The Effect of Renewable Electricity Generation on the Value of Cross-border Interconnection

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Abstract

Connecting two electrical grids allows power to be traded between the areas, which can improve reliability and lower electricity prices. Over the coming years, electrical networks will have to adapt to larger amounts of intermittent renewable generation. Here we use hourly data from 155 world-wide geographic regions to investigate how the value of connecting electrical grids changes as renewable generation is incorporated. We show across five continents that significantly more interconnections are cost effective in a 100% renewables scenario, and that the investment savings they result in can be 100 times higher. Furthermore, we show that many interconnections that are profitable with dispatchable generation are not profitable in a renewable generation scenario. Finally, we show that in many cases the interconnection only reduces the investments costs of one of the two regions – with the larger electricity market, in general, seeing a greater cost reduction.

Keywords: Cost optimization, Global supergrid, High-voltage direct current, Renewable electricity

1. Introduction

In order to maintain a consistent and reliable supply of electricity, there must be a continual balance between the electrical supply and demand on a network. Human behavior drives a region's electricity demand, with weather and social variables strongly contributing to peak demand's size and timing [1]. Meeting peak demand can be expensive – requiring dispatching generation that is very rarely used or discharging stored energy.

High voltage direct current (HVDC) interconnections can be used to form electrical connections between two independent electricity grids, allowing power to be traded between the regions, without coupling their grid frequencies. As seasonal, cultural, and weather patterns may vary significantly, imported surplus power from a neighbouring region could be used to meet peak demand at a lower system cost [2, 3].

Historically, analysis supporting the undertaking of new HVDC projects is done on a case-by-case basis, using the respective generation portfolios to assess the value that the interconnection would provide (e.g. [4]). While some formulations for optimal HVDC expansions have been proposed, these have been based on the network architecture [5], markets [6], and basic models for demand [7, 8, 9]. In reality, the utility of a potential interconnection is strongly related to the electricity demand in the two regions; in order to utilize an interconnection, one region must have surplus power at the same time as the other has a power deficit. Therefore, without modelling the respective demand and supply at a relatively small time resolution, it is difficult to assess the value that a potential interconnection would provide.

To align with decarbonization objectives, increasing amounts of solar and wind power are being installed, meaning power systems must adapt to running from variable generation sources [10].

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There is not consensus on the power system design that would best support a large penetration of variable renewables [11], but it is expected that there will be increased requirements for energy storage [12] and power imports and exports [13]. In many cases, areas with plentiful natural energy resources are located in areas with little or no demand for electricity. The variation in the quality of natural resources has led to suggestions to create a 'supergrid' that spans across whole continents, connecting demand to faraway renewable resources [14]. A potential globe-spanning grid was proposed in [15], alongside a pathway to development. While a global supergrid might be an effective solution in the future, there are regulatory [16] and technical [17] barriers which must first be solved. Given that they are already in use, HVDC interconnections between two independent networks provide a more realistic and cost effective solution in the shorter term [18]. There has been growing interest in adding HVDC links to increase domestic renewable consumption, such as the planned link from Singapore to Australia [19].

Some previous studies have investigated the use of interconnections in easing the transition to renewable energy. For example, it has been shown that the volatility of wind power can be reduced by connecting areas with uncorrelated wind power [20]. There have also been several studies considering the extend to additional interconnection would reduce costs in the renewable transition in the UK [21], France [22], Europe [23, 24], the US [25], and Northwestern China [26]. However, for determining the value of interconnections in the global energy transition, single systems should not be considered in isolation.

This paper uses historical hourly electricity demand from 155 power systems, spanning five continents, to quantify the value of adding HVDC interconnections between the areas. Using hourly time series from the year of 2019 (the most recent non-pandemic year) allows the interactions between neighbouring areas' demand to be captured, simulating precisely when the interconnection will be usable. By combining the hourly demand data with hourly solar and wind data, we are able to evaluate the change in the value of interconnection once renewable generation is incorporated. In each case, an iterative technique is used to determine the globe-wide interconnections which add value.

Therefore, the contributions of this paper can be summarised as follows. First, that we use historic hourly electricity and weather data to investigate the use of interconnection between 155 regions across five continents. This represents a significant extension from the literature, which only consider a single specific system (e.g [27]) or use synthetic models for electricity demand (e.g. [23]). The analysis in [3] includes 14 globe spanning regions, using a mix of historic and synthetic data. Whereas, this paper considers many more, and smaller geographic regions and using purely hourly data. Our extended dataset allows more than 500 times the number of potential interconnections to be considered compared to [3] – and of a wider variety of lengths. Second, that we investigate the change in value of interconnection between a renewable generation scenario and the current fuel mix. The previous literature discussed mainly considers various renewable generation scenarios (e.g. [28]). The change in value is important because HVDC interconnections take many years to build, so it may be necessary to start building some that are not profitable under the current fuel mix. Third, that we investigate how the value provided by the interconnections would likely be split between the two areas. This builds on previous analysis, which only considers the total value (e.g. [27]) or the value to one of the systems (e.g. [22]). This is important because it has implications for how financing of the project should be split between regions. Finally, that we include in the renewable generation scenario the mix of solar and wind power that would best meet each regions' demand. This is distinct from the literature, which mostly include fixed ratios of the renewables (e.g. [29]) or extrapolate based on the current mix (e.g. [9]). This choice makes the modelling more complicated, but we believe that it results in a more realistic high renewables scenario. In order to ensure our conclusions are robust to our modelling choices, we include a robust sensitivity analysis.

The remainder of this paper is structured as follows. In Section 2 we describe the methods used to gather electricity demand, model renewable energy, and calculate the cost of potential interconnections and energy storage requirements. In section 3 we present some static analysis of the consider geographic regions. Section 4 presents the optimal interconnection results in conventional and renewable generation scenarios. The importance of various assumptions on our results are explored in Section 5, and Section 6 concludes the paper.

2. Methods

In order to analyze the value of interconnection between two regions with both renewable and non-renewable generation, a variety of data and modelling is required. In this section we detail the data, processing, and modelling used in this study.

2.1. Electricity Demand

Electricity demand is fundamental to the need for system interconnection. In order for an interconnection to be valuable, one area has to have a surplus of electricity at the time when the other has a shortfall. The occurrence of these events is a function of both the generator availability and the electricity demand in the regions.

Therefore, it is important to have granular models for the electricity demand in both regions, as electricity demand varies significantly throughout the day. In this paper we use historical hourly real data for electricity demand. The disadvantage of this is that we cannot take into account future anticipated changes to the electricity demand profile. Although there are some future electricity demand models available, these largely only give example days and would not capture the relationships between different regions' demand. In reality there are many complex factors which affect an areas' electricity demand. Some factors will be common or similar between neighboring systems, such as season, weather, or international events. However, some may only affect one of the systems, such as cultural holidays, local events, or working styles. Therefore, for the purposes of analyzing the interaction between different electricity demand profiles, we feel that using historical data has the most merit. We operate on the assumption that a relatively small percentage of the global electricity demand in 2019 is flexible; electric cars and smart thermostats are in early stage deployment and industrial demand flexibility will not be possible in many of the countries we consider. Therefore, when you consider changes to the load profile, we expect new loads to come online, but for many of these to have some inherent flexibility. Therefore, the analysis in this paper can be considered a baseline for the system before any additional 'smart' loads are added.

Hourly electricity demand for the year of 2019 was collected from the sources listed in Table 2. This year was chosen as the most recent non-pandemic year. Most of the data was gathered from transmission system operators and electricity market contractors. Unfortunately, in some regions data could not be found; either because it is not publicly available or because the authors were unable to locate it. In order to analyze interconnection potential, all data was converted into the UTC timezone.

In the cases of India and China exact hourly data was not available, but daily maximum and minimum loads were given alongside typical load profiles (also, for India, daily energy consumption). These were used to estimate the hourly electricity demand, by scaling the typical daily profile to the required maximum and minimum and then applying a smoothing filter on the intersection between days[1].

2.2. Renewable Generation

To understand how renewables will impact the value of HVDC interconnection, we need to model how the potential generation interacts with the systems' respective demand profiles. There is a complex relationship between demand and renewables' output, because demand is driven to some

[1] The processed electricity demand data will be published alongside this article, so that it may be used in further analysis.

extent by weather. Using historical data would allow an exact relationship between demand and generation to be captured. However, it is difficult to use historical solar and wind generation data for several reasons. Firstly, the capacity of renewable generation is constantly increasing (especially in the case of distributed generation) so the output figures would trend up over time. Second, that some of the considered systems do not have a significant renewable generation portfolio yet, so this would limit the regions to be analyzed. Instead, we use historical wind speed and solar irradiance data, which is related to the output that solar or wind power would achieve.

Here we estimate renewable generation outputs based on hourly wind speed and solar irradiance data available in [30]. The hourly data is available world-wide at a grid spacing of $0.5^o \times 0.625^o$ degrees latitude and longitude. The data is inferred based on satellite observations, and is available hourly back to 1980. It should be noted that analysis has shown that ground-level solar irradiance may be systematically overestimated in this dataset [31]. However, for this analysis, it is the relative change in solar output that is important, rather than the absolute values. Additionally, this data established in works investigating future solar and wind power output, such as [32, 33, 34, 35].

Solar irradiance and wind speed drive solar and wind generation. In the case of solar, output is approximately linearly related to solar irradiance [36], therefore those values can be left unchanged. However, there is a nonlinear relationship between wind speed and wind power output. Here, we assume a typical wind turbine power curve, with a cut-in speed of 2.5 m/s, a rated speed of 14 m/s and a cut-out speed of 25 m/s; within the cut-in and rated speeds the wind power grows with the cube of wind speed, after which it remains constant until the cut-out [37].

These models will not output direct predictions for power output in units of Watts. However, to understand the relationship between renewable generation and demand, values linearly related to output are sufficient. In other words, although more precise renewable generation models are available, none is required as we are only concerned with relative changes of the solar and wind power, meaning absolute scaled values are not necessary.

2.3. Interconnection

To compare the cost effectiveness of HVDC in different scenarios, an estimate for the cost of building a new interconnection is required. The investment costs depend on the length and size of the connection, as well as whether it is overhead, underground, or underwater.

Here, we use the model proposed in [38], which gives the total cost of a single branch, two node cable as:

$$\begin{aligned} c_{int}(p, \hat{l}) = & 2N_0 + 2N_p\, p + B_0 + B_l\, \hat{l} \\ & + B_{lp}\, p\hat{l} + S_0 + S_p p\,, \end{aligned} \tag{1}$$

where p is the rating of the interconnection, $\hat{l}$ is the effective length and the remains are coefficients whose values are given in Table 1. The effective length is the weighted sum of the cable lengths through different medium, such that:

$$\hat{l} = l_{uw} + \frac{5}{4} l_{ug} + \frac{2}{3} l_{oh}\,, \tag{2}$$

where l_{uw}, l_{ug}, and l_{oh} are the underwater, underground, and overhead lengths respectively.

Parameter	Value	Unit
N_0	2.75×10^7	\$
N_p	1.322×10^8	\$/GW
B_0	4.25×10^6	\$
B_l	3.16×10^5	\$/km
B_{lp}	1.15×10^6	\$/GW-km
S_0	6.71×10^7	\$
S_p	8.464×10^8	\$/GW

Table 1: Parameters for the interconnection cost model. Costs have been converted from Euros to USD using the exchange rate from 2018 (the year the model was published).

The length of a potential interconnection is calculated by finding the shortest point between the edges of the two regions. The interconnection is assumed to lie along this path, with the land section being underground and the water second being underwater. These land and water distances were calculated using the *basemap* software package alongside shape files of the regions. In reality, this may not be the cheapest combination of land and sea, and it may not be possible to lay a HVDC line along this path. However, given the scale of the connections considered and the scope of this study, this was assumed to be sufficient for this application.

The interconnection between two countries is assumed to transmit power whenever one region is in a surplus and the other is in a deficit of power. The amount of power transferred is equal to the minimum of the available power and the demand still to be met. Interconnections are assumed to be used before any energy storage is deployed.

2.4. Energy storage

An alternative to interconnection for solving discrepancies between supply and demand is energy storage. Energy storage technologies, such as Li-Ion batteries, can be charged at times of surplus and discharged at times of shortfall. In order to test the extent to which interconnection is a cost-effective alternative to interconnection, a model for the cost of energy storage is required. When considering the cost trade-offs between interconnection and storage what matters is the storage medium that the interconnection would be replacing. There are a large variety of energy storage options, which are suited to storing energy over different time periods; short-term energy storage such as Li-Ion batteries are suited for frequent charging and discharging, while long-term energy storage such as Hydrogen is suited for storing energy for long periods and discharging for rare low renewables events [39]. It is challenging to consider sizing of a system with multiple modes of energy storage, because one must consider operation over multiple timescales [40]. Therefore, here we focus on only Li-Ion batteries as an energy storage technology, and we consider only the capital cost of the storage, which is directly comparable to the interconnection costs defined above. We chose to focus on Li-Ion because our operational assumptions assume that the interconnection will be used for routine operation (they are used before energy storage), and so it would be likely that the interconnection would largely replace short duration storage. However, a more detailed analysis is required to understand the interactions between additional transmission and long-duration storage, and this is left as further work.

The energy storage requirements are estimated by integration of the net demand, which results in a profile of the available energy with time. This time-series is then translated such that the stored energy is always positive, and the peak of the resulting profile determines the required storage capacity in MWh. This calculation occurs after the available interconnection has been deployed as described above.

The cost of the battery storage is assumed to be linear with installed capacity, at 210 /kWh, which is the mid level estimate for 2030 in [41]. Given the timescales required to install new HVDC projects, the 2030 cost was assumed to be a reasonable comparison point.

2.5. System Sizing

In order to understand the value of interconnection we need estimates for the renewable generation and energy storage portfolio of each region. In this section we describe a process for determining the minimum cost combination of wind, solar, and energy storage, to meet demand. We therefore consider the following function f which determines the total capital cost (in \$m) of the system:

$$f(W_{cap}, S_{cap}, E_{cap}) = 1.1\ W_{cap} + 0.77\ S_{cap} + 0.21\ E_{cap}\,, \tag{3}$$

where W_{cap} is the total installed capacity of wind power, S_{cap} is the installed solar capacity, and E_{cap} is the total energy storage capacity. We use the 2030 energy storage cost from the previous section, and to remain consistent we use mid-level estimates of 2030 costs per MW of both wind [42] and solar [43].

The sizing problem is then to minimize the function f subject to a set of constraints which ensures that demand is met. First we consider the system balancing at timestep t, so we enforce:

$$p_t = W_{cap} w_t + S_{cap} s_t + d_t - c_t - \sigma_t \quad \forall t\,, \qquad (4)$$

where p_t is the power demand at time t, w_t is the percentage of nameplate wind capacity available, s_t is percentage of nameplate solar, d_t is the grid-side discharge of the storage, c_t is the grid-side charging of storage, and σ_t is a slack variable allowing for curtailment of renewables. All variables are constrained to be greater than zero, such that:

$$\begin{aligned} W_{cap}, S_{cap}, E_{cap} \geq& 0 & (5)\\ d_t, c_t, \sigma_t \geq& 0 \quad \forall t & (6) \end{aligned}$$

Values for p_t, w_t, s_t are parameters, so (4) is a linear function of the decision variables W_{cap}, S_{cap}, d_t, c_t, σ_t. It is necessary to ensure that the state of charge of the storage remains below the total capacity. Without fixing the initial state of charge, we can enforce this by ensuring that the net energy discharged or charged to the storage is never greater than the capacity. This can be written as:

$$-E_{cap} \leq \sum_{\tau=0}^{t} \big(\frac{1}{\mu} d_\tau - \eta c_\tau\big) \leq E_{cap} \quad \forall t\,, \qquad (7)$$

where the subscript τ is used to sum all the timesteps up to and including t, and η is the charging and discharging efficiency of the storage. Note that the SOC equations assume that the timesteps are of length 1hr, if the formulation is used for different time resolutions then a weighting factor must be applied to the charging and discharging elements. Additionally, here we assumed that storage had the same charging and discharging efficiency (as is common for Li-Ion batteries), however different coefficients can be used if this is not the case. Finally we enforce that the total energy generated is greater than the total demand. This serves two purposes. Firstly, it prevents the storage being used as 'virtual generation' (a mathematical issue where the initial SOC of the battery is effectively used as an energy source). Secondly, we believe there is a political reluctance for countries to explicitly rely on power imports (rather than this just being economical). If one would want to remove this assumption, they would need to add one to ensure that the total energy charged into storage is greater than the total discharge, to solve the first issue. This can be written as:

$$W_{cap} \sum_{t}^{T} w_t + S_{cap} \sum_{t}^{T} s_t \geq \sum_{t}^{T} p_t\,. \qquad (8)$$

where T is the total number of timesteps being considered. Therefore the problem of sizing a single region's wind, solar, and energy storage portfolio can be described as:

$$\begin{aligned} \min_{W_{cap}, S_{cap}, E_{cap}, c, d, \sigma} \quad & (3) \\ \text{s.t.} \quad & (4),(5),(6),(7),(8)\,. \end{aligned} \qquad (9)$$

This takes the form of a linear programming problem, with $3T+3$ variables, T equality constraints, and $5T + 4$ inequality constraints. We implemented this formulation using the CPLEX linear programming solver [44]. Given that the constraint matrices are fairly dense (many of the variables appear in each constraint), the solution time of the problem grows quickly with the number of timesteps. We found that using the full year of data, resulting in a problem with 26283 variables and 61324 constraints, was not computational tractable on a high performance personal workstation. Therefore, we performed sizing using eight weeks of data, comprised of four two week segments spread evenly through the year – two in January, two in April, two in July, and two in October. This means that the sizing takes into account both diurnal and seasonal variation, although there is no guarantee that this would achieve the same result as if the whole year could be included.

3. Analysis of considered areas

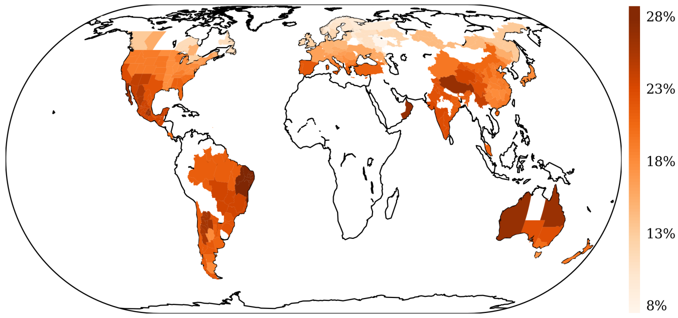
Here we consider 155 distinct geographic regions, for which hourly electricity demand data was available. The regions span five continents; unfortunately, the authors were unable to locate hourly demand data from any regions in Africa. The results shown in this analysis only display spatial variation in quantities; however an animation visualising electricity demand as a function of both space and time is available [45].

The value of interconnection in a predominately renewables scenario will depend not only on the region's electricity demand, but also on its renewable generation output. Here we focus on solar and wind power, which are intermittent and have seasonal patterns, as they are governed by weather. Due to varying climates, the cost effectiveness and reliability of solar and wind power will vary by area; for example, solar power typically has a better yield near the equator.

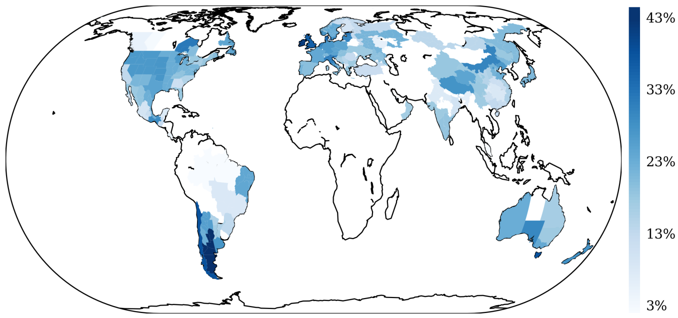
Regions with highly variable load and generation may see the greatest cost reduction by trading power with other systems, particularly those whose net demand (electricity demand minus renewable generation) is less variable than their own. Variability of demand and supply can be measured using the load factor, which is the ratio of the average value to the peak value (also called capacity factor when the peak value is the rated capacity). Considering the load factor over a whole year, low values typically demonstrate one or more of: a strong seasonal effect, a strong diurnal effect, or a high intermittency. Load factor can also be used to describe the variability of electricity demand, where high values may indicate a large share of industrial demand (which tends to be flatter throughout the day) or low seasonal variation in climate. Figure 1 shows the capacity factors of potential solar power and wind power, as well as load factors of electricity demand from 2019. The solar and wind power potential is estimated using the hourly solar irradiance and wind speed from the region, as described in the Methods section. These methods are established, as in [35, 46, 34] and we have validated our results against the open source tool developed by these authors.

The highest solar capacity factors are seen near the equator, while the highest wind load factors are seen in colder coastal areas. The highest demand load factors are seen in areas with more primitive access to domestic electricity, and/or with dominant manufacturing industries.

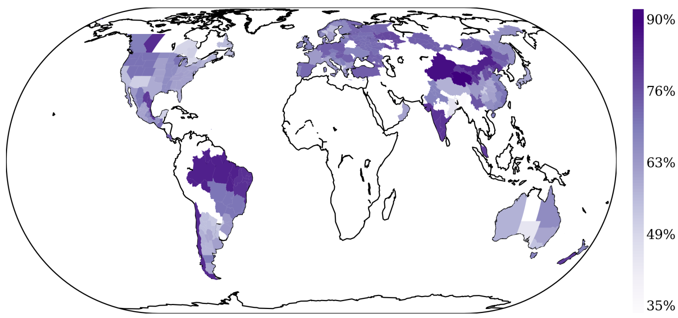
For each region the optimal system sizing (in terms of installed wind, solar, and battery storage) was determined using the optimization formulation defined in Section 2.5. Figure 2 shows the resulting systems, in terms of the ratio of solar and wind power (in terms of both nameplate capacity and energy) and the amount of generation supplied by the resources compared to the electricity demand. The latter is an indication of how the cost of the generation compares to the storage – if generation is very cheap per MWh (rather than price per MW which is the same for all regions) then have excess generation may be more cost effective than energy storage.



(a) Solar

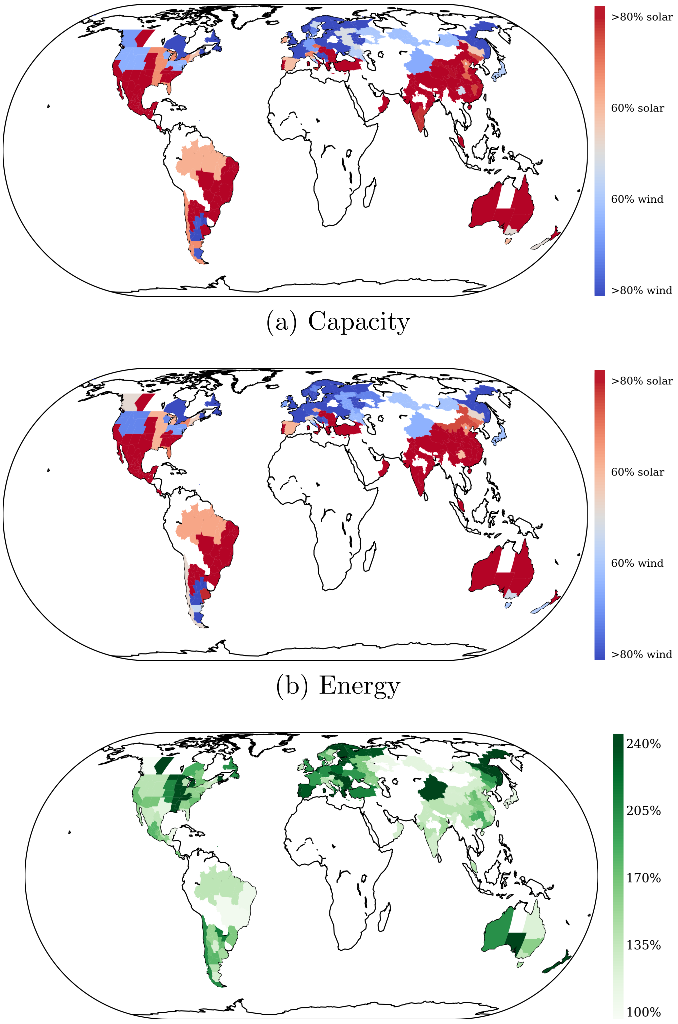


(b) Wind



(c) Electricity Demand

Figure 1: Potential capacity factors of solar and wind power, and load factor (ratio of average to peak value) for electricity demand. Values use the hourly time series from the year of 2019.



(a) Capacity

(b) Energy

(c) Oversupply

Figure 2: The cost optimal renewables mix: (a) The solar/wind breakdown by nameplate capacity, (b) the solar/wind breakdown by energy produced, (c) the amount of energy produced relative to the total demand.

The optimal generation mix varies significantly between areas, with (in general) coastal regions and those closer to the poles favoring wind power and inland regions nearer the equator favoring solar power. We can see an inverse relationship between the oversupply and the demand load factor (areas with high load factors choosing lower surpluses). This may be because for areas with larger seasonal variations larger amounts of energy storage are needed to achieve system balancing without excess generation.

Our results broadly align with those in [24], which considers optimization of solar, wind, hydro, and bioenergy for European countries. As well as different resources, they use a different year of data (2016) and a lower time resolution (four hours). However, for the majority of European countries they found wind power dominant over solar, especially in the Northwestern countries. Additionally, they found that for the most Southern European countries, such as Spain and Portugal, solar power was more dominant that wind power. The fact that they included some thermal generation, and limited energy storage meant that a more direct comparison was not possible. Similarly our results for Brazil are consistent with the analysis in [47], with both predicting around a ratio of 1:4 for wind:solar power.

4. Interconnection Results

Installing new HVDC interconnections is a potential alternative to energy storage, where the ability to trade power with another area results in a smaller requirement for stored energy. Here we consider, given the hourly electricity demand and land and sea distance between two areas, which new interconnections would be cost effective. The value of a new interconnection is estimated as the savings in cost of energy storage minus the cost of building the HVDC interconnection. It should be noted HVDC has further benefits compared to energy storage, such as a longer lifespan, less environmental impact to build, and better resiliency to component failure, which are not considered here.

We are particularly interested in understanding how the value of interconnection changes with renewables. Therefore, two scenarios are considered: a majority conventional generation scenario (analogous to current operation), and a renewable energy scenario.

In both cases there is assumed to be the surplus energy generation chosen in the optimization (and visualized in Figure 2c). For the conventional generation scenario there is assumed to be a flat rate of available power, and for renewable generation the the profile is taken from the wind/solar mix shown in Figure 2. In both cases there will likely be times where the power generation is insufficient to meet the power demand, which will be met with energy storage. Existing HVDC lines are assumed to be operational, and are used before the energy storage is deployed.

A simulation was then run using the 2019 wind speed, solar irradiance, and demand data assessing the energy storage requirements of each region. An analysis is then completed on each potential interconnection (in this case there are 155x154 potential connections) and they are assigned a value – in terms of the cost of energy storage they would save minus the cost of installation. Optimal interconnections are determined in an iterative process, where the globally highest value interconnection is found and then simulations are re-run assuming that interconnection has been installed. This process avoids choosing many similar interconnections, which would compete to provide the same benefit.

4.1. Majority conventional generation

Figure 3 shows the cost-effective HVDC interconnections in a majority conventional generation scenario. Each continent is shown separately for clarity. Valuable interconnections are shown with black markers at each terminal, and a line whose color dictates the combined savings provided to the regions. Gray shading denotes the areas for which data was available, meaning that interconnections to areas without shading have not been considered.

Here, as the same generation profile is used in each region, the value of additional interconnections is driven solely by differences between the electricity demand profiles. In most cases this difference is caused by one of: (1) a time difference (considering coordinated universal time) in the start and end of the working day, (2) different end-uses of electricity (e.g. whether the residential or industry load is more dominant, or whether the region has electrified heating and air-conditioning), or (3) a disparity in total electricity consumption. In all three of these cases, one region is more likely to have a lower demand at the other region's peak demand time.

There are a number of short connections which provide some value, as well as two intercontinental connections. In later sections we explore the factors that govern the installation of interconnections.

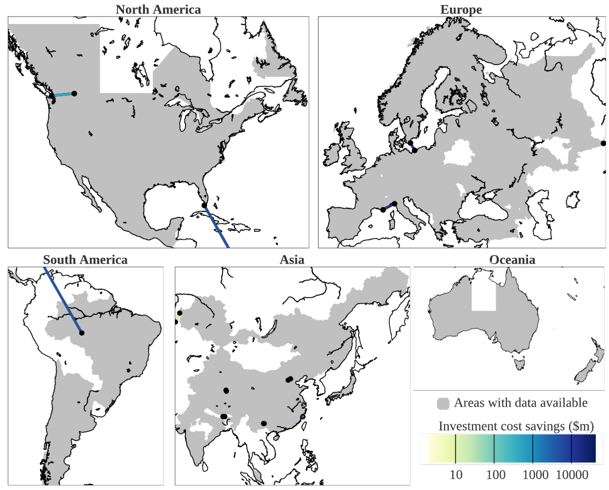


Figure 3: The HVDC links that would decrease investment costs in the conventional electricity generation scenario. The investment costs are defined as the price of the interconnection less the reduction in energy storage costs.

4.2. Renewable generation

Figure 4 shows the cost-effective HVDC interconnections if each region generates electricity from the mix of solar and wind power shown in Figure 2. The format and scaling remain the same as in the conventional generation maps.

In this case, there are significantly more interconnections that add value, of a variety of lengths. On average, the interconnections provide more value than in the conventional generation case, and the most valuable connections provided considerably higher savings (note that savings are displayed on a log scale). This may be because, in the renewables case, the climate difference between countries causes disparity in generation as well as demand, exacerbating the differences between area's generation requirements.

Many of the highest value interconnections are located in Asia, especially within China; whereas there are very few profitable Asian interconnections in the conventional generation scenario. This is likely because the wind speed and solar irradiance varies significantly across the country; Figure 1 shows that solar irradiance is comparatively

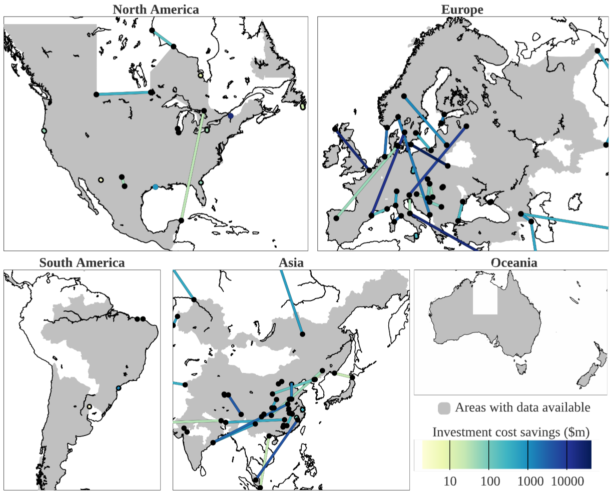


Figure 4: The HVDC links that would decrease investment costs in the renewable electricity generation scenario. The investment costs are defined as the price of the interconnection less the reduction in energy storage costs.

high in the south of the country while wind power is significantly higher in the west.

Another notable difference is the presence on intercontinental connections in the renewable generation scenario. Some of these connect Asia with Europe, meaning they are east-west connections. While some connect North and South America, which are north-south connections. Climate conditions vary significantly between north and south, while daylight hours vary along east-west. Therefore these intercontinental connections may be driven by solar generation, which is linked to daylight hours.

It is difficult to directly compare the individual interconnections chosen between the conventional and renewable generation scenarios visually. However, several of the interconnections chosen in the conventional generation scenario are not chosen in the renewable energy. For example, the Brazil-Chile connection in the conventional generation scenario but not in the renewables scenario. This suggests that the addition of renewable generation can cancel out some of the demand differences which made these interconnections profitable with conventional generation.

4.3. Division of Benefit

The previous analysis has considered only how the total benefit of connecting the two regions compares to the total cost. However, the benefit (in terms of the reduction in the required amount of energy storage) may not be evenly distributed between the two regions. Here we consider the value that interconnection provides to each of the two regions, assuming that each bears half of the interconnection costs and all the reduction to their energy storage requirements. In practice, an equitable division of the HVDC cost should be determined based on the share of benefit each region receives. This analysis is important because historically many interconnection projects are driven by a single region, who has scarce natural resources. Therefore, understanding how the benefit of the connection is split between the operating areas is important.

Figure 5 shows a grid where each cell represents a potential interconnection between two regions, described by the axes. The regions are grouped by continent, ordered from west to east within that grouping, and appear in the same order on both the horizontal and vertical axis. Whether a cell is colored dictates whether there is a benefit to the region on the vertical axis of connecting to the region on the horizontal axis. The color scheme shows whether the benefit occurs in both scenarios, only the conventional generation one, or only the renewable generation one. If all interconnections distributed value equally between the two regions, this chart would be symmetrical.

The value shown here is assuming no other new interconnection has been installed, whereas the optimal interconnections shown in Figures 3 and 4 used an iterative process to determine the valuable interconnections. Therefore, there are some which are shown to add value in this chart but do not feature in the map of valuable interconnections.

As expected, the majority of the valuable connections are between regions within the same continent, however some intercontinental connections have value in both scenarios. There is significant asymmetry in the chart; in many cases the value is

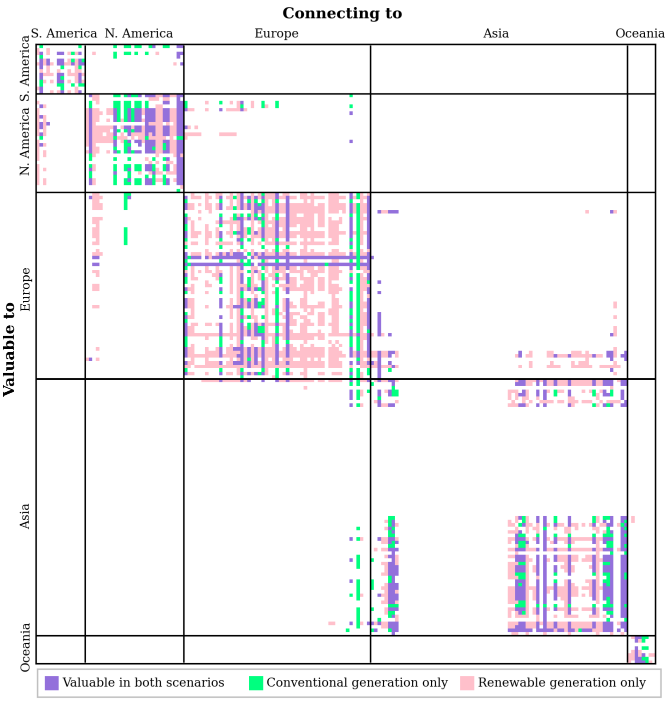


Figure 5: A grid showing how the value of each potential interconnection to each region changes between the conventional and renewable generation scenarios. Each cell represents the value of connecting the area on the vertical axis to the area on the horizontal axis. The shading of the cell demonstrates whether there is benefit in each scenario. Values assume that no other new interconnections have been installed. Note that along the axis the Russian regions are split between Europe and Asia, while Turkey (only one region available) is in Europe.

only seen by one of the two regions. For example, there is value to connecting most other regions in North America to those in the US, but only select value to the US regions. Also, there is value to the Russian regions for being connected to many European regions, but not the other way around. These can be seen by the vertical and horizontal blocks on the chart.

Although there are many connections that are valuable in both scenarios, some only added value in one of the two scenarios. This suggests that the addition of renewable electricity will radically change the differences between the net demand profiles, even in neighboring regions. It should also be noted that far more connections are profitable with renewable generation than conventional generation (as the previous results showed).

Figure 6 demonstrates some of the variables that may lead to unequal division of benefit of the interconnection between the two areas. The scatter plots show the value of an interconnection to an area against the difference in: (a) renewables mix, (b) oversupply of generation, (c) latitude, and (d) electricity market size (total electricity demand per year), (b) time zone, and (c) distance from the equator.

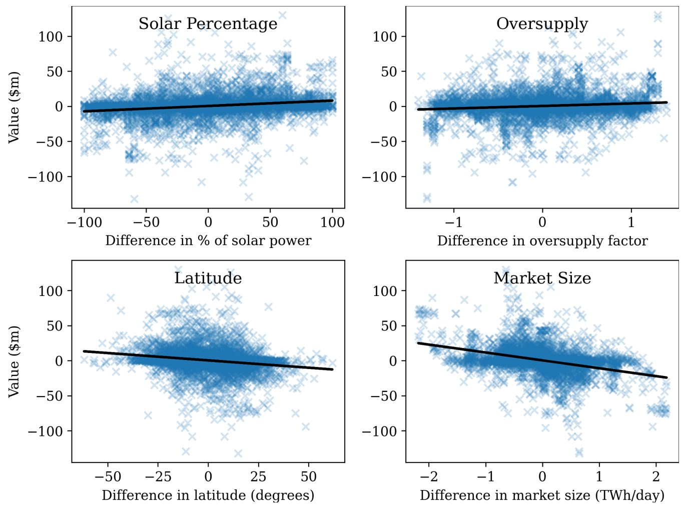


Figure 6: Scatter plots showing the value of an interconnection to a region against various parameter, with best fit lines shown in black.

The strongest relationship shown is between the value of interconnection and the difference in the areas' electricity market sizes; in both the conventional and renewable generation scenarios connecting to areas with smaller electricity markets tended to be more valuable. In other words, the area with a larger total electricity demand tended to receive a disproportionate amount of the value. This may be because the larger area has a higher absolute requirement for energy storage, and may therefore achieve a greater reduction in energy storage through the interconnection.

There are also slight trends for renewables and latitude. Connecting to an area with more solar power than you is, on average, more beneficial. Additionally, connecting to areas of smaller latitude is on average more beneficial. Given that the vast majority of the regions considered are in the Northern hemisphere, this may be explained by connecting to regions closer to the equator (which have stronger and more consistent solar resources). These trends are likely related; that areas which rely more on wind power benefit from connecting to areas with stronger and larger solar supplies. This may be driven by occasional low wind periods, where wind output is very low for several days; while the variation of solar power throughout the year is more predictable.

5. Sensitivity to Assumptions

This section explores how alterations to the set of assumptions we used in this analysis could change the results.

5.1. Storage costs

The price of Li-Ion batteries has fallen significantly over the past decade, consistently surpassing the cost reduction projections. Therefore, it is reasonable that the 2030 projected storage cost used in this analysis may be subject to significant uncertainty. In this section we considered how changing cost of storage would change the analysis.

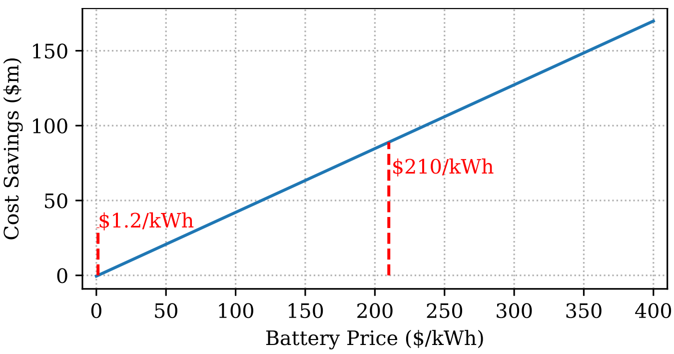


Figure 7: The value of the most profitable interconnections, varied by price of battery storage. Marked are the originally assumed price, and the price at which the interconnection is no longer valuable.

Figure 7 shows how the value of the most valuable interconnection changes with the cost of storage. The value of each interconnection changes linearly with the storage cost, and there was no change in the most profitable interconnections. It can be seen that as battery prices become extremely low (less than $1.2 per kWh) there are no interconnections that are profitable. However, for all costs above this there is at least one interconnection that adds value.

5.2. Generation costs

Given that the chosen interconnections may depend on the chosen renewables, this section explores how the results change with different generation cost parameters.

5.2.1. Cheaper solar power

Here we re-ran the analysis with all parameters fixed except the price of solar power assumed in equation (3). Instead we use a 50% reduction in the 2030 price, of $0.385m per MW. The system sizing optimization was re-run and the changes to system composition are visualized in Figure 8. It can be seen that in some regions the re-

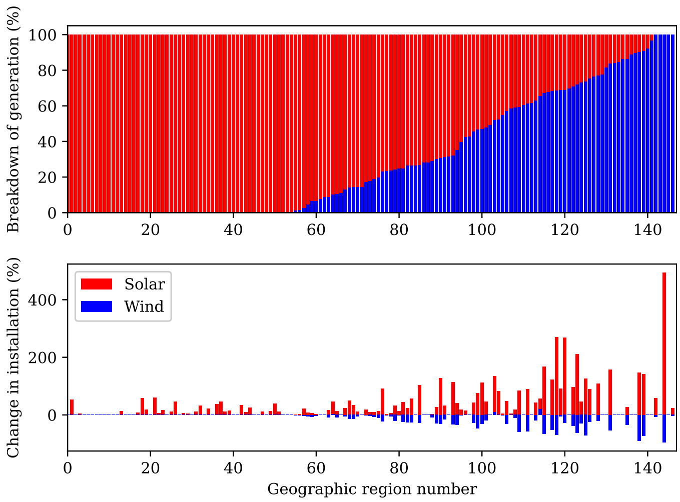


Figure 8: The top plot shows each region's original break down of solar and wind generation, and the bottom plot shows the change in solar and wind generation if solar power is 50% cheaper. Regions are ordered by their percentage of installed solar power.

duction in solar price leads to a replacement of some wind capacity with solar (and is some cases a significant amount). However, it is also noticeable that the optimization increases the oversupply factor of many countries. This can be seen by the increases in solar even for countries which only installed solar power. Also that the sum of the added solar is (visually) clearly larger than the removed wind capacity. This is because the solar power is also cheaper compared to the battery storage, so it becomes more cost effective to install additional generation rather than storage. It should also be noted that for a small number of regions the reduced solar price also resulted in an increase in installed wind capacity. Again, this is likely due to a reduced storage capacity.

The optimal interconnection algorithm was then re-run with these different renewable installations. Figure 9 shows how the interconnections compared to the original scenario. We can see that overall a similar number of interconnections are profitable in the cheaper solar power scenario, however the precise interconnections chosen were significantly different – with two thirds of the connections being different. On average the savings that the interconnections provide was about 20% lower (although still highly profitable). This suggests that when solar is more dominant in the electricity mix the interconnections are used less frequently.

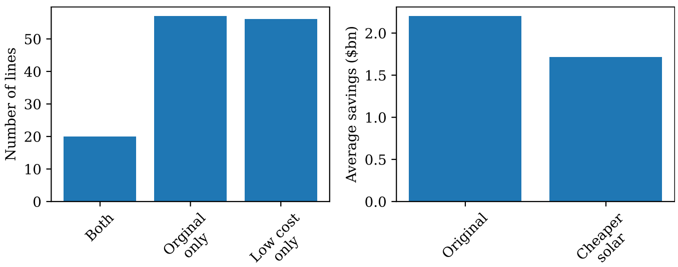


Figure 9: A comparison of the number of interconnections installed in the original vs. cheaper solar scenarios, and the average savings that they provide.

5.2.2. *Cheaper wind power*

We also considered a similar scenario for wind power: where other costs remain fixed but the 2030 wind cost falls by 50% to $0.65m per MW. Figure 10 shows the changes in optimal system composition with the reduced wind power. Compared to solar power we see a more significant shift towards wind power away from solar power – even in countries which originally had predominately solar. There is also a slight increase in oversupply, but much less significant than in the previous case. This suggests that a decreased wind price significantly increases its cost effectiveness compared to solar power, but not to battery storage.

The difference in the chosen connections is displayed in Figure 11. Similar to the cheaper solar power case study, as similar number of connections are chosen but many of them are different. Contrary to the previous case, the average savings that the interconnections provide is actually higher than in the counterfactual case, suggesting a higher utilization of the connections. This may be because wind speeds are more subject to local effects, meaning that the wind power between two areas is more likely to be complementary (even over shorter distances).

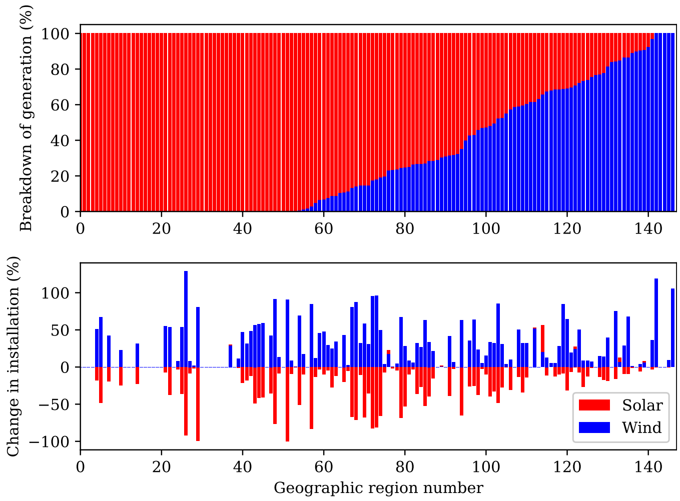


Figure 10: The top plot shows each region's original break down of solar and wind generation, and the bottom plot shows the change in solar and wind generation if wind power is 50% cheaper. Regions are ordered by their percentage of installed solar power.

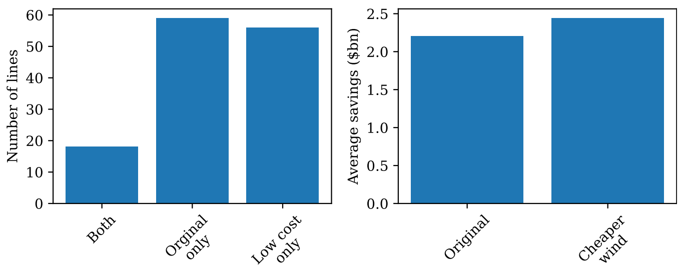


Figure 11: A comparison of the number of interconnections installed in the original vs. cheaper wind scenarios, and the average savings that they provide.

5.3. *Length of simulation period*

This section seeks to quantify the importance of the hourly demand data used on the study results. Unfortunately, it was not possible to compare 2019 with another year because: (a) previous years were not available for all sources and

(b) subsequent years were pandemic years, where electricity demand was significantly different [48]. Instead, we consider the effect of only using half of the simulation window. This will capture the significance of using a full season as well as the effect of changing input data. We therefore ran the simulations twice using the first half and then the second half of the data, thus capturing seasonal variation in both sets. The differences in the chosen connections and their values are displayed in Figure 12.

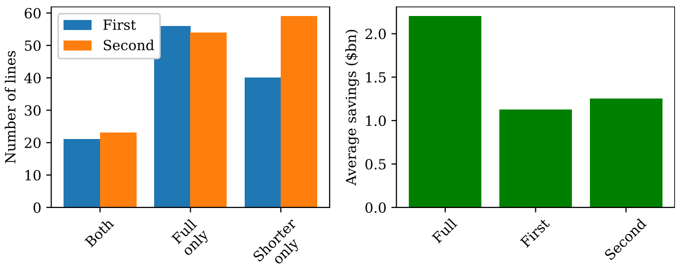


Figure 12: A comparison of the number of interconnections installed in the full length vs. half year simulations, and the average savings that they provide.

Using either the first half or the second half of the data again significantly changes the precise interconnections which are chosen; with the first year of the data selecting fewer total connections and the second half slightly more. More noticeably the value that the interconnections provide is significantly smaller when only using half the dataset (regardless of which half). From this we can conclude two things: (1) that the interconnections are not being chosen based on a single "extreme" event (e.g. a period of low wind and solar output). If this were the case we would see convergence of the full solution with one set of the data (whichever contained the extreme event). (2) Not using the full simulation period underestimates the value that the interconnection will provide. This could be because not taking into account the full season neglects the potential for inter-seasonal storage, thereby increasing the total storage requirement when we size for only six months of data.

6. Conclusion & Discussion

This analysis used hourly demand and weather data from 155 regions across the globe to assess how the introduction of renewable energy will change the value of interconnection between electrical networks.

In a high renewables scenario, a larger number of interconnections are profitable, and they provide greater savings than in a largely conventional generation scenario. Many of the interconnections profitable using dispatchable generation were not profitable with high penetrations of renewable energy. This result is especially important when considering planning for future power systems, because HVDC connections will operate for 30 years, so the shift towards renewable generation should be considered when assessing whether to commission a new interconnection.

We found that the benefit of the interconnection was often unevenly split between the two regions; on average the areas with a larger electricity market experienced more of the benefit, and in a renewables scenario the area further from the equator received a larger share. This has implications for how the funding for a HVDC project is split between the two regions, although the revenue from electricity sales may counteract these imbalances over time.

A sensitivity analysis was performed testing the resiliency of the results to different cost parameters and input data. In all cases considered, we still found a large number of interconnections profitable in the renewable generation scenario, and with savings significantly above the conventional generation case. Therefore, we feel confident concluding that additional cross-border interconnections will be cost competitive to battery energy storage in a high renewables scenario. However, we found that the specific interconnections chosen as "optimal" and the value they provided were highly sensitive to inputs – particularly to the renewables mix and demand data used. Therefore, in order to determine the "optimal" set of future interconnections more accurate modeling of future demand and renewable mix is required.

Given the benefit of cross-border interconnections in a renewable generation scenario, and the disparity between the conventional generation scenario, we would make the following recommendations to industry and policymakers. First, that cross-border interconnection may supplement energy storage in balancing renewable generation and, given the timelines of these projects, rapid action is required if these cost savings are to be realized. Second, that whether an individual connection is valuable depends on many factors including: the demand differences, the renewable mix, and the relative locations. Therefore, individual analysis is necessary to determine whether a potential interconnection is valuable – promising factors include smaller markets, countries closer to the equator, and areas with high wind power. Finally, that it is essential to consider the future renewables mix when considering a potential interconnection project, because some connections may cease to be profitable based on a changing fuel mix.

It is worth noting that flexibility or price sensitivity of demand was excluded from this analysis; only the investment trade-offs between interconnection and storage were considered. The decision to exclude it from this analysis was based on the unclear picture of the future demand profile, and the degree to which it would be flexible – and these things are likely to be different for each of the considered geographic areas. However, flexibility of demand is likely to play a role in synchronisation of demand with renewable generation, and so the value of flexibility compared to interconnection and storage needs to be studied in the future.

Appendix: Electricity Demand Data

The sources for the hourly electricity demand data are listed in Table 2. A time-synchronised, cleaned version of the 2019 data is provided alongside this paper, and can be downloaded at: `https://constancecrozier.github.io/files/demand2019.csv`

Table 2: The sources of hourly transmission level electricity demand data

Area	**Regions**	**Source**
Argentina	8	[Link]
Australia	5	[Link]
Australia (West)	1	[Link]
Brazil	4	[Link]
Canada (AB)	1	[Link]
Canada (BC)	1	[Link]
Canada (NB)	1	[Link]
Canada (N& L)	1	[Link]
Canada (Ontario)	10	[Link]
Chile	1	[Link]
China	30	[Link]
Costa Rica	1	[Link]
Europe	45	[Link]
Georgia	1	[Link]
Guatemala	1	[Link]
India	5	[Link]
Japan	1	[Link]]
Malaysia (Peninsular)	1	[Link]
Mexico	9	[Link]
New Zealand	5	[Link]
Oman	1	[Link]
Russia	7	[Link]
Singapore	1	[Link]
Turkey	1	[Link]
United States	13	[Link]

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