Monash University Response to 2022 ISP Draft Methodology

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Introduction

Monash University (Monash) is home to globally recognised researchers who are actively working in energy research. Monash has a strong track record in Smart Energy Systems, Energy Storage Materials, Energy Fuels (Hydrogen and Ammonia), and Energy Consumers. Monash holds a top 10 global ranking[1] in energy research for impact. Its efforts to accelerate the transition towards a Net Zero future are recognised globally through the United Nations Momentum for Change Award.

The Monash Energy Institute brings together approximately 200 world-leading researchers (excluding PhD candidates), industry partners and state of the art facilities to address important industry questions. Over the past ten years, Monash has built a strong capability in modelling the National Electricity Market. Some of this research is directly related to the issues that AEMO is addressing in formulating the Methodology for future Integrated Resource Plans (ISP).

Optimisation of Generation and Transmission Planning

The AEMO Draft Methodology clarifies the analytical challenges that AEMO must address in co-optimising generation planning, operations and large scale transmission investment, including the capacity for opening access to Renewable Energy Zones (REZ). The process outlined by AEMO with two levels of planning analysis and two for operational analysis:

- whole of outlook to 2050 (SSLT),
- a more detailed step by step optimisation (DLT), and
- detailed time sequential analysis for operational performance and dispatch (PLEXOS)
- transmission system performance to validate security and define power flow constraints for economic analysis.

This approach decomposes the problem into four time periods with less detail at the whole of period analysis and more detail as shorter time periods are considered. This method aims to best represent the dispatch of resources in the stochastic environment of the electricity market.

One important question is what level of accuracy is needed to represent generation unit commitment, dispatch and co-optimisation of energy and ancillary services for frequency and voltage control to properly assess the long-term value of generation and transmission resources. PhD candidate Ms Semini Wijekoon has recently completed her PhD thesis on this very matter.

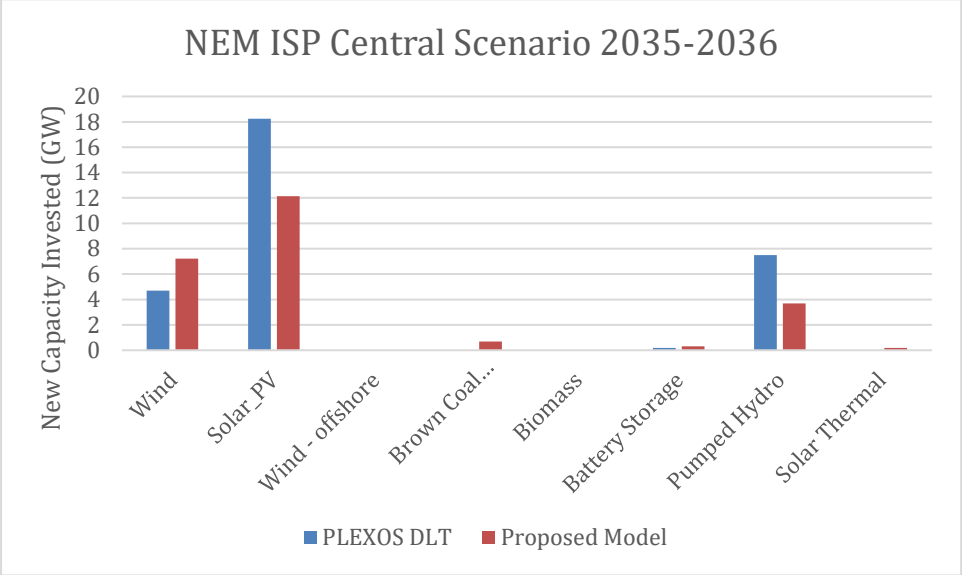
The project examined the impact of incorporating operational flexibility in the planning problem and its effect on the resulting investment solution. The project's primary focus was to develop solution methods for the NEM ISP to solve a planning model with a detailed operational model (with flexibility constraints) at a high resolution (sub-hourly) computationally more efficiently.
This was achieved by developing a comprehensive planning model with a detailed operational model (economic dispatch with ramping constraints) in Python and solving it using Gurobi. A mathematical decomposition technique named Benders decomposition was applied to reduce the computational burden, which solves the problem in parts iteratively and provides the optimal solution to the overall problem, instead of solving one big LP or MIP problem. With decomposition, a planning problem of a 1-year horizon at sub-hourly resolution was able to be solved in just 5 hours on average on a 16-core machine with 64 GB RAM.

[1] Times Higher Education Impact Ranking for SDG 7

The work used the scenarios and data published by AEMO for the ISP 2020, and the planning year 2035-2036 assuming that no new investments are made until 2035 excluding what's already committed.

The analysis showed that when high resolution is considered, the system utilises wind generation better. Refer to Figure 1 for a comparison of the new method versus the PLEXOS DLT equivalent. Thus, the developed planning model invests more in wind-based generators and less in solar-based generators in comparison to the solutions provided by PLEXOS ISP model for the same settings (8 load blocks a day for the same one-year period). This also results in comparatively lower investments in pumped hydro, as the need to store middle-of the day solar generation to satisfy the peak demand in evening is reduced.

Figure 1 Comparison of investments for 2035/36 single year optimisation versus PLEXOS DLT



The analysis also shows that, when the ramping constraints are ignored the system tends to build more wind since the thermal system appears more flexible thus can deal with the output variations of the wind generation.

The model also tends to underestimate the operational costs and carbon emissions, as additional generation due to ramping requirements are not into taken into consideration. Such a model also tends to build less pumped hydro as most of the flexibility requirements are satisfied by the thermal generators that appear to be more flexible than their actual capabilities.

Fortunately, the differences in these values are not significant, and the total cost values and new investment capacities are comparable with the ISP outcome. These results indicate that given the input scenarios and data, the PLEXOS DLT model is capable of capturing the required new investments reasonably accurately. However, considering higher resolution with detailed flexibility requirements at least in critical durations could provide overall benefits to the system including cost-effectiveness and reliability.

Impact of Market Uncertainties

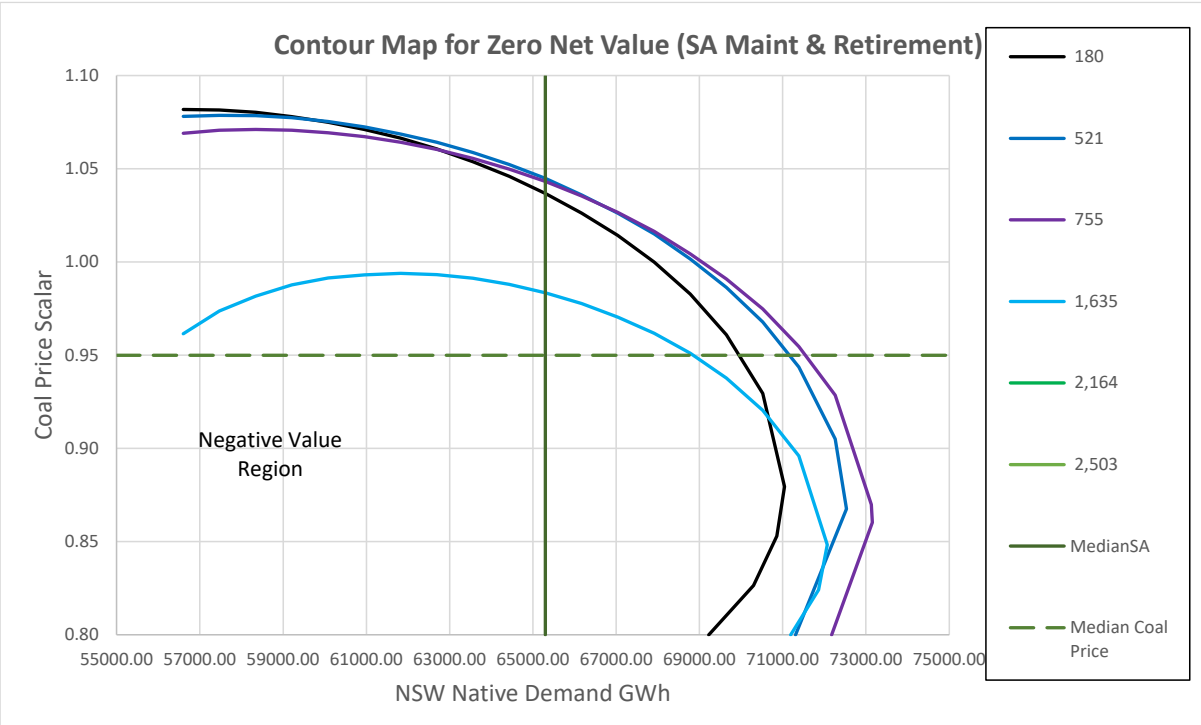
Initially funded by Ausnet Services in 2017, Dr Ross Gawler, Senior Research Fellow in the Faculty of Information Technology has been examining the nature of the optimisation of generation for various transmission upgrades in the NEM using an updated model of the 2018 ISP DLT Model as published by AEMO. This PLEXOS model has been progressively updated by Monash University to follow the revisions to ISP data published by AEMO. This work has examined a combination of annual optimisations based on the base resources for a specific financial year 2035/36. A total of 23 market factors have been randomised within the range of the five AEMO Scenarios up to 2050 to create a set of 80 randomised samples of these market factors. The various factors are suitably correlated according to the combinations used to define the five key scenarios. The 80 cases have been run using PLEXOS for one year with various combinations of transmission upgrades and analysed using regression techniques to better understand the value of specific investments, such as Kerang Link, Marinus Link Stage 1 and Energy Connect.

The analysis started with single year optimisations to screen out the generation and network options which are unlikely to be competitive for a long-term scenario. This is consistent with AEMO's option screening. It has been found that some 70% of generation options can be removed for long-term multi-year analysis which substantially reduces the size of the optimisation problem and allows more detail to be included in the representation of load, renewables and dispatch. Fortunately the annual simulations can be conducted with all options available without excessive run time. This assists the screening process and also facilitates the randomised sampling of market uncertainties.

The analysis is useful in readily identifying the important market factors that would undermine an investment and the ranges within which an investment's aggregate economic annual value might come close to or be less than its annualised cost. In some cases an ellipsoid function gives a good approximation to separating the combinations of market factors which support an investment and those which do not. This allows the energy planner to identify what kinds of changes in the market outlook should be monitored as a potential threat to a future investment. Such a method would allow AEMO to identify critical market issues that could undermine investment and may need additional attention to confirm suitable values for future ISP reviews.

For example, Figure 2 shows a set of contours for three important factors affecting the value of Kerang Link. The three most important factors were assessed as coal price (scaled from 2020 values), NSW native demand (excluding the effects of solar PV, electric vehicles and consumer batteries) and the amount of retirement of power plant in South Australia. The figure shows for various levels of thermal plant closure or long-term maintenance (MW) what combinations of the other two factors would result in zero economic value for Kerang Link. Negative economic value lies within the curved regions. Low coal price and lower NSW native demand undermines the value of Kerang Link. All other market uncertainties were set to their medium state over the range of uncertainty. The medians for coal price and NSW native demand are shown on the chart.

Figure 2 Contours of market uncertainties affecting the value of Kerang Link



The work had also sought to see if a value function could be derived from the 80 randomised cases to approximate the value of a decision as derived from a multi-year stepped analysis such as is applied in the DLT analysis. If so, such functions could be used to replace traditional sensitivity analysis and to facilitate market risk analysis by allowing a model of market uncertainty to be used to quantify economic risk probabilistically without running dozens of DLT scenarios which would otherwise be required. Quantifying the risk of these investments in such complex markets is quite difficult because of the large number of uncertainties, the complexity of the market optimisation models and the lack of clarity about which uncertainties are dominant in affecting economic value.

Figure 3 shows the annual value of Energy Connect derived using the DLT model for the Central Scenario. The solid black line shows the value of Energy Connect from a multi-year solution in four-yearly steps derived using PLEXOS based on studies with and without Energy Connect. The dotted black line shows the value from single year solutions assuming an optimal plan could be developed separately for each year. The coloured lines show various regression models derived from the 80 samples run for year 2033/34. Several of the second order and non-linear functions of the market uncertainties give similar results to a linear regression function but they do not adequately replicate the value of Energy Connect obtained by the multi-year solution. They under-estimate value prior to 2031/23 and over-estimate value thereafter. Further analysis is needed to understand what determines these differences and whether the method can be further refined to better replicate the multi-year optimisation result.

More work is needed to adapt this method to better approximate what would be achieved through traditional sensitivity analysis taking one variable at a time. If more analytical work could be done at the annual or seasonal level, then much more detail of the load and variable resources could be included in the modelling and less iteration with detailed models would be achievable.

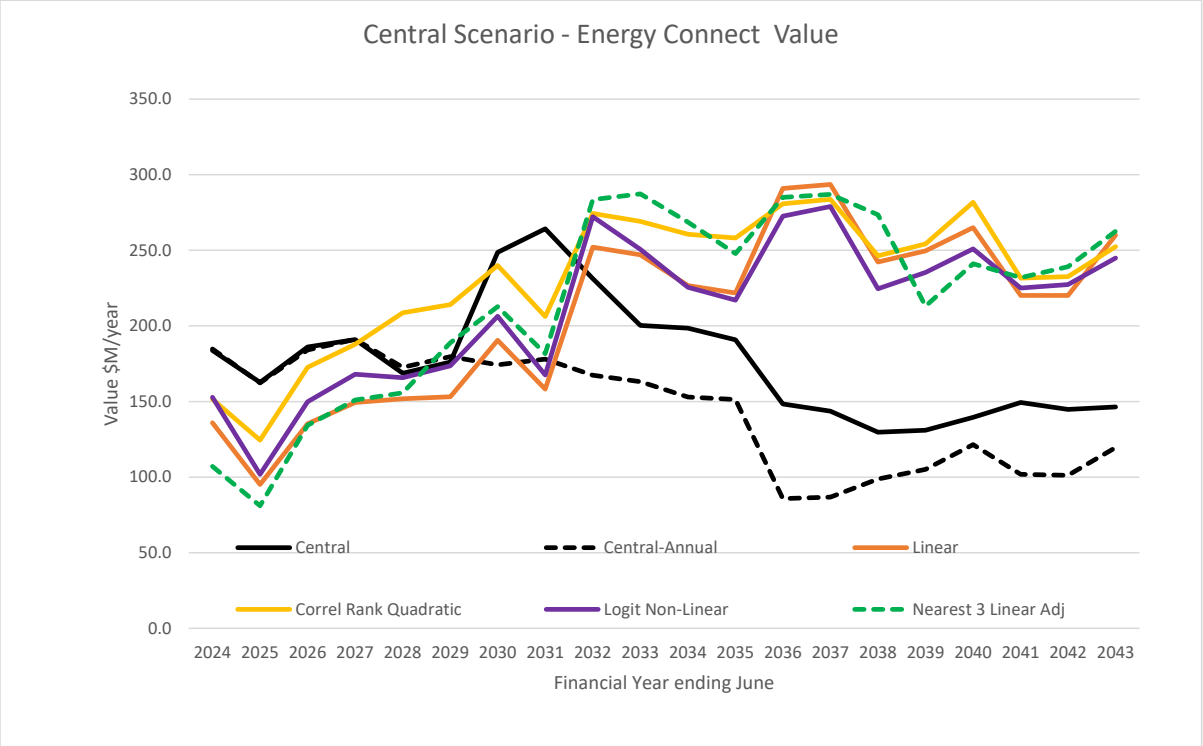



Figure 3 Value of Energy Connect – Central Scenario