Wind, water and wires: evaluating joint wind and interconnector capacity expansions in hydro-rich regions

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Renewable electricity will be decisive for decarbonising electricity in non-nuclear countries. Integrating variable or intermittent renewables like wind or solar PV creates challenges for managing system security, capacity adequacy, and modelling system needs. Peak to average outputs range from 3 or 4:1 for wind to 4-10:1 for PV. High penetration risks spilling a large surplus unless it can be stored or exported to regions with non-coincident renewable output. Battery electric storage typically buffers for 0.5-4 hours at considerable capital cost, pumped hydro storage can buffer from 8-24 hours at even higher capital cost (and with limited future potential). Building interconnectors to sufficiently non-correlated regions is similarly expensive. In all three cases modelling the system requires detailed hour-by-hour modelling, accounting for the state of storage and/or capacity to inject/export.

The one case where intermittency is unimportant and modelling the impact of high wind/PV penetration becomes dramatically simpler is where the country or region has an abundance of storage hydro-electricity and good renewables resources. To put the storage capacity of hydro into perspective, globally it offers 2,700 times global pumped storage capacity, which in turn has nearly 200 times as much capacity as battery electrical storage. This paper shows how a wind and hydro-rich region or country can efficiently manage renewable intermittency and offer decarbonisation benefits to its neighbours by investing in both wind and interconnection capacity.

There has been considerable interest in whether Tasmania (an Australian state) should invest massively in both wind and interconnection to the state of Victoria. However, Tasmania's *Battery of the Nation project* has been strongly criticized as an expensive way of providing unnecessarily long-duration storage when cheaper mainland batteries could meet local requirements at much lower cost. Norway's rich hydro resources have similarly been termed a "Battery for Europe", again with some dissent. The argument here is not that hydro-rich regions can displace "batteries" located in their neighbours, but that their hydro resources allow them to provide *local* storage to allow massively expanded intermittent renewables capacity, provided they can export the resulting surplus and reduce CO_2 emissions in the neighbour. This paper demonstrates how this may be achieved and how to quantify the costs and benefits of so doing.

The key to the simplification is that stored water in the dams sets a uniform price of water even with complex hydrology and many different dams, as at any moment the hydro generation can be sourced optimally and water values equated (assuming, as is common, that the system is energy, not instantaneous capacity constrained). Given adequate export capacity, intermittency is no longer a problem, so that the main determinant of equilibrium volumes and prices is annual wind and hydro production, avoiding most of the need for hourly simulation of flows into and out of storage. This paper uses a simple spreadsheet model that can give a quick estimate of the impacts of investments in wind and interconnector capacity. It illustrates the considerable simplification this combination of wind and water can provide to understanding system behaviour, in contrast to the rather black box nature of more sophisticated modelling. It offers transparency for an otherwise rather complex system in which uncontrolled variability normally poses considerable modelling challenges.

The Tasmanian case is also instructive as its proposed investments would have to overcome a variety of obstacles if it were to rely solely on liberalised market incentives. The viability of investing in more wind depends on the ability to export that wind, while the profit of the proposed interconnector depends on investing in more wind and lowering local prices. Both depend on receiving adequate reward for the carbon displaced on the mainland and any increased mainland consumer benefits from lower prices, which in turn depend on efficient pricing in the wholesale market and for transmission. These are not inconsiderable obstacles, compounded by ownership fragmentation, multiple jurisdictions, and extensive market power. Both investments will either need long-term contracts or state underwriting/ownership to overcome these obstacles in Australia. This paper shows how to estimate these co-benefits in a simple spreadsheet model that determines the overall benefits and their distribution between various parties to provide guidance on how beneficiaries might collectively finance the investments.

To argue for the relevance of this paper, a surprising number of countries (36) provided more than half their generation from hydroelectricity in 2015. In Europe, Norway, Iceland, Austria and Switzerland have more than half their generation from hydro, while eight countries in Latin America have more than 60% hydro, of which the largest are Brazil, Paraguay, Colombia and Venezuela. Some of these countries are connected to neighbours with lower or little hydro resources. Others (China, Canada and the US) have massive hydroelectric capacity where the issue is investing in more domestic interconnection.

Tasmania offers a good example of an isolated region rich in storage hydro and wind resource (capable of meeting all domestic demands) connected to Victoria via the 500 MW DC Basslink. Victoria is heavily dependent on brown coal for generation and with poorer wind resources. The average carbon intensity of generation in Victoria in 2018-19 was 0.89 tonnes CO_2/MWh. As Tasmania can (with modest additional investment) generate entirely carbon-free electricity, an extra MWh of exported wind could displace this volume of CO_2. In 2018 the average capacity factor for three main wind sites in Tasmania was 38% while for two in Victoria it was 28%. The Australian Government is considering a new interconnector project, Marinus, two 750 MW subsea DC links to Victoria.

Total net exports from Tasmania are pre-determined by total supply less demand: X – M = W + H – D, where X is exports, M is imports, W is wind, H is hydro and D demand, all per year. Thus if Tasmania installs additional wind (or solar PV) to increase annual wind output by 1 GWh, it could displace 890 tonnes CO_2. In the brief period that Australia has a CO_2 tax, in 2012 its level was $A23/tonne. By September 2021 the EU ETS price was around €60/tonne ($A94/tonne), within the Paris target-consistent range. At this latter figure, 1 GWh of extra exported Tasmanian wind would deliver carbon benefits of $A83,000/GWh, at least until coal is phased out or is no longer at the margin. Crucially and quite generally, as wind and hydro output are exogenously determined (by weather), their carbon credit is just driven by W + H – D and hence independent of market conditions.

The model set out in the paper identifies the benefits to hydro revenues, carbon savings, interconnector and wind profits, as well as consumer impacts in both countries, and impacts on Victorian generation. The model illustrates the problem of allocating the benefits to ensure efficient and coordinated investment in interconnection and wind capacity and suggests solutions to lower the cost of finance to ensure least cost delivery. The very rough cost-benefit analysis suggests that the projects are indeed socially valuable with an adequate value (or price) assigned to carbon, but that they are unlikely to take place on a merchant basis given the numerous market failures present in the Australian National Electricity Market.

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