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Exploring sustainable electricity system development pathways in South America's MERCOSUR sub-region

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ABSTRACT

We explore sustainable electricity system development pathways in South America's MERCOSUR sub-region under a range of techno-economic, infrastructural, and policy forces. The MERCOSUR sub-region includes Argentina, Brazil, Chile, Uruguay, and Paraguay, which represent key electricity generation, consumption, and trade dynamics on the continent. We use a power system planning model to co-optimize investment and operations of generation, storage, and transmission facilities out to 2050. Our results show that, under business-as-usual conditions, wind and solar contribute more than half of new generation capacity by 2050, though this requires substantial expansion of natural gas-based capacity. While new hydropower appears to be less cost-competitive, the existing high capacity of hydropower provides critically important flexibility to integrate the wind and solar and to avoid further reliance on more expensive or polluting resources (e.g., natural gas). Over 90% emission cut by 2050 could be facilitated mostly by enhanced integration (predominantly after 2040) of wind, solar, and battery storage with 11%–28% additional cost, whereas enhanced expansion of hydropower reduces the cost of low-carbon transition, suggesting trade-off opportunities between saving costs and environment in selecting the clean energy resources. Achieving high emission reduction goals will also require enhanced sub-regional electricity trade, which could be mostly facilitated by existing interconnection capacities.

1. Introduction

1.1. The importance of identifying pathways to clean electricity systems in south america

South America's twelve nations are diverse in numerous respects, but their social and economic development objectives share several common themes. In particular, the region has ambitious plans to achieve the sustainable development goals (SDGs), increase agro-economic productivity, mitigate climate change, and achieve water and energy security [1]. The continent also has abundant natural resources (e.g., energy, water, and land) that could be exploited to achieve these objectives. Transitioning to a clean energy future could promote multiple such societal objectives. For example, increasing the deployment of renewable energy (e.g., hydro, wind, and solar power) has the potential to improve energy and water security; promote achievement of numerous SDGs, including human health and well-being; and mitigate climate change [2,3]. However, the technical pathways to clean energy expansion on the continent have remained largely unexplored in the literature, as have the techno-economic, infrastructural, and policy forces that could shape future power sector pathways.

South America would seem to be well-positioned to limit its power sector emissions, given more than half of the region's electricity generation mix has historically come from hydropower, with around 25% coming from natural gas [4]. Yet, to meet the IPCC's average carbon budget for 1.5 °C or well-below 2.0 °C warming limits, the region might need to not only limit fossil-based electricity capacity expansion, but also to retire 10%–16% of existing fossil-based capacity before it reaches the end of its technical lifespan [5]. Despite national-level targets and commitments to limit GHG emissions, the electricity demand growth in the region has outstripped the growth of low-emissions supply over the last few decades, resulting in a rise in natural gas-based thermal generation. For example, the share of hydropower in Brazil's total installed capacity declined by 13 percentage points over

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2007–2017, made up for in part by a 7 percentage points increase in thermal capacity share [6]. The recent slow growth of hydropower in South America has been influenced by drought-induced decline in hydropower generation and concerns over the socio-environmental impacts of several large hydropower projects, while gas-based generation was preferred over solar and wind for grid reliability and cost-competitiveness [4,6]. Consequently, the contribution of the power sector in total energy-related emissions in South America increased from less than 15% in 2005 to 29% in 2015, although this contribution is less than the global average of 44% [4]. Given this recent growth in emissions share, limiting GHG emissions in future capacity expansion in South American electricity systems requires careful consideration of the economic, infrastructural, socio-environmental, hydroclimatic, and policy implications of possible development pathways.

1.2. Study area and its natural resources

Here, we focus on the power system development of five countries – Argentina, Brazil, Paraguay, Uruguay, and Chile (collectively referred to as a 'sub-region' in this paper) – which represent major electricity generation, consumption, and trade dynamics in the South America region. Brazil is South America's largest economy and electricity consumer. Argentina, Chile, and Uruguay are also among South America's largest per capita electricity consuming nations [6], whereas Paraguay is the largest exporter on the continent, supplying at least one-fifth of Brazil's electricity consumption [7]. Aside from Chile, these countries are founding members of the Southern Common Market (MERCOSUR, for its Spanish initials), an economic trade bloc for regional integration, whereas Chile is an associate member [8]. All five countries are already interconnected through high-voltage transmission lines (Table S1). Our study captures the majority of power exports that currently take place on the continent, as 90% of current exports are from Paraguay to Brazil [9]. However, the interconnection facilities are relatively underutilized so far — which indicates that lucrative opportunities exist for the sub-region to expand electricity trade using the existing capacity of interconnection lines. Timilsina et al. (2020) [9] estimated that the existing interconnection lines across South America could facilitate 3-7 times higher cross-border trade compared to current levels, which could reduce the overall cost of electricity supply by more than 1.5 billion USD per year in the region, as certain countries can import cheap electricity and reduce reserve capacity. Such cost savings could substantially improve socio-economic conditions in the region. The cross-border trade may also enable the sharing of clean energy resources for a sustainable low-carbon transition.

Although the growth rate of solar and wind in South America is substantially higher than the global average [10], the national capacity shares of variable renewable energy (VRE) resources are still mostly below 10%, except for Uruguay, which has a diversified clean capacity portfolio comprised of 31% wind and an equal share of hydro, as of 2020 [9]. For future expansion, Brazil, Argentina, and Chile have substantial unexploited hydro potentials (Paraguay and Uruguay have already exploited the majority of their hydro potentials) and reserves of natural gas and coal, while each of the five countries has vast potentials for solar and/or wind power (Table S2). Other potential resources include biomass, nuclear, oil, diesel, and geothermal. Argentina, Brazil, and Chile are also well-equipped with interconnected pipelines and Liquefied Natural Gas (LNG) terminals to export and import natural gas [11].

1.3. Gaps in the current literature

Previous studies mostly projected hydropower- and fossil-based expansion pathways for South American power systems, without uncovering the possibility of more sustainable and diversified clean energy pathways, as have been identified for other regions such as the U.S. [12, 13], Europe [14,15], Southeast Asia [16], and Southern Africa [17]. Extensive hydro-dependence may increase the vulnerability of power systems to the impacts of droughts [18,19], while high fossil-based expansion can undermine regional and global climate mitigation objectives. We argue that previous South America-focused studies have generally not projected more substantial deployments of renewable and storage technologies because they have one or more of the following characteristics: (1) projections of future cost and performance of renewable and storage technologies are relatively pessimistic, (2) capacity expansion is modeled at a relatively coarse spatiotemporal resolution, which may prevent economically feasible VRE resources from being selected, (3) are not focused on power sector decarbonization as a major driver of future change, or (4) do not consider cross-border trade potentials.

For example, de Moura et al. (2018) [11] used an energy planning model, OSeMOSYS [20], to project that about 75% of new capacity in Brazil would emerge from hydro and coal expansion through shortly after mid-century. Several studies [21–23] also project heavy reliance on hydro and fossil (with carbon capture and storage (CCS) when considering future decarbonization) resources in South America using integrated assessment models with pessimistic cost-projection and/or coarse spatiotemporal representations of VRE resources. For six countries including the MERCOSUR sub-region, Santos (2021) [24] projected 22%–25% capacity share of on-shore wind by 2050 but with less than 1% solar and 36%–43% of hydropower capacity. Some studies have projected increased VRE penetration in South America, but either for a single country (e.g., [25]) or as part of global studies without regional details (e.g., [26]). Although Barbosa et al. (2017) [27] showed that South and Central America's regional power system could fully rely on renewables by 2030, such a transition may not be practically feasible given most of the countries in the region target to reach net-zero emissions in around 2050 [28,29]. Other studies [30,31] proposed net-zero deep decarbonization pathways by 2050 for certain countries in the region based on around 50% electricity generation from hydropower, wind, and solar with the rest from CCS-based fossil fuels and/or nuclear, but they did not consider potential for regional power trade. Similarly, Moksnes et al. (2019) [32] explored South America's future electricity infrastructure under varying demand, cost, and emission projections, but without considering potential expansion of electricity trade.

1.4. Research goal: exploring clean electricity system development pathways

To address these gaps, we explore mid-century development pathways of the electricity systems in MERCOSUR sub-region under a wide range of economic, infrastructural, and policy assumptions that can influence their sustainable development. First, we examined how future costs of renewable technologies and natural gas prices can influence the investment and operations of generation, storage, and interconnection facilities. Second, given its high existing capacity share, we investigated the potential effects of retiring installed hydropower earlier than anticipated. Third, we examined how the power system may evolve and operate (e.g., hourly dispatch) under different policy interventions, such as setting decarbonization or VRE generation goals. Fourth, we explored the evolution of sub-regional electricity trade, its role in low-carbon transitions, and investment requirements for new interconnection lines. Finally, we explored the spatial distribution of the economically feasible hydro, wind, and solar projects under different scenarios, and investigated factors that could potentially influence their economic feasibility. These investigations allowed us to uncover unique insights into possible sustainable energy development pathways for the sub-region, which are particularly useful for national-to-regional level policies to identify the plausible range of extent and timing of required investments in different clean energy resources for a low-carbon electricity system. This in turn could help the governments to set more efficient and sustainable incentives and market rules to promote relevant investments.

Table 1
Eight scenarios with varying techno-economic, infrastructural, and policy assumptions. For each alternative scenario, only changes to reference scenario assumptions are specified.

		Scenario dimensions				
		Costs of solar, wind, and battery	Natural gas (NG) price	Transmission (Tx) inter-connections	Retirement of installed hydropower	Climate mitigation target
Scenario names	*Reference*	Mid	Static	Optimized	100 years	None
	Static RE cost	Static				
	Low RE cost	Low				
	High NG price		High			
	Existing Tx			Existing		
	Hydro ret. 60y				60 years	
	Emission cut 90%					90% emission cut
	VRE gen. 80%					80% VRE share

2. Scenarios

2.1. Overview

For the aforementioned investigations, we design eight scenarios (Table 1) which vary across techno-economic, infrastructural, and policy assumptions. Each scenario (i.e., each row of Table 1) consists of a unique combination of uncertain factor levels in the following five categories (i.e., columns of Table 1): costs of solar, wind, and battery technology; natural gas price; transmission interconnections; retirement of installed hydropower capacity; and climate mitigation target. Below we provide details about uncertain factor levels, and the scenarios that sample these levels to produce unique narratives.

2.2. Scenario dimensions

Costs of solar, wind, and battery technology. The cost of renewable power generation is declining [33,34], though uncertainty surrounding future costs is still substantial [35,36]. Here we capture uncertainty in the future capital costs of building wind and solar power generation facilities. We use three different levels of cost assumptions across our scenarios, which are based on NREL Advanced Technology Baseline (ATB) projections for 2019 [37].

The ATB-2019 *Mid* case is used in our *Reference* scenario, and is characterized by reductions in the capital costs of wind, solar, and battery storage by 36%–53% over 2020–2050 [37]. In the *Static RE cost* and *Low RE cost* scenarios, we assessed the effects of relatively slow (no change in costs) and fast (steeper cost declines) advancements in solar, wind, and battery technologies, respectively. In our *Static RE Cost* scenario, we assume capital costs remain the same as those of 2020. Finally, in the *Low RE Cost* scenario, we use the ATB-2019 *Low* or advanced technology improvement case, which projects reductions in the capital costs of the VRE technologies by 46%–75% over 2020–2050 [37].

Natural gas prices. Natural gas has played an important historical role in the sub-region's power generation mix, and several studies have projected this role to remain strong [24,31]. Increasing natural gas prices can encourage fuel switching, either to more carbon-intensive and polluting fuel sources (e.g., gas-to-coal switch, as observed in 2021 globally [38]), or to cleaner sources of generation, and thus can have substantial impacts on costs and emissions.

In our *High NG Price* scenario, natural gas price increases following the *High* projection of ATB-2019, increasing annually by 0.15 USD/MMBtu. In all other scenarios (including the *Reference*), natural gas prices remain the same as average 2020 prices (i.e., *Static*).

Transmission interconnections. Electricity trade via interconnections represents an opportunity to efficiently and cost-effectively meet clean energy demands across the sub-region by pooling high-quality resources. While [9] showed the possibility of substantial short-run benefits from enhanced cross-border electricity trade in South America, regional coordination has been seen as a key driver of the low-carbon transitions in many other parts of the world [39].

Most scenarios, including the *Reference*, assume cost-optimal capacity expansion of the interconnection lines (i.e., *Optimized*), in which investments on interconnection lines are co-optimized with generation and storage. However, we also explore an *Existing Tx* scenario, in which interconnection lines remain at 2020 levels into the future (i.e., *Static*), reflecting a lack of investment in future transmission capacity. In all scenarios, we assumed full coordination among the five countries, given they are already interconnected, have cross-border electricity trades, and are part of a common economic bloc (MERCOSUR).

Retirement of installed hydropower capacity. While the average economic lifespan of a hydropower dam is often assumed to be 100 years [40] for planning purposes, dam lifetime can be substantially less, due to aging, sedimentation, worsening extreme events (e.g., floods), and socio-environmental concerns [41]. Particularly, the aging of existing dams in Brazil with a median age over 50 years could cause loss of productivity and substantial costs for repair and maintenance [42], while some dams in the sub-region could retire early to facilitate strategic dam planning to limit socio-environmental impacts [43]. Because hydropower can strongly influence the grid balance and can provide substantial flexibility to accommodate intermittent supply from solar and wind resources [44], it is important to understand the sensitivity of the electricity system's future evolution to the early retirement of installed dams.

The *Reference* and all other scenarios reflect the standard 100-year lifetime that is often assumed in planning studies for hydropower dams, while the *Hydro ret. 60y* scenario reflects early retirement at a 60-year lifetime.

Climate mitigation target. Climate change is central to the national objectives of all countries in the sub-region. Uruguay's target is to obtain a net-zero transition by 2030, whereas the target year is 2050 for the other four countries [28,29]. The countries also have different targets for VRE expansion in the near future for 2025 or 2030 (Table S3).

Our *Reference* scenario includes no climate mitigation or clean energy targets. To explore climate mitigation, in the *90% emissions cut* scenario, the annual GHG emissions linearly decline over 2020–2050, where the 2050 emissions reach below 10% of 2020's level. Achieving net-zero CO_2 emissions shortly after mid-century is roughly consistent with power sector objectives in other studies focused on limiting end-of-century temperature increase to well below 2 °C [45]. Alternatively, the *80% VRE share* scenario gradually increases VRE generation share to 80% by 2050, reflecting renewable portfolio standards at comparable percentages to those discussed for other regions [17,46].

Reference. This scenario serves as a baseline against which the seven other scenarios above will be compared. The *Reference* assumes a medium (i.e., *Mid*) rate of advancement in solar, wind, and battery technologies; static natural gas price; cost-optimal expansion of interconnection lines; a standard hydropower dam lifetime of 100 years; and no climate mitigation policy.

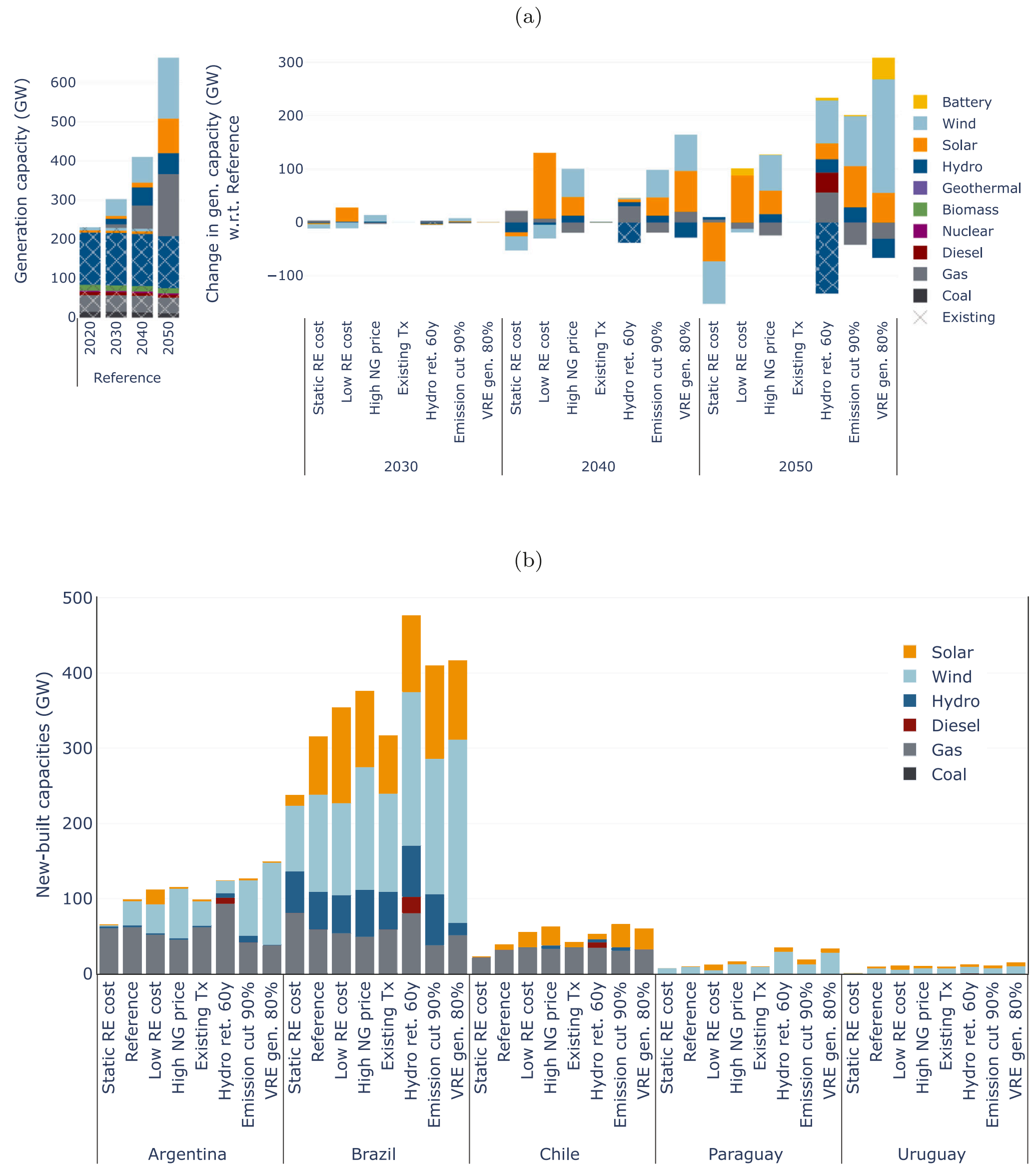

Fig. 1. (a) Evolution of sub-regional installed and new (hatched and solid bars, respectively) generation capacities across 2020–2050 for the Reference and respective changes in the alternative scenarios. No new capacity is built in 2020 across all scenarios, and hence, is shown only for the Reference. (b) Country-wise new generation capacities over 2020–2050.

3. Data and methods

To explore sustainable electricity system development pathways for the MERCOSUR sub-region, we developed a modeling framework, fully based on open-source data and models including an electricity system model and a hydrologic model. We uniquely harmonized the spatiotemporal details of the demand and supply sides to represent key system dynamics while maintaining computational tractability. In particular, we used project-level potentials and time-varying energy budgets of hydro, solar, and wind power to capture their spatiotemporal variability.

3.1. Electricity system model

We use GridPath to simulate the cost-optimal investment and operating conditions of the five-country electricity system for seven time periods from 2020 to 2050 using a five-year time step. GridPath is an open-source power system modeling platform [47] – written in the Python-based Pyomo optimization framework [48] – which can simulate both production-cost and capacity expansion with performance comparable to PLEXOS (a widely-used commercial energy system simulation software) [49]. Our model includes five demand zones, each representing a country, which are connected by cross-border transmission lines for regional electricity trade. Using 2020's demand, supply, and interconnection facilities as a baseline, GridPath co-optimizes operation, decommissioning, and deployment of conventional and renewable generators, storage, and cross-border transmission lines in each time period. While the cost-optimization-based model allows us to reveal cost-effective and sustainable development pathways for the electricity systems, it does not explicitly consider some other market-level investment and operating strategies (e.g., profit-maximization of individual firms).

3.1.1. Grid operations

Within each time period, generators and storage are dispatched to cost-optimally meet country-wise demand over 24 h for 12 representative days of the year. Each day is made up of the average hourly demand of each month weighted by total days of the month (e.g., 31 for January), and hence, a full year is represented by 288 (24 × 12) time-points. The hourly dispatch of conventional generators (e.g., coal, gas, oil, nuclear, biomass) is constrained by techno-economic characteristics, including ramping limits, heat rates, fuel costs, fixed and variable operating and maintenance (O&M) costs, etc. The hourly dispatch of hydropower and battery storage is constrained by daily energy availability, as they can store electricity to dispatch at a suitable time in a day. The hydropower availability also varies monthly according to seasonal hydroclimatic variability. The supply from solar and wind is based on the monthly average of 24-hourly energy availability (similar to demand). While our hourly demand represents monthly-average conditions, to account for the annual peak demand, we impose a planning reserve margin (PRM) of 15% of the peak demands in our monthly-averaged data. The 15% PRM requirement for 2020 provides a 9% buffer over the system-wide annual peak demand reported for the year in [9]. In addition, to account for the intermittency of VRE technologies, the PRM is assumed to be supplied mainly by dispatchable generators and storage with 80% effective load-carrying capacity (ELCC), but only 10% ELCC for wind and zero for solar (similar to [17]). This ensures availability of dispatchable generators and storage in case of a prolonged gap in VRE supply.

3.1.2. Capacity expansion

GridPath co-optimizes investments in new generation, storage, and cross-border transmission infrastructure for each period except 2020, which operates only on existing facilities. New capacities of conventional generators and battery storage are selected linearly from country-scale resources. The new solar and wind capacities are also selected linearly but from spatially-distributed projects of different sizes (potential capacity) and quality (energy availability) – the data of candidate projects are described in Section 3.3. The selection of new hydropower capacities is based on spatially-distributed projects of different sizes and quality, but hydropower projects are selected in binary (i.e., the project is either built or not) rather than continuous terms. All investment decisions, including linear expansion of cross-border transmission lines, depend on several other techno-economic parameters, including capital and operating costs and lifetime of the infrastructure. A discount factor of 7% – consistent with previous electricity capacity expansion studies [11,50] for the region – is used to estimate the net present value of costs incurred in each period. Overall, the model forms a mixed-integer linear programming problem, which was solved using the Gurobi solver [51].

3.1.3. Input data

For electricity demand, we first create the month-hourly data for 2020 using country-specific hourly and monthly demand profiles and annual energy demand for the year, retrieved from [9]. Then, we use annual electricity demand growth rates under historical socioeconomic growth (Table S4) to linearly extrapolate the demand time series into the future for other investment periods. Country-wise installed generation capacities of conventional technologies – mostly comprising coal, gas (CCGT and OCGT), diesel, nuclear, and biomass (Fig. 1(a)) – are adopted from [9,52]. New candidate conventional generating projects of installed technology types are considered for each country. Candidate projects for coal and gas with CCS, diesel, and battery storage are considered for all countries. For hydro, solar, and wind power, we use spatially distributed installed and candidate projects, as discussed in Sections 3.2 and 3.3.

The capital costs of most technologies are adopted from [37], except for hydropower, for which we use the regional average capital cost for South America [53]. All capital costs are assumed to remain constant across time, except for wind, solar, and battery, which use time-varying capital costs according to the 'mid' and 'low' projections (Table S7) of NREL's ATB-2019 [37] in different scenarios (see Table 1). Country-wise fuel prices (Table S5) are adopted from [9]. While all fuel prices are assumed to remain static across time, the price of natural gas is assumed to rise according to the *High* projection (Table S7) of ATB-2019 in the *High NG price* scenario. Fuel-specific emission factors – 0.106, 0.058, and 0.08 tCO_2/MMBtu for coal, gas, and diesel respectively – are adopted from the Energy Information Administration [54]. Other technical and economic parameters (Table S6) are adopted from different global sources [55–57].

The transfer capacities of the existing cross-border transmission lines (Table S1) are adopted from [9], whereas the interconnection capacities are allowed to be expanded linearly and cost-optimally from 2025 onward in all scenarios except *Existing Tx*. Lengths of the interconnection lines are estimated from the centroidal distances among the countries. A bulk transmission loss of 1% per 100 miles (as per [58]) is assumed for both existing and new-built lines. The capital costs for new transmission lines (1.74 USD/KW-km) and substations (60.3 USD/KW) – assuming 230 kV High Voltage Alternating Current (HVAC) lines are to be built – are adopted from the Western Electricity Coordinating Council [59]. Intra-country grid expansion is not considered for any new generation capacities except new solar and wind, for which we estimate the levelized cost required to install new lines from the nearest existing transmission lines to the new project sites, and add that cost to the investment cost. This cost implicitly incorporates the site feasibility of new solar and wind projects in terms of distance from the existing transmission network and associated investment requirements.

3.2. Hydropower simulation

We incorporate the spatial and seasonal variability of hydropower production in our model. The capacities of existing hydropower plants in the river basins across the sub-region – including Amazon, La Plata, Negro, and Colorado – are adopted from [52,60]. For future expansion, out of ~1,100 candidate projects reported in [61], we consider only 201 projects with more than 50 MW capacity, which covers 91% of the total 112 GW planned hydropower capacity in those five countries.

To estimate the monthly-varying hydropower availability as GridPath's input, we use Xanthos, a global hydrologic and water management model [62,63], which was previously used by several studies [64–66] for hydropower simulation in South America. Xanthos was forced with the WFDEI meteorological bias corrected reanalysis dataset [67] to simulate the monthly streamflow and hydropower production for 1970–2010 at existing hydropower plants. We use the monthly time series of historical hydropower production to estimate monthly-varying long-term average capacity factors for the existing hydropower plants. For candidate projects, hydropower production is not modeled explicitly; instead we use the average capacity factors of the nearest existing hydropower plants that fall within the same river basin. The impacts of climate change on hydropower production are also not considered, i.e., the same sets of monthly-varying capacity factors are used for each investment period.

3.3. Solar and wind data

To establish candidate wind and solar projects, we leveraged technical potential capacity data estimated at 0.5-degree resolution by [10]. We used gridded existing installed capacities at the same spatial resolution from [68]. For candidate projects, we first estimated the remaining (not yet installed) potential capacities in each grid cell by deducting the installed capacities from the potential capacity. Then, we identified 1650 solar and 978 wind project sites – with a minimum remaining potential capacity of 50 MW and 10% annual average capacity factor – to include in the GridPath simulation. These high-quality project sites comprise a total of 317 GW solar and 1,122 GW wind capacities. Country-wise total candidate project sites and potential capacity are shown in Table S8.

For each solar and wind project site, we downloaded the hourly capacity factor time series for 2020 from www.renewables.ninja [69], which were modeled using MERRA-2 (Modern-Era Retrospective analysis for Research and Applications, Version 2) climate forcings [70]. To generate the hourly capacity factor time series from www.renewables.ninja, we considered 1-axis (azimuth) technology by setting the tilt equal to latitude for solar; and Vestas V90 2 MW turbine with 100 m hub height for wind. Then, we estimated the monthly average of 24-hourly capacity factors for each solar and wind project. The month-hourly capacity factors are used in GridPath as electricity availability in the solar and wind projects across the investment periods.

3.4. Analysis

For each period, key GridPath outputs include new generation, storage, and transmission capacities, hourly dispatch, curtailment, and losses (battery charging and transmission losses) of electricity, operating and investment costs, electricity trade among the countries, and GHG emissions. We analyze these outputs across scenarios to understand the evolution of generation capacity and mix, costs and emissions, and cross-border transmission capacity and trade. In addition, we trained a random forest classification model to quantify the influence of different factors in predicting whether a given wind, solar, or hydro project would be chosen cost-optimally by GridPath in future investment periods. This allows us to test sensitivity of the investment decisions to certain predictors of the wind, solar, and hydro projects such as annual capacity factor, projected capacity, and distance of the project site from the nearest existing transmission lines. For the eight scenarios and seven investment periods, we estimate feature importance scores of the three predictors for each wind and solar project. Here, feature importance is a measure of improvement in predicting performance of the random forest classification model upon inclusion of each predictor. The first two predictors represent the project quality and size, while the third predictor represents additional investment requirements for connecting transmission lines to access electricity from the new project. However, for each hydropower project, we evaluate the feature importance of only the first two predictors.

4. Results and discussion

4.1. Techno-economic effects on the evolution of generation capacity and mix

The results from our *Reference* scenario show that with modest technological advancement, wind and solar have the potential to dominate future capacity expansion in the sub-region, but the system may still require a substantial expansion of gas capacity. If the capital costs of wind, solar, and battery technologies decline according to the ‘mid’ projection of ATB-2019, as in the *Reference* scenario, more than half (54% combined) of new generation capacity by 2050 is contributed by VREs, with 155 GW and 88 GW of new wind and solar, respectively (Fig. 1(a)). New wind capacity comes online in all countries except Chile, while solar capacity is mostly selected in Brazil and Chile (Fig. 1(b)). Achieving this extent of future expansion will require annual deployments of about 5 GW wind and 3 GW solar sub-regionally, which is likely achievable given the current impressive growth rate of VREs in those countries. For example, Brazil alone has deployed wind capacity at a rate of more than 2 GW per year between 2013 and 2017 [6]. Hydropower appears to be less cost-competitive compared to VREs — 53 GW of new hydropower (mostly in Brazil) is selected in the *Reference* scenario, which is equivalent to only about half of the total planned capacities of large hydropower projects reported in [61]. However, the system may still require a substantial (158 GW; equivalent to 35% of total new capacity) expansion of gas capacity in Argentina, Brazil, and Chile, where substantial domestic resource availability (and corresponding relatively low natural gas prices, shown in Table S5) make gas-based electricity generation cost-competitive.

The deployment of wind and solar under the *Reference* scenario increases the sub-regional generation share of wind and solar from fewer than 5% in 2020 to 28% and 9% in 2050, respectively (Fig. 2). Around 40% of 2050’s electricity supply may rely on hydropower in the *Reference* condition — mostly facilitated by the high existing capacity of hydropower. However, the generation share of hydropower shows a declining trend from its current level of more than 60%. This finding, which is consistent with the declining hydropower share found in other studies [4,6], is mainly influenced by the aforementioned slow capacity growth due to its declining cost-competitiveness compared to wind and solar technology. The gas-based generation share remains substantially high in the *Reference*, increasing from 17% to 21% over 2020–2050.

If VRE technology advances more rapidly than in the *Reference* scenario (i.e., as in the *Low RE Cost* scenario), deployment of additional solar capacity occurs relative to the *Reference* (Fig. 1(a)). In this scenario, solar is selected in favor of wind because solar costs decline at a steeper rate than wind (Table S7). This can raise the generation share of solar to 19% by 2050, 10 percentage points higher than the respective share in the *Reference*, which in turn can reduce the gas generation share to 13% by 2050 (Fig. 2). If, on the other hand, VRE technology does not advance substantially (as in the *Static RE Cost* scenario), gas capacity could further expand in place of VRE (relative to the *Reference*), raising the gas generation share to 43% by 2050. An increase in natural gas price (*High NG price* scenario) slightly deters the expansion of gas capacity compared to the *Reference*, which can be compensated for via higher integration of wind, solar, and hydro, without installing other more polluting (e.g., coal) or expensive (e.g., nuclear) resources. The gas generation share can decline to 4% by 2050 in the *High NG price* scenario, while enhanced generation of wind (40%) and solar (14%) can cost-competitively fill in most of the deficit.

4.2. Techno-economic effects on electricity system costs and emissions

The electricity system costs, comprising of operating and investment costs, do not significantly vary at the future techno-economic conditions we explored here. This implies that, with anticipated advancement of VRE technologies, clean energy pathways are possible at competitive cost. At different VRE costs and natural gas prices, fluctuations in electricity system costs in 2050 are within 10% of costs (35 USD/MWh) in the *Reference* scenario (Fig. 3). In the *Low RE cost* scenario, the investment costs for VREs are assumed to be lower than in the *Reference*, which in turn, is reflected in the slightly decreasing system cost. The slightly increasing costs in the *High NG price* scenario are driven by increased investment costs (at the same rate as the *Reference*) for new renewable capacities to reduce reliance on gas (Figure S2). The similar increasing costs in the *Static RE cost* scenario are, however, driven by higher operating costs due to increased reliance on natural gas.

Unlike electricity system costs (Fig. 3a), emissions vary substantially across scenarios (Fig. 3b). Critically, it is technically feasible, and economically competitive, to achieve futures that reliably meet demands with substantially reduced GHG emissions. Advancement of VRE technologies can help limit emissions, but reducing emissions below current levels may require policy intervention. The annual GHG emissions in 2050 are four times higher than the emissions in 2020 (100 $MtCO_2$) if the capital costs of VREs do not decline as anticipated and the system heavily relies on gas-based generation (*Static RE cost* scenario in Fig. 3). Emissions double by 2050 even if the costs of VREs decline moderately (*Reference* scenario). A steeper decline in the VRE costs, as in the *Low RE cost* scenario, can be advantageous to limit the emissions at around the current level until 2035, although, after that, the annual emissions rise to 22% higher than the current level by 2050 as the demand growth outstrips the growth of clean resources. This indicates that future VRE costs alone cannot solely enable a low-carbon future in the sub-region. Interestingly, in the *High NG price* scenario, enhanced integration of VRE and hydropower not only reduces the impacts of rising natural gas prices (with only a slight increase in the system costs), but also leads to 28% lower emissions by 2050 relative to 2020.

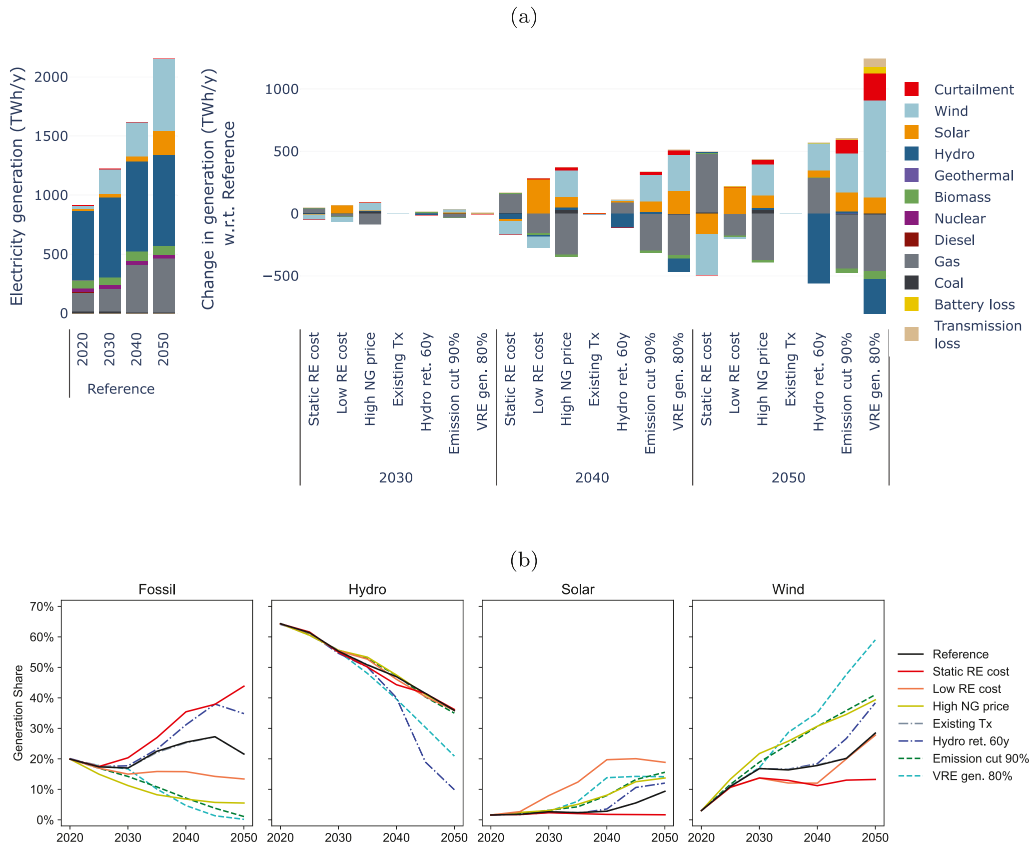

Fig. 2. (a) Sub-regional electricity generation mix in the Reference and respective changes in the alternative scenarios across 2020–2050, (b) Evolution of generation shares by fossil (aggregated shares of gas, coal, and diesel), hydropower, wind, and solar resources across 2020–2050. The generation share by each technology is shown in Figure S1.

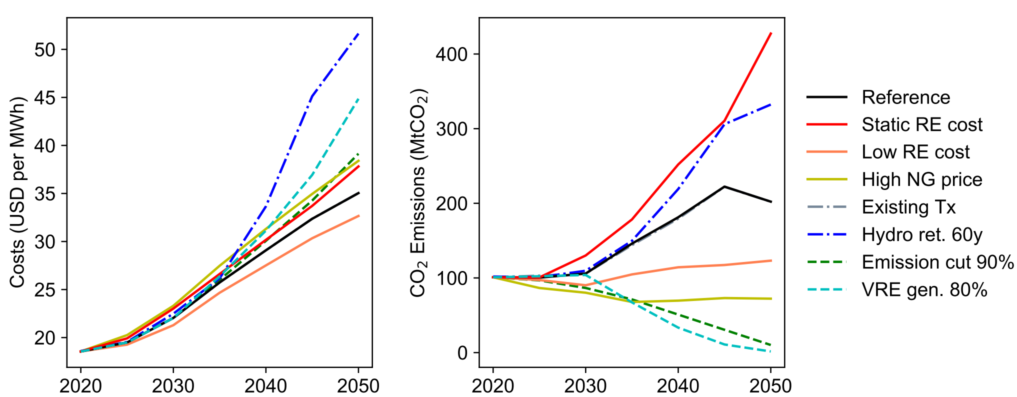

Fig. 3. Annual system costs (comprised of the operating and investment costs) and CO_2 emissions across 2020–2050. The capital costs are considered only for new generation and transmission infrastructure, but not for existing infrastructure due to limited data availability. Since the capital costs of existing infrastructure (which likely represent a large share of the costs in the earlier years of operation) are not considered, the annual costs of all scenarios show an increasing trend with the integration of new infrastructure over time. However, this does not imply that the annual costs will increase over time across scenarios.

4.3. Role of existing hydropower

Early retirement of installed hydropower can significantly affect grid operation, costs, and emissions. With a 100-year life expectancy of existing hydropower plants – as in the *Reference* – the sub-regional stock of hydropower plants existing in 2020 (133 GW) would remain unchanged by 2050. However, retiring the existing hydropower plants at 60 years (*Hydro ret. 60y* scenario) can reduce the installed hydro capacity by 29%, 77%, and 100% in 2040, 2045, and 2050 respectively. This capacity deficit is only partially offset by an additional (compared to the *Reference*) 25 GW, 29 GW, and 80 GW of new hydro, solar, and wind capacities over the planning periods, while 56 GW and 37 GW of new gas and diesel capacities are also selected (Fig. 1(a)).

Diesel capacities are selected only in 2050 when almost all installed hydro capacities get retired, yet this selection of a relatively expensive resource indicates that a plummeting supply from the existing hydropower dams can significantly affect the grid's operation. Moreover, the increased investment for the additional new capacities and higher reliance on gas result in higher costs and emissions, making the *Hydro ret. 60y* scenario the most expensive and second-highest emitting scenario (Fig. 3). This result indicates that the sub-regional power system can benefit from consistent investment to sustain hydro generation

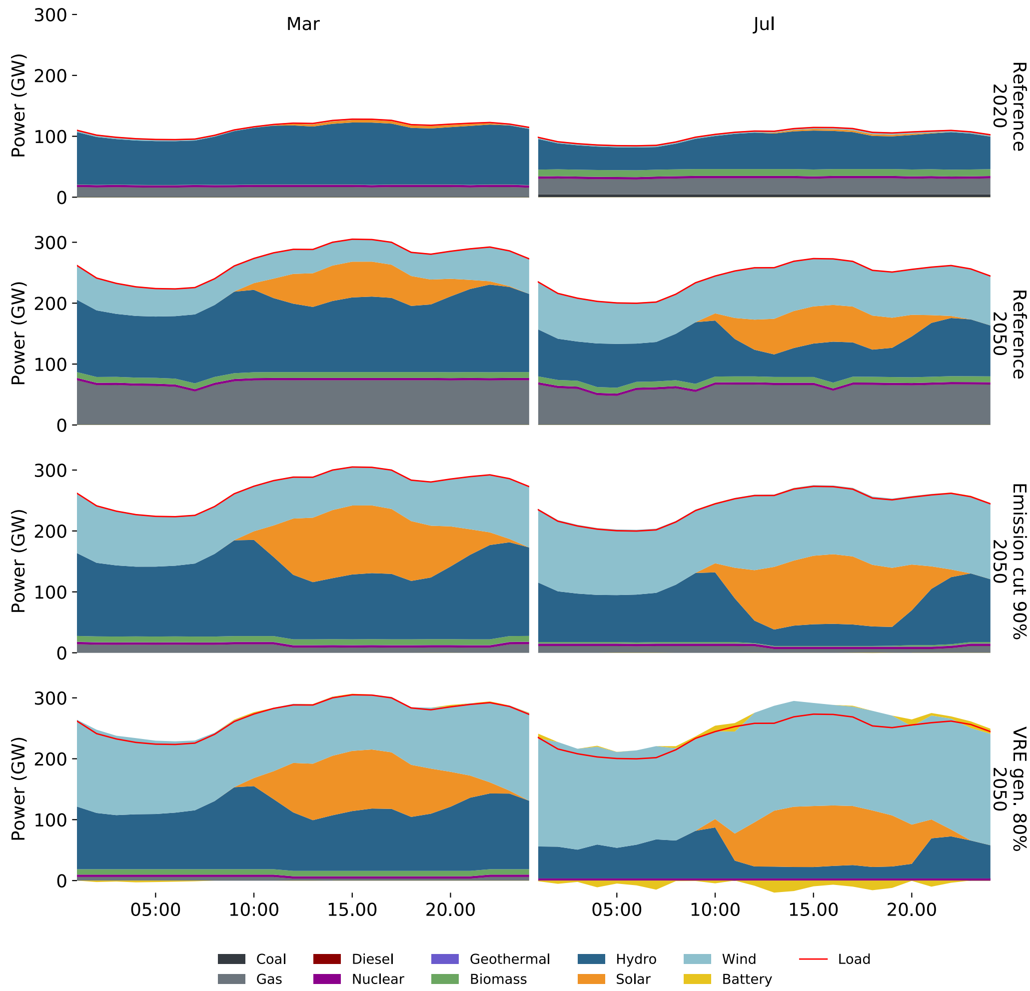

Fig. 4. Hourly electricity dispatch in representative days of March and July, two relatively wet and dry months, respectively. The dispatch in 2020 is shown only for the Reference, as it is the same across all scenarios. The dispatch in 2050 is shown for the Reference and two scenarios with climate mitigation targets. Typical examples of national-level hourly dispatch for Argentina and Brazil are shown in Figures S3 and S4.

at around the current level even though the expansion of new hydro capacities may be less than that of VREs. Sustaining hydro generation may require a wide range of efforts including paying close attention to sediment management, monitoring how climate change is altering reservoir inflows, and developing adaptive operating policies [71,72].

4.4. Low-carbon transition pathways

Diversifying investments in hydropower, wind, solar, and battery storage can lead to a sustainable transition to a low-carbon power sector. The sub-region has unique opportunities to substantially reduce the electricity sector's GHG emissions while supplying growing demands. In the *VRE generation 80%* and *Emission cut 90%* scenarios, the annual emissions decline to 1% and 10% of 2020's level by 2050 (Fig. 3), respectively. However, the *VRE generation 80%* causes 28% higher cost than the *Reference* in 2050, while the respective cost increment is 11% for the *Emission cut 90%* scenario. The higher additional cost in the *VRE generation 80%* scenario is driven by the requirement to pursue particular level of VRE generation by 2050, which in turn increases deployment of new VRE capacities (Fig. 1) and curtailment and transmission losses (Fig. 2(a)) compared to the *Emission cut 90%*. Raising VRE generation share to 80% by 2050 will require installation of 368 GW and 143 GW of new wind and solar capacities at a rate of 12 GW and 5 GW per year (Fig. 1), which are about two times higher than the respective rates in the *Reference*. On the other hand, the emission reduction target in *Emission cut 90%* will require the deployment of 248 GW and 165 GW of new wind and solar at an annual rate of 8 GW and 5.5 GW, respectively. However, more than half of the new VRE capacities in both scenarios are cost-optimally selected after 2040, which may allow sufficient lead time for structural and non-structural preparation to accelerate their integration.

The *VRE generation 80%* scenario will require 40 GW of 4–6 h battery storage during 2045–2050, as opposed to less than 2 GW battery requirement for *Emission cut 90%* (no battery is selected in other scenarios, see Fig. 1). The lower battery requirement in *Emission cut 90%* is driven by a selection of 82 GW of new hydropower (in addition to the 133 GW installed hydropower), which is 55% higher than the *Reference* and equivalent to 80% of the planned large hydropower capacity in the sub-region. The selected new hydropower capacity in the *VRE generation 80%* is only 17 GW. While the deployment of higher hydropower capacity can be advantageous for grid operation, it may cause environmental impacts [73] and expose the grid to higher risks of climatic impacts [74,75]. Nevertheless, these results indicate that diversifying the investment in hydropower, wind, solar, and battery storage can not only lead to a significant emissions reduction, but may also help to cost-effectively limit environmental externalities.

How would the power system operate with different levels of integration of hydro, wind, and solar power? In our two climate mitigation scenarios, the daytime supply of solar power can be complemented by the supply of hydro and wind power to reduce reliance on gas compared to the *Reference* (Fig. 4). In the *Emission cut 90%* scenario, the hydropower supply can facilitate the integration of wind and solar

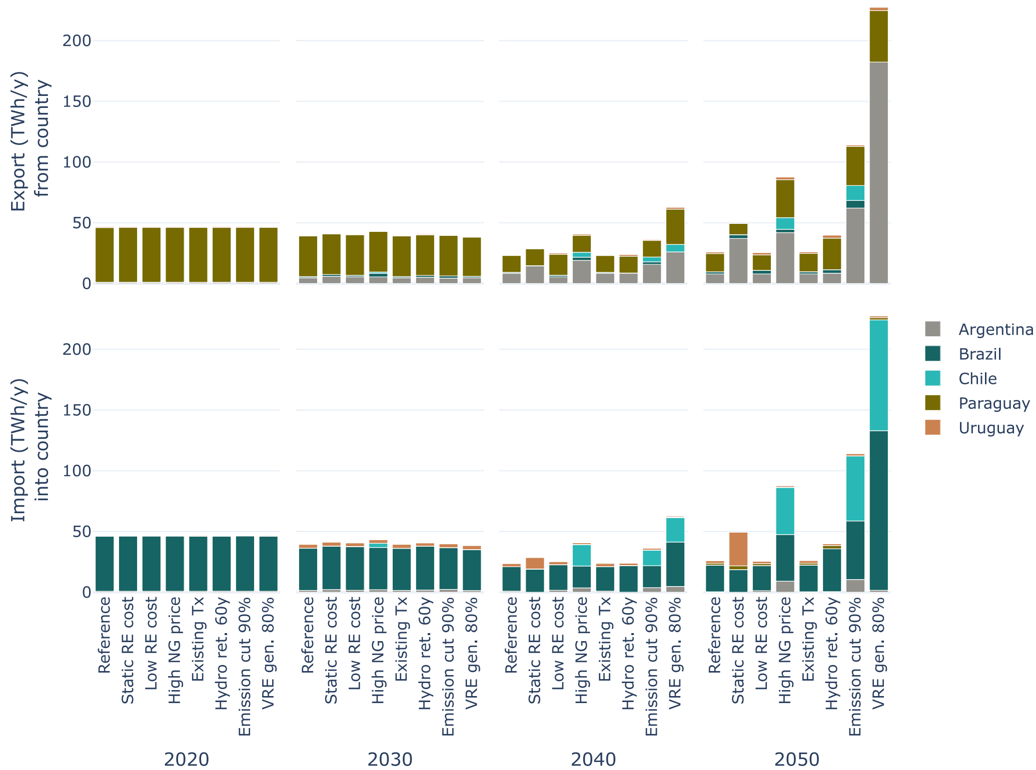

Fig. 5. Evolution of electricity export and import among the five countries across 2020–2050.

without battery storage in both wet and dry seasons. However, higher integration of wind and solar, as in the *VRE generation 80%* scenario, may require utility-scale battery storage, especially in the dry season. With higher VRE integration, supplying both peak and off-peak loads in the sub-region may require enhanced electricity trade, as shown in Figures S3 and S4, and further discussed in the next section.

4.5. Role of sub-regional electricity trade and investment in interconnection lines

Low-carbon transition with higher integration of wind and solar resources can substantially benefit from enhanced sub-regional trade. In particular, in scenarios with enhanced integration of wind, such as the *High NG price*, *VRE generation 80%*, and *Emission cut 90%* scenarios, the sub-regional electricity trade may decline until 2040 but rebound to 2-5 times higher than 2020's level by 2050 (Fig. 5). This is likely because there is enough economically feasible projected generation capacity available in each country to depend mostly on domestic generation until 2040. The increased trade after 2040 would be mostly comprised of export from Argentina to Brazil and Chile, as certain wind projects in Argentina could be more cost-competitive to expand than some VRE projects in Brazil and Chile. The cost-competitiveness of one project over another may depend on several factors including production ability, project size, and distance from existing transmission facilities – which we further discuss in Section 4.7. On the other hand, the electricity trade may slightly decrease across the entire planning period in the *Reference* and other scenarios with relatively low integration of wind, where the cost-optimal expansions of domestic capacity could supply a majority of the national-level demands. The sub-regional trade may also remain at around the current level in scenarios with substantial gas-based capacity expansion – as in the *Static RE cost* scenario – when only Uruguay would need to increase imports from Argentina.

Achieving high emission reduction goals will require enhanced sub-regional trade for better utilization of renewable resources, and this enhanced trade may require only nominal investment in interconnection lines. To facilitate such trade, up to 13 GW and 17 GW of new transmission capacity could be needed in cross-border lines from Argentina to Brazil and Chile, respectively (Table 2), which are 12 and 34 times higher than their existing transfer limits. However, the majority of the new transmission capacities are selected after 2040, allowing sufficient lead time. Moreover, diversification of the generation investment is likely to lessen cross-border transmission requirements as indicated by a relatively low new transmission capacity in *Emission cut 90%* compared to *VRE generation 80%*. Nevertheless, the investment costs for new interconnection lines are not more than 3% of the total investment and operating costs across scenarios (Figure S2). On the other hand, the *Reference*, without building any new interconnection capacity (Table 2), shows similar levels of electricity trade to the *Existing Tx* scenario, which indicates that the sub-regional trade under *Reference* conditions can completely be facilitated by the existing interconnection lines.

4.6. Spatial distribution of renewable resources

To identify a sustainable combination of hydro, wind, and solar projects, sub-regional planners should consider avoiding projects with substantial socio-environmental impacts. All forms of clean energy can have such impacts, but hydropower in particular poses concerns for South America's productive and biodiverse freshwater ecosystems (e.g., the Amazon basin), and the people who depend upon them for food, income security, and cultural value. More than 90% of the new hydropower capacity selected in the *Reference* scenario is located in Brazil, with about 70% in the Amazon River basin alone. The selected hydro capacities in the Amazon are equivalent to 69% of the basin's planned capacity, while other basins in Brazil (e.g., Tocantins, La Plata, Sao Francisco, and Parnaiba) may also experience high exploitation under *Reference* conditions (Fig. 7).

Policies focused on emissions reduction (i.e., our *Emission cut 90%* scenario) tend to promote hydropower expansion (especially in the

Table 2
New capacities (GW) added to the interconnection lines in all scenarios except *Existing Tx*, which was constrained to operate with existing transmission capacities.

Interconnection lines	Reference	Static RE cost	Low RE cost	High NG price	Hydro ret. 60y	Emission cut 90%	VRE gen. 80%
Argentina - Brazil	0	0	0	0	0	3.2	13
Argentina - Chile	0	0	0	10.8	0	15.3	17.5
Argentina - Paraguay	0	0	0	0	0	0	0
Argentina - Uruguay	0	3.4	0	0	0	0	0.2
Brazil - Paraguay	0	0	0	0	0	0	0
Brazil - Uruguay	0	0	0	0	0	0	0

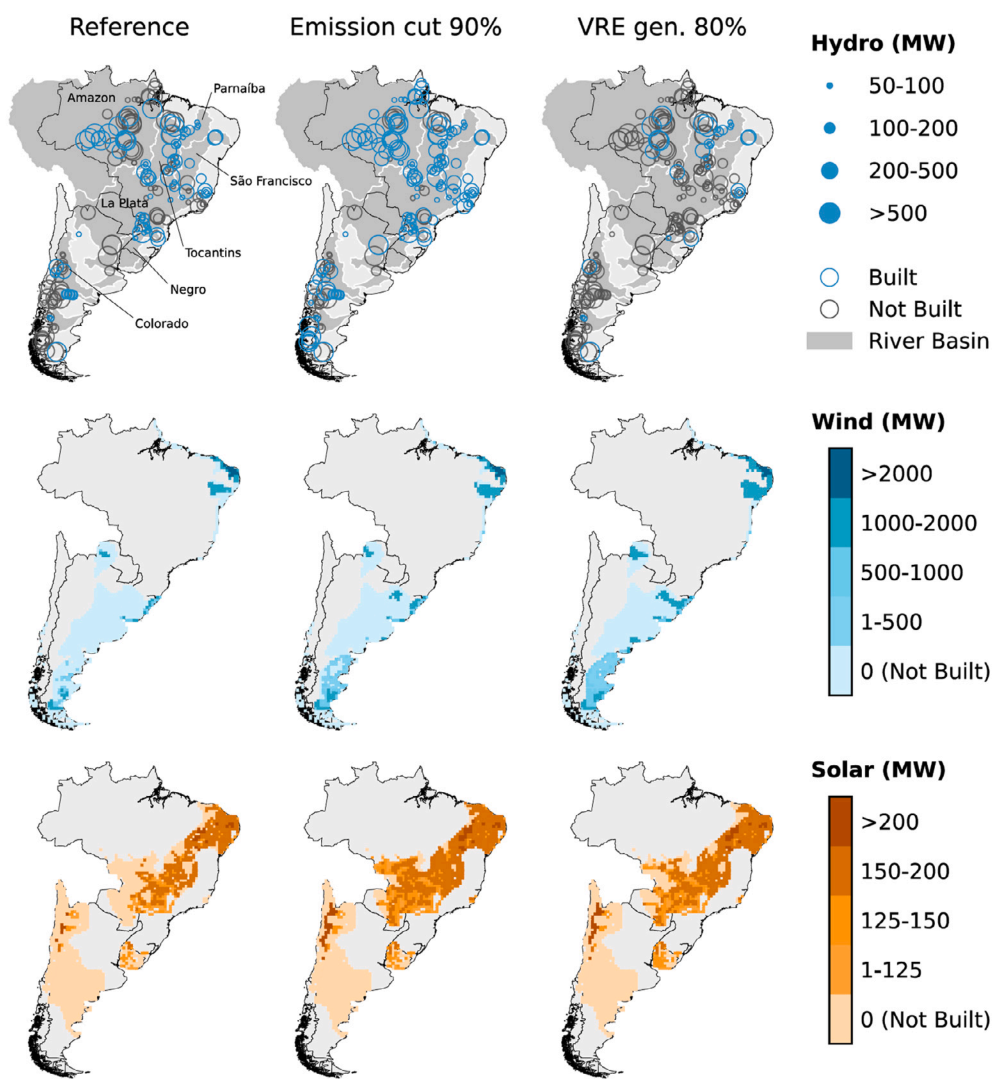

Fig. 6. Spatial distribution of new-built hydropower, solar, and wind capacities (cumulative over 2020–2050) in three selected scenarios. The wind and solar sites under the gray areas of the maps in the middle and bottom panels were screened out (were not used in the GridPath simulation) based on a threshold of minimum remaining potential capacity of 50 MW and a minimum capacity factor of 10%.

vulnerable Amazon basin), thus creating a direct tradeoff with socio-environmental impacts. The level of exploitation can rise to over 50% in almost all basins across the sub-region (with Amazon's exploitation being 94%) in the *Emission cut 90%* scenario. However, policies that promote integration of wind and solar can ease pressure on hydropower expansion. For example, in the *VRE generation 80%* scenario, the exploitation of hydropower capacity drops significantly across the sub-region, with less than 20% exploitation in the Amazon. However, as discussed earlier, hydropower offers benefits, such as improved grid operation. Its storage complements the variability of wind and solar and eases the need for costly battery storage in a VRE-dominated system, thus dampening overall system costs.

The locations of selected wind and solar projects tend to be in completely different areas of the sub-region than hydropower. This complementarity offers a distinct benefit in a low-carbon future, because a hydropower project with potential externalities (e.g., socio-environmental and biodiversity impacts [76]) can be replaced by a more sustainable VRE project, and vice versa. This also suggests that the sub-region has opportunity to pursue other development strategies – such as strategic dam planning [77], installing in-stream turbines [78], etc. – to limit the socio-environmental impacts. Spatially, wind projects are mostly selected from the northeast of Brazil, the east coasts of Argentina and Uruguay, and the west of Paraguay. Meanwhile, solar projects are selected from a wide region across the southeast of

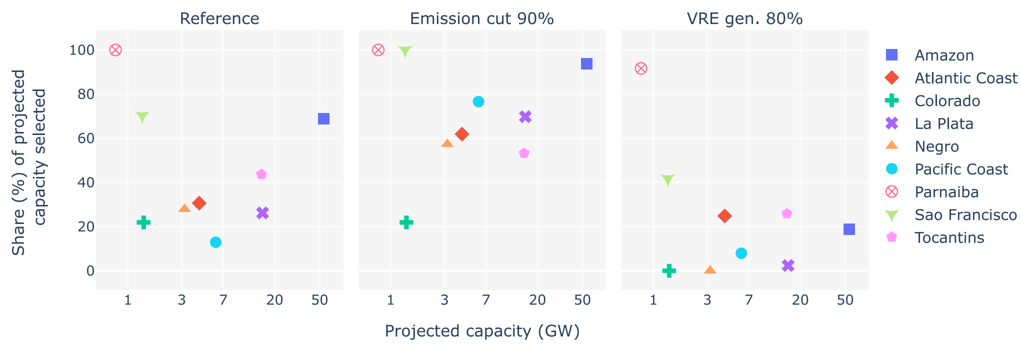

Fig. 7. Share of planned hydropower capacities (by basins) selected in three scenarios. The x-axes are in logarithmic scale.

Paraguay to the northeast of Brazil, southwest of Uruguay, and the north of Chile around the Atacama desert (Fig. 6).

4.7. *What might influence the economic feasibility of renewable projects?*

Renewable projects with higher annual capacity factor are likely to be more economically feasible, irrespective of their size and additional investment requirements for connecting to transmission lines. The feature importance scores of the random forest analysis (Fig. 8) – used to identify the effects of certain factors on the selection of a wind, solar, or hydro project across the scenarios (the higher the feature importance score, the stronger the influence of a factor on project selection) – indicates that the annual capacity factors of the wind and solar projects are likely to have a greater influence on their economic viability compared to the project sizes and additional investment requirements for connecting lines (represented by the distance of the project sites from the nearest existing transmission lines). In other words, investments in wind and solar projects with high production potential, but that are located at a greater distance from existing transmission networks, can still be beneficial. Note that this finding is based on the 978 wind and 1,650 solar sites across MERCOSUR with average capacity factors of 42.2% and 26.3% and average transmission distances of 88 km and 38 km, respectively. While investment requirements for transmission for hydropower projects are not considered, the investment decisions on hydropower projects are also dominated by their annual production potential rather than size.

5. Conclusions

5.1. *We have identified low-carbon development pathways for the sub-regional electricity system subject to the economic and operational feasibility of the grid infrastructure*

South America has abundant fossil and clean energy resources that can be used to expand regional power systems to meet growing demand. Previous studies [11,21] mostly projected hydropower- and fossil-dominated generation capacity expansion in the region, without fully considering potential future cost and performance advances in wind, solar, and battery technologies. Other studies [26,44] analytically identified the potential high integration of the VRE resources in the region, without fully evaluating their economic and operational feasibility. Here, we fill this gap, by identifying low-carbon development pathways for an interconnected electricity system in the region by evaluating the economic and operational feasibility of the generation, storage, and interconnection facilities with high spatial and temporal resolutions. For the sub-regional electricity system of Argentina, Brazil, Chile, Paraguay, and Uruguay, our results indicate that wind and solar can dominate the expansion of new generation capacities under a wide range of techno-economic, infrastructural, and policy conditions. In addition to identifying economically feasible resources and cost-optimal investment pathways, we also show how the systems could operate for different levels of wind, solar, and battery integration, along with a continuing role for hydropower and natural gas. Such details provide insight and enhanced confidence to system planners, grid managers, and policymakers that it is possible to pursue a low-carbon electricity system through careful investment in clean resources.

5.2. *Favorable future cost conditions for wind and solar may enhance their integration, but this alone is unlikely to avoid heavy reliance on natural gas and an increase in annual GHG emissions*

Our results indicate that more than half of the new sub-regional generation capacity can be contributed by wind and solar under *Reference* conditions, which include moderate declines in the cost of the wind, solar, and battery technologies (consistent with ATB-2019's 'mid' projection [37]). Yet, natural gas constitutes one-third of new capacity due to domestic resource availability and low gas prices in Argentina, Chile, and Brazil. Hydropower expansion is relatively low, as about half of the projected large hydropower capacities in the sub-region appear to be economically unfavorable in the *Reference*. Consequently,

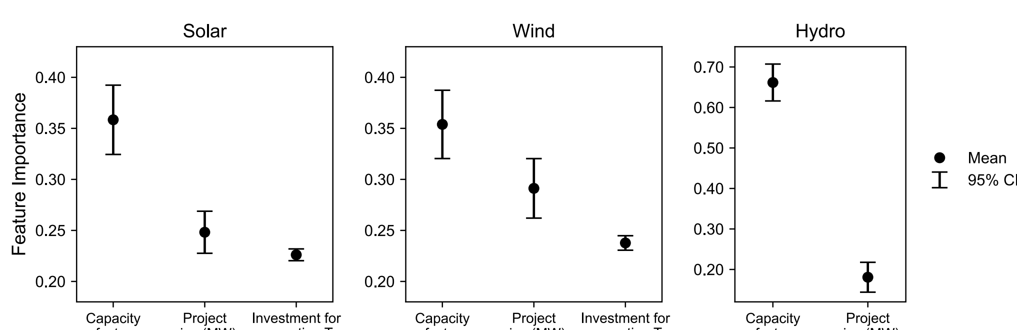

Fig. 8. Comparative influence of annual capacity factor, projected capacity, and distance from existing transmission (Tx) lines (for wind and solar projects only) on economic feasibility of the hydro, wind, and solar projects. The dots and error bars show the mean and 95% confidence intervals (CI) of the feature importance scores of the selected solar, wind, and hydro projects across all scenarios.

the annual GHG emissions of the electricity system could double by 2050 compared to 2020's level. A steeper cost decline (ATB-2019's 'low' projection) in the wind, solar, and battery technologies can enhance their integration, but the annual GHG emissions by mid-century may still increase by 22% relative to 2020. This suggests that the growing cost-competitiveness of wind and solar may provide an important advantage to increasing the share of clean generation, but reducing the heavy reliance on natural gas and limiting annual emissions to at or below the current level will require additional measures such as policy interventions.

5.3. Higher integration of wind, solar, and hydropower can cost-effectively supply the electricity system with low carbon emissions, while protecting against future increases in natural gas prices

An increase in natural gas price by 0.15 USD/MMBtu annually (ATB-2019's 'high' projection), along with a moderate decline in VRE costs, can slightly deter the expansion of gas-based generation capacity, which can be entirely compensated for through higher integration of wind, solar, and hydropower, without installing more polluting (e.g., coal) or expensive (e.g., nuclear, oil) power plants. This would result in only about 10% higher electricity system costs in 2050 compared to the *Reference*, but would also reduce the annual emissions to 28% lower than the current level by 2050.

5.4. The electricity system can sustainably achieve a low-carbon transition by leveraging existing hydro capacity and diversifying future investment in hydro, wind, solar, and battery storage

For transition towards net zero emissions by 2050 or earlier, the countries in our study sub-region may require deep decarbonization of the electricity system, given that reducing emissions from other sectors (e.g., agriculture) can be quite challenging [30]. Keeping this in mind, we investigated pathways for reducing the annual emissions in 2050 by at least 90% of the current level. Our results indicate that the low-carbon transition will primarily depend on higher integration of wind and solar power. To achieve 90% emission reduction, the sub-region may require accelerating the new wind and solar power deployment rate to 8–12 GW and 5 GW per year, respectively, which are about two times higher than the respective rates in the *Reference*. While VRE deployment rates are already impressive in the sub-region (e.g., Brazil's average wind deployment rate is 2 GW per year over the last decade [6]), more than half of the total new wind and solar capacities in our low-carbon scenarios are cost-optimally selected after 2040, which may allow sufficient lead time for structural and non-structural preparation to accelerate their integration. A small amount of utility-scale battery storage may also be required only after 2040 because the existing high supply of hydropower can complement the solar and wind supplies in hourly electricity dispatch in both dry and wet seasons.

The existing hydropower also appears to be critically important to maintaining a low-cost and low-carbon electricity system in the future, as retiring installed hydropower earlier than anticipated (60 years instead of 100 years) may require the system to rely on more expensive and/or polluting resources (e.g., natural gas, diesel). The generation of existing hydropower dams can be sustained by a wide range of efforts, including paying close attention to sediment management, monitoring how climate change is altering reservoir inflows, and developing adaptive operating policies.

Our results also indicate that an adequate combination of hydro-wind-solar-battery resources may ensure a reliable low-carbon electricity supply at a lower cost than a more wind-solar-battery dominated system. This is because diversifying investment in hydro and VRE resources may require fewer new capacities and less curtailment and transmission losses compared to a VRE-dominated investment. However, an enhanced hydropower deployment may lead to extensive exploitation of the resources in some river basins, including the Amazon and La Plata, which may cause serious socio-environmental and biodiversity impacts [73]. Given the widespread availability of high-quality wind and solar sites across the sub-region, hydropower projects with potential externalities may be replaced by wind and solar. Similarly, wind and solar projects with potential conflict with protected areas and other land use may be replaced with carefully-selected low-impact hydropower projects. Our results also indicate that investments in wind and solar projects with high production potential but located at a greater distance from existing transmission networks can still be beneficial. Overall, we conclude that the sub-region has tangible opportunities to pursue a low-carbon transition by careful investment in hydro, wind, solar, and battery projects. Our finding is consistent with other studies [2,36] that suggested enhanced integration of clean resources globally is a viable solution to climate change and energy insecurity.

5.5. Enhanced regional electricity trade can significantly benefit the low-carbon transition, and is achievable with nominal investment in interconnection lines

Low-carbon transition with higher integration of wind and solar resources can be facilitated by enhanced sub-regional electricity trade. Up until 2040, sub-regional trade may slightly decline due to the availability of sufficient economically feasible domestic clean energy resources in each country. However, after 2040, sub-regional trade could rebound to 2-5 times higher than 2020's level, primarily comprised of export from Argentina to Brazil and Chile as certain wind projects in Argentina could be more cost-competitive to expand than some of the VRE projects in Brazil and Chile. This trade can be facilitated by up to 13 GW and 17 GW of new transmission capacities in cross-border lines from Argentina to Brazil and Chile, respectively, which are 12 and 34 times higher than their existing transfer limits. However, the majority of the new transmission capacities would be required after 2040, allowing sufficient lead time. Nevertheless, the investment costs for new interconnection lines are not more than 3% of the total investment and operating costs for the electricity system. Therefore, the enhancement of sub-regional trade may largely depend on geopolitical coordination. Since the countries are already part of an economic trade bloc (MERCOSUR), enhanced sub-regional coordination might be plausible.

5.6. Limitations and future work

While we incorporated a wide range of techno-economic, infrastructural, and policy influences in our model framework and scenarios, we did not consider several important aspects which may also critically influence the development of the electricity systems. First, we did not consider potential climate change impacts on the electricity demand and supply resources. However, previous studies indicated that climate change could reduce hydropower production [74], while increasing wind production [21], in the South America region. Thus, climate change may increase the integration of wind in the electricity system, which is consistent with our conclusions. Also, while we used single-year data on the wind and solar capacity factors based on a reanalysis climate forcing, future works can investigate the effects of inter-annual variability of wind and solar power availability, and so of the errors in the reanalysis data. However, in our analysis, we ensured dispatchable power (including battery storage) will be available in case of a prolonged gap in variable renewable resource availability by applying a 15% planning reserve margin with 80% effective load-carrying capacity for dispatchable power plants and storage but only 10% for wind and zero for solar resources. Second, we modeled the five-country electricity system as a closed system with full coordination. While enhanced sub-regional coordination may be plausible, any of these five countries may also extend electricity trade with other countries in the South America region. Yet, since our scenarios indicate that the countries may largely depend on the expansion of domestic clean energy resources, at least until 2040, a wider regional trade assumption may not significantly alter our key conclusions. Moreover, geopolitics and governance could play a significant role in the evolution of the power systems and associated trades, which is beyond the scope of this study. Third, we projected future electricity demand under historical socioeconomic growth, and did not consider the effects of other potential forces (such as rapid socioeconomic changes, end-use electrification, and energy efficiency) which could affect the future demand and associated development of the electricity system. Fourth, while we discussed the opportunity for complementing one type of renewable project with another type to limit socio-environmental impacts, further investigation is necessary to explicitly incorporate potential socio-environmental impacts of the candidate renewable projects in the investment decisions, which we aim to address in our future work. Nevertheless, these influences can be explored in relevant future studies. Future studies should also consider exploring the multi-sector dynamics interactions among energy, water, and land systems to identify how factors such as water scarcity [79], land use change [80,81], and enhanced electrification [82] in the region could influence the future evolution of the electricity system.

CRediT authorship contribution statement

A.F.M. Kamal Chowdhury: Conceptualization, Methodology, Model framework, Data curation, Formal analysis, Writing – review & editing. **Jacob Wessel:** Data curation, Formal analysis, Writing – review & editing. **Thomas Wild:** Conceptualization, Funding acquisition, Writing – review & editing, Supervision. **Jonathan Lamontagne:** Funding acquisition, Writing – review & editing, Supervision. **Franklyn Kanyako:** Data curation, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data used in this study are available at Zenodo (DOI: https://doi.org/10.5281/zenodo.7110358).

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.esr.2023.101150.

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