (i.e. AEMO, GenCost and Aurecon) differ. As per other technologies, we would have expected the cost to be the same for all three datasets. We request that the costs be aligned, or that an explanation be provided to explain the difference.

2. **Requirement for additional CSP configurations for the ISP modelling**

   CSP can be used in different end-use configuration depending on the system requirements at the deployment location. It can run as a night-time only system, a day/nighttime system (e.g. as CSP-PV Hybrid) and systems can have different storage durations and solar multiples. The current AEMO cost model does not take into account any of these different deployment configuration. While AEMO has four battery configurations, there is only one single CSP configuration.

   We do not believe that a single deployment configuration is appropriate for the ISP. We believe that at least four different CSP configurations should be modelled. Without additional configurations, we believe that the ISP modelling creates an unfair bias towards batteries compared with other potentially more cost effective longer duration, intra-day storage technologies. We therefore request that additional configuration be added and we are happy to provide the Fichtner cost model and further support to AEMO to derive additional configurations.

3. **Refinement of CSP configuration using recommended CSP cost model**

   We have analysed the assumption and data used by AEMO, Fichtner and GenCost to derive your CSP Cost Model. We believe that there are some discrepancies in the way that storage duration and solar multiples have been applied. We also believe that there is more accurate real-world cost data on key equipment elements of CSP (i.e. heliostats, storage, power blocks etc). As mentioned, the Fichtner Team has spoken to Aurecon who are willing to work with the Fichtner Team to ensure that the most accurate / appropriate data and assumptions are used. We also extend this offer to AEMO, and would be willing to provide the cost model to your forecast planners to allow for better refinement and more accurate assessment of CSP deployment costs.

These three issues are further expanded below.

1. CSP costs in the AEMO Draft 2023 Input Assumptions and Scenario Report

We note that on reviewing the draft numbers provided by Aurecon (2022 Costs and Technical Parameter Review - December 2022), Gencost (January 2023) and in turn the draft IASR on which AEMO is now seeking feedback, it is apparent that for most technologies the specific cost per kW installed that can be deduced from the Aurecon base system CAPEX numbers including land and development costs divided by the net generation, is in agreement with that published by Gencost for December 2022 and in turn the same as the draft numbers presented by AEMO for projects hypothetically contracted in FY 2022-23. However there is a discrepancy in the case of CSP and some other technologies.

The table below compares some key examples with the CSP costing in the bottom row.

Technology	Aurecon Dec2022 draft net basis ($/kW$_e$)	Aurecon Dec2022 draft net basis incl land and dev costs ($/kW$_e$)	Gencost 2023 Draft for "2022" ($/kW$_e$)	AEMO 2023 Draft for "2022-23" ($/kW$_e$)
Battery storage (1 hr)	880.1	930.7	931.0	931.0
Battery storage (2 hrs)	1,295.1	1,345.9	1,346.0	1,346.0
Battery storage (4 hrs)	2,134.2	2,185.5	2,184.0	2,184.0
Battery storage (8 hrs)	3,829.9	3,882.1	3,880.0	3,880.0
Gas combined cycle	1,620.0	1,765.8	1,766.0	1,766.0
Gas open cycle (large)	865.0	942.8	943.0	943.0
solar PV Large scale	1,483.0	1,572.0	1,572.0	1,572.0
Solar thermal (15hrs)	**7,333.3**	**7,444.4**	**8,265.0**	**8,265.0**

The reason for this inconsistency between Aurecon, Gencost and AEMO for the CSP case is not clear and seek clarification.

We would argue that the Aurecon numbers appear more realistic than the higher Gencost / AEMO number, However in any case we wish to present a new cost model based on an up to date analysis just completed.

2. Requirement for additional CSP configurations for the ISP modelling

We further note in the draft IASR that the configuration is specified as

'' Solar Thermal Central Receiver with storage (15hr) ''

with the further commentary that;

'' The storage component is proposed to be increased from 8hr in the 2022 ISP. Additionally, as discussed in more detail in Section 0, in response to stakeholder feedback the behaviour of this technology will be modified to place greater emphasis on generating at peak and night times."

A move to recognize that CSP offers greater value in long duration storage configurations makes sense, however we note that use of a single configuration to model a technology which, like batteries and PHES, can be configured with any desired duration of storage duration is problematic as it requires second guessing what the best configuration is. Capacity expansion optimisation modelling could produce vastly different results of predicted future installed CSP capacity if the choice is limited to a single configuration that may ultimately not be the optimum for cost effective benefit to the system.

We would suggest that 4 or more CSP configurations each be represented with their own cost number.

Modelling the dispatch behavior appropriately is also important. The draft IASR notes in this regard:

''AEMO's capacity outlook modelling for the 2022 ISP used static discharge traces to represent operation. Stakeholder feedback has suggested modifications to the assumed operation of this technology are needed, charging during sunlight hours and discharging at night. AEMO proposes to modify the static discharge traces to reflect this behaviour, such that they are optimised to discharge at night and during periods of high demand. If reasonable adoption of the technology occurs, subsequent simulations will include it as a controllable storage object to better represent its operation.''

We would argue that static traces do not represent the manner in which a real system would be used strategically. In ISP and other similar capacity expansion modelling, **CSP plants should have their dispatch optimized in each time step as other storage technologies and peaking plant presumably do**. If the final sentence above regarding *''including it as a controllable storage object'''* would do this then we would encourage that as the default approach.

3. Refinement of CSP configuration using recommended CSP cost model

The precise configuration on which AEMO's CSP numbers are based does not seem to be clear, however Aurecon's report indicates that what they have considered is a system of 180 MWe net, with 15 full load hours of storage and a solar field that appears to be sized with a solar multiple of 2.4. We would note that the plant configuration described is bigger than any single tower plant that has been built. However if it is to be interpreted as describing a single development that could involve two or more towers then that would be realistic.

The stated intention to place greater emphasis on peak and night time generation is well founded. Whilst the logic of configuring as a peaking plant is valid, on going capacity expansion modelling by our team is currently suggesting large storage durations and large solar fields may actually be preferred. This again highlights the desirability of including several configurations with their respective cost estimates for the ISP modelling.

In presenting a cost model for a CSP system it is important to understand that the system is comprised of three basic subsystems which can have their sizes chosen independently when designs are optimised to market condition and customer requirements.

Specifically these are:

- Solar field thermal capacity in $MW_{thermal}$;
- Thermal energy storage (TES) capacity in $MWh_{thermal}$; and
- Power Block and balance of plant capacity in $MW_{electrical}$.

Specific cost figures have been determined for a solar tower reference plant, based in NSW (medium regional cost adder - NSW medium), using a more complex cost model. Using this cost model, the total overnight cost is calculated and broken down into the three cost portions solar field, thermal energy storage and power block. I.e. the derived specific cost figures for the reference plant include both direct and indirect cost.

Based on the assumption of an EPC procurement, a total of 20% of indirect cost are considered for the EPC cost. On top of the EPC a total of 5% of owner's cost are added for the reference plant configuration, incl. land cost, development cost, utility connections and additional owner's cost during construction and commissioning.

Given the global supply chain issue and related cost escalations, also reflected in the Draft 2023 Inputs, Assumptions and Scenarios Report, to be used in AEMO's 2023/2024 Forecasting and Planning publications for the NEM, an additional escalation factor of 13% is considered. Given there is little recent CSP cost data available, a similar cost escalation as for a CCGT plant has been assumed. Further, scaling exponents are provided for each of the three cost portions. For a new plant configuration, i.e. capacities for each portion, the new cost figures are calculated, applying the scaling exponents on the specific cost figures of the reference plant. The principle is:

(Subsystem Capital Cost) = (Base Subsystem Capital Cost) x (Subsystem size/Base Subsystem size)^n

For CSP system built in a location where the cost of construction is equivalent to ''NSW Medium'' our draft model for estimation of the contract cost at the end of 2022 (FY 2022-23), including land and development costs is given by:

Item	Unit	*Reference Value*	Specific Cost [A$/UNIT]	*Scaling Exponent*
Power block	MW_e	*140*	2,028,795	***0.70***
Thermal energy Storage	MWh_t	*4,667*	35,880	***0.85***
Solar Field	MW_t	*720*	644,230	***0.88***

The draft 2023 IASR presents regional cost factors for equipment and construction etc. We assume these are well founded and take them at face value. Based on the split between equipment and installation for a CSP plant and the regional cost factor of VIC Low compared to NSW medium. The factor for converting the basic costs derived using the formulas above is 94.1%

Using this general model, we recalculated the plant configuration presented by Aurecon with 180°MWnet, 15 hours of storage and a solar field of 2,200,000 m², resulting in approximately a solar field capacity of 1,200 MWt[1]. As regional cost factor ''Vic Low'' is considered, as this is the "reference location" for the IASR. The resulting specific cost number amount to 6,937 AUD/KWnet, compared to 7,444 AUD/KWnet.

Noting our recommendation to consider at least 4 options, we will use this model to select suitable (pre-optimized) plant configurations, suitable in the ISP study.

Future Cost Reduction:

Our suggested cost reduction curve is based on the latest IEA World Energy Outlook and the provided CST deployment projection as part of the Announced Pledges Scenario (APS) Scenario. For the learning rate 15% is considered until 2035 and thereafter 10%. In normalised terms this produces a slightly lower 2050 value that the version for the draft IASR. However we note that predicting the future cost reduction trajectory is the most uncertain part of such exercises. The relative cost of technologies in future years is the main determinant of the predictions of take up of technologies. Thus it is important that results of capacity expansion modelling are presented in a way that acknowledges this uncertainty.

[1] Resulting solar field capacity exceeds the techno-commercial viable optimum

O&M costs:

It appears that O&M costs are largely presented as fixed costs per MW per year.

It would appear however that past ISP modelling has not applied any cost reduction to O&M costs year by year. This is somewhat perverse. It is certainly the case that a learning curve of cost reduction should apply to O&M as it does to Capex. In the absence of a more specific model we suggest they should reduce in proportion.

The number for CSP appears reasonable, However we recommend re-casting O&M costs as a % of capex per year. In that way plants with different solar field sizes but the same nameplate capacity will have suitably scaled O&M costs. It will also allow the O&M costs to reduce year by year in proportion to capex reductions, which we argue is a reasonable default model.

Conclusion

In conclusion, we again thank you for the opportunity to provide feedback on the AEMO 2023 draft Inputs Assumptions and Scenarios Report (IASR). We believe that the ISP is a critical document to assist policy managers and industry in understanding the challenging interaction of technology options required to achieve a cost effective, reliable and secure energy system for Australia.

As noted above, we have spent a considerable amount of time and effort preparing an independent assessment of CSP deployment costs within key Australian energy end-use markets. We would welcome the opportunity to provide AEMO with the full CSP cost model to allow for more accurate assessment of technology deployment costs.

Please don't hesitate to contact me if you require further information.

Yours Sincerely,

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