

Article

100% Renewable Energy Scenarios for North America—Spatial Distribution and Network Constraints

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Abstract: The urgency to combat climate change and the widely distributed, increasingly competitive renewable resources in North America are strong arguments to explore scenarios for a renewable energy supply in the region. While the current power system of North America is heavily dependent on fossil fuels, namely natural gas, coal and oil, and some nuclear power plants, some current policies at the state level, and future federal policies are likely to push the share of different renewable sources available in Mexico, the U.S., and Canada. This paper explores three scenarios for a renewable energy supply, using a bottom-up energy system model with a high level of spatial and time granularity. The scenarios span the extremes with respect to connecting infrastructure: while one scenario only looks at state-level supply and demand, without interconnections, the other extreme scenario allows cross-continental network investments. The model results indicate that the North American continent (a) has sufficient renewable potential to satisfy its energy demand with renewables, independent of the underlying grid assumption, (b) solar generation dominates the generation mix as the least-cost option under given renewable resource availability and (c) simultaneous planning of generation and transmission capacity expansion does not result in high grid investments, but the necessary flexibility to integrate intermittent renewable generation is rather provided by the existing grid in combination with short-term and seasonal storages.

Keywords: 100 percent renewable energies; capacity expansion modeling; electricity market integration



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1. Introduction

Shortly before political leaders from all over the world gathered for the Copenhagen Summit in 2009, Jacobson and Delucchi [1] published an article with a roadmap towards a worldwide, 100 percent renewable energy system by 2030. Although the overall capacity of Renewable Energies (RE) has been gradually increasing and several countries have committed to ambitious climate targets since then, today's total energy supply is still primarily met by fossil fuels and the world is facing a prevailing, massive emission gap in reaching the Paris Climate agreement [2,3]. As the current scientific and public debate discusses several mitigation options for the energy sector, the recent scientific research on a large-scale deployment of RE suggests that RE are becoming more cost-efficient than electricity generation from fossil fuels, even without including the social cost of carbon emissions and including the intermittent nature of RE [4].

With a share of approximately one-fifth of the global primary energy demand, North America is the second-largest consumer and producer of energy in the world [5]. As illustrated in Figure 1, the electricity generation in the United States (U.S.) and Mexico still depends mainly on fossil gas, coal, and nuclear power, while Canada already utilizes its potential for hydro generation. However, the framework for power generation is gradually changing towards increasing shares of RE, as in the recent Clean Power Plan announced by

the upcoming Biden administration or California's target to reach 100 percent renewable electricity generation by 2045. Simultaneously, costs for technologies based on RE and storage costs to provide the necessary flexibility are rapidly declining, most notably in the case of solar Photovoltaics (PV). Consequently, there is growing research regarding power systems based on 100 percent RE.

Regional and cross-national electricity trade alongside the required physical infrastructure plays a major role in the process of decarbonization and the transformation of the energy system. In particular with regards to North America's rich and diverse potential for RE, electricity market integration is discussed as another flexibility option to integrate intermittent RE generation. While power system integration in between Canada and the U.S. is practiced already (see Figure 1), there is no relevant electricity trade between Mexico and the U.S. and the existing capacities are predominantly used for voltage and frequency stabilization [6].

In this context, infrastructure does not only provide the framework for the participation of the private sector but is in the case of electricity infrastructure also a long-term investment that creates path dependencies for several decades. Risks and benefits of such investments need to be carefully assessed and several future developments that influence and are influenced by infrastructure need to be considered. Therefore, a large and growing body of scientific literature deals with the role of electricity grid expansion for the decarbonization of energy systems all over the world. However, while many models and publications provide valuable insights for grid expansion based on data in very high spatial and temporal resolution, few models examine grid expansion on a large-scale and most models still include fossil and fissile generation technologies. Due to the unconsidered external effects of fossil fuels and the dangers of nuclear power as well as the lacking of a solution for the disposal of the accompanying nuclear waste, scenarios that do not include these technologies need to be evaluated to create a diverse set of options for political decision-makers. Under given environmental, socio-economic, and political circumstances, there is hence a need for exploring potential futures of a power system based on 100 percent RE that benefits from considering the whole North American continent instead of relying on national perspectives.

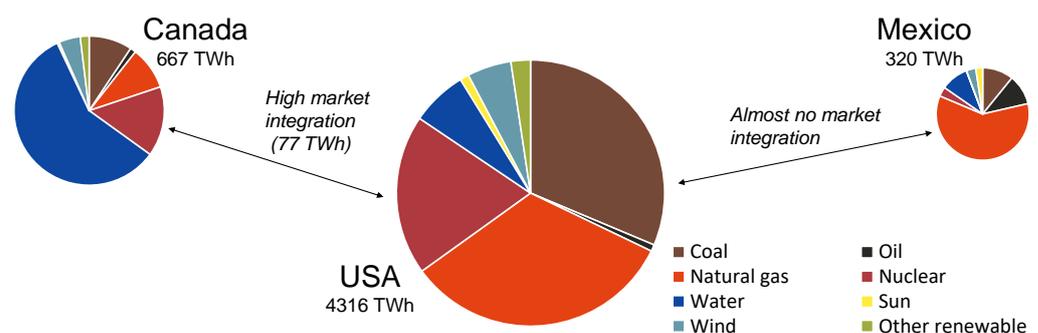


Figure 1. 2018 generation mix and electricity exchange in North America. Note that the diagram size only qualitatively illustrates the overall national generation. Own illustration based on data from International Energy Agency (IEA) [2].

To assess and quantify these futures, a greenfield least-cost capacity expansion model is applied, using technology cost assumptions for 2050. It is implemented in the AnyMOD Framework [7,8] with spatially disaggregated data for renewable potentials and availability time series in a high temporal resolution in combination with data on the current infrastructure for electricity and gas trade. Three scenarios with differing underlying grid assumptions are analyzed to draft and quantify a vision of a future North American power system based only on RE. Main questions that are attempted to be answered through the scenario-based model approach are firstly, what is the most cost-efficient distribution of RE

generation under consideration of the whole North American continent and secondly, how is this distribution influenced by the underlying energy transmission infrastructure.

Key findings include an assessment of the dimensions in terms of generation and storage capacity as well as the strong role of solar generation in combination with short- and long-term storage capacities, resembling the results of former studies [9,10]. High investments in transmission grid infrastructure to provide high levels of spatial flexibility are not endogenously chosen when generation and transmission capacity expansion is planned simultaneously, but rather limited to minor expansions at the U.S.-Mexican border and a major expansion to supply the high load area of the PJM Interconnection.

This paper is structured in the following way: The next section includes a review of relevant literature for both energy system modeling with 100 percent RE and grid expansion models, covering the whole or parts of the North American continent. The AnyMOD framework is described in Section 3, followed by the underlying input data in Section 4. Section 5 contains a description of the scenario storylines and Section 6 presents the main model results in terms of generation, storage, and energy exchange. The model results and their limitations are discussed in Section 7. Finally, Section 8 concludes.

2. Literature Review

Relevant modeling literature for this paper can roughly be structured along two axes. First, literature that models an energy supply based on 100 percent RE without an explicit focus on grid representation and second, literature focusing transmission infrastructure expansion but modeling energy supplies not fully based on RE. In the following, both categories are limited to literature within the geographical scope of North America, but in different spatial and temporal resolutions.

2.1. 100 Percent Renewable Energies in North America

There has been a growing body of scientific publications in the design of 100 percent RE energy systems since Jacobson and Delucchi [1] published their article in 2009 [4]. Several studies address 100 percent RE in different spatial and temporal resolutions within North America: Jacobson et al. [9] model pathways to convert the energy infrastructure of all sectors in 50 United States to a system based solely on wind, water, and sunlight (WWS) resources by 2050, supported by a grid integration study addressing the grid reliability issue of intermittent RE generation [11]. The resulting generation mainly consists of onshore and offshore wind generation as well as utility-scale photovoltaics. Similar studies have been carried out for 53 towns and cities in North America [12], Washington State [13], New York State [14] and California [15]. Even before this stream of 100 percent renewable research, Ken Zweibel and colleagues [16] provided a blueprint for sustainable electricity development based mainly on solar energy, the so-called Grand Solar Plan. Aghahosseini et al. [10] model a cost-optimal power supply for North America in an hourly temporal resolution based on 100 percent RE under different electricity transmission assumptions for 2030. The paper estimates the impacts of High-Voltage-Direct-Current (HVDC) transmission lines on RE generation and storage capacity. Throughout all scenarios, the predominant role of solar PV and wind generation is confirmed. Key findings include the cost-optimal, regional distribution of RE in a scenario based on high HVDC interconnection as well as the trade-off between generation and storage capacity and transmission grid infrastructure. Using a similar approach, Aghahosseini et al. [17] model an energy system based on 100 percent RE for the Americas in 2030 to evaluate the benefits of energy system integration on an even broader scale. The results of the study resemble the results of the former study with an almost evenly distributed share of solar PV and wind generation across the considered regions. Both studies conclude that a 100 percent RE energy system is feasible and more cost-effective than the current power system based on fossil fuels, even without taking emission costs into account. The latter study also includes a comprehensive review of 100 percent RE studies in the Americas. Most recently, Dowling et al. [18] use long-range weather data to evaluate the role of Long-Duration Storages (LDS) in electricity systems

with only wind and solar generation and conclude that LDS have great potential to provide the necessary flexibility and to reduce the costs of future variable renewable electricity systems. The Los Angeles 100% Renewable Energy Study by the National Renewable Energy Laboratory (NREL) is scheduled for 2021 and is expected to provide insights in pathways to a 100 percent RE supply by 2045 [19].

2.2. Capacity and Transmission Grid Planning Across North America

A frequently employed capacity expansion model for the U.S. electric power sector is the Regional Energy Deployment System (ReEDS), developed by the NREL for simulating electricity sector investment decisions with high shares of renewable energy [20]. The model relies on system-wide least-cost optimization to estimate the type and location of future generation and transmission capacity. Using ReEDS, Ibanez and Zinaman [21] model the influence of several drivers on the combined capacity expansion of the U.S.-Canadian electricity sector to demonstrate the capabilities of a single planning model for both countries. Building on this work, Beiter et al. [22] examine the value of U.S.-Canadian grid integration by modeling the integrated capacity expansion under both restricted and unrestricted cross-border transmission capacity. While both studies discuss and analyze the trade-off between national investments in generation capacity and transmission grid investments, significant cross-border transmission grid expansion between the two countries is calculated as cost-optimal. Ho et al. [23] provides a documentation of the application of ReEDS to the Mexican power sector as well as a sensitivity analysis of demand assumptions on renewable capacity expansion. The recent Interconnections Seam Study deploys ReEDS to estimate the potential economic benefit of adding HVDC transmission lines between the Eastern and Western Interconnection of the U.S., indicating a significant added value of increased transmission infrastructure [24]. Brown and Botterud [25] support these results by analyzing zero-carbon pathways for the U.S. power system based on technologies that are already available at gigawatt-scale, including approx. 20 percent of nuclear energy. They find that transmission infrastructure expansion across the U.S. and national generation capacity planning significantly reduces the cost of decarbonized electricity. Sarmiento et al. [26] simulate the influence of different climate policies on the structure of the Mexican energy sector, using a numerical capacity expansion model. Main conclusions include relatively high shares of cost-optimal RE-shares with a strong role of solar PV, while existing climate policies are considered as insufficient to foster a cost-efficient energy system. Considering the whole North American continent, the North American Renewable Integration Study (NARIS), currently conducted by NREL, is a large-scale analysis to identify potential cooperation between Mexico, Canada and the U.S. in different power system futures with growing shares of RE [27]. Finally, a recent Energy Modeling Forum (EMF 34) on North American Energy Trade and Integration studied the integration and collaboration potentials within the three countries' energy system futures. Huntington et al. [28] provide an overview of the study, including the scenarios and participating modeling teams. As a subgroup outcome of the modeling forum, Bistline et al. [29] evaluate the impacts of renewable policy coordination across North America, finding that transmission infrastructure investments are highest in the scenario with international coordination of renewable policy.

While there is already existing literature in both categories, few studies are combining both approaches. This paper hence aims at filling this gap by providing a starting point for capacity and transmission infrastructure planning in a power system based on 100 percent RE. The explicit grid representation as well as the high temporal resolution furthermore enables a detailed representation of long- and short-term storages.

3. Methodology

To evaluate the role of the power grid in a fully renewable system, we deploy a cost-minimizing capacity expansion model created with the AnyMOD framework [7,8]. The model takes a greenfield approach focusing on a single snapshot year. For each of the modeled regions, as displayed in Section 4, the model determines investment into power

generation and storage to satisfy an exogenously set demand. The linear minimization of costs deployed is the most common approach for the techno-economic modelling of energy systems.

Figure 2 provides an overview of the technologies and energy carriers considered in the model. In the graph, carriers are symbolized by colored squares and technologies by gray circles. Edges between technologies and carriers indicate their relation and entering edges of technologies refer to input carriers; outgoing edges refer to outputs. For example, CCGT (combine cycle gas turbine) plants either take synthetic gas or hydrogen as an input to generate electricity. Edges between carriers indicate that they are interchangeable in some contexts. Hydrogen and synthetic gas for instance can both be shared by gas storages, because they of outgoing edges directed to the carrier 'gas'. Accordingly, the model considers solar, wind, hydro, biomass for power generation, while pumped storage and batteries are available for short-term storage of electricity. Seasonal-storage is not included as another technology, but by explicitly including the technologies that can generate, store and re-fuel electricity-based energy carriers like hydrogen or synthetic gas: Hydrogen is created from electrolysis and can be directly refueled using combined-cycle hydrogen plants or used as an input for methanation to create synthetic gas. Synthetic gas can again be refueled by conventional combined-cycle plants and both carriers can be stored by dedicated storage systems.

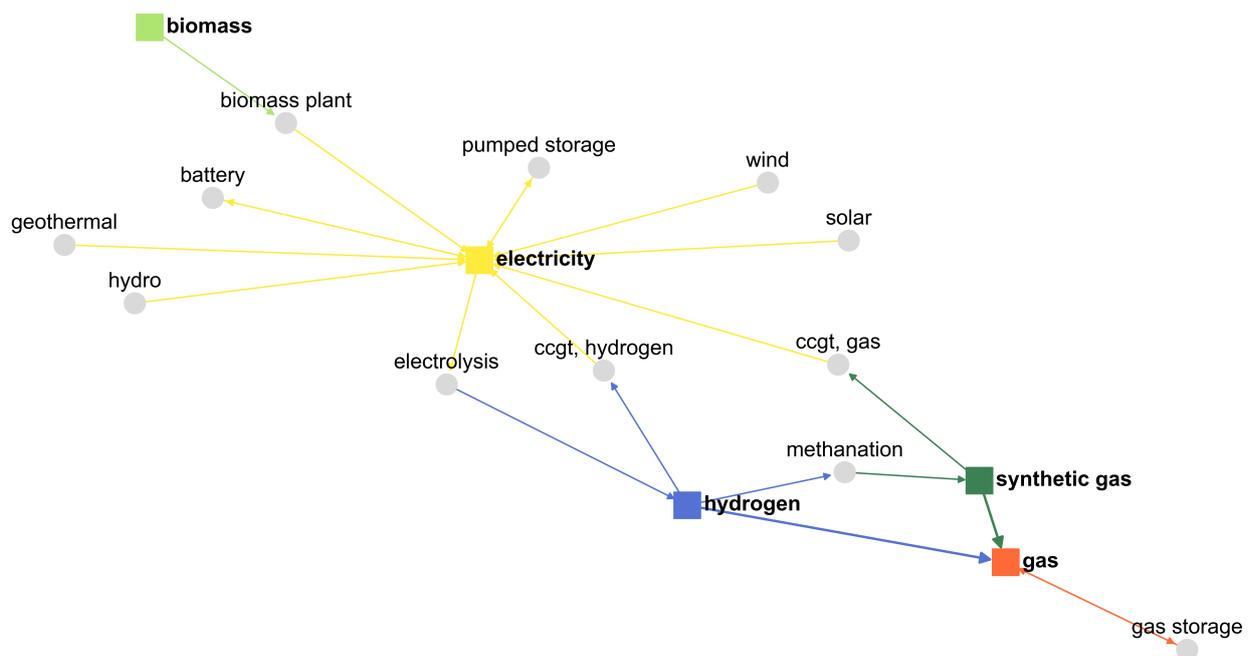


Figure 2. Overview of modeled energy carriers and technologies within the AnyMOD Framework. Carriers are symbolized by colored squares and technologies by gray circles.

In addition to technology investment, the model is also capable to determine investment into the transmission grid to exchange electricity between the 25 modeled regions. For this purpose, the actual transmission grid is aggregated according to the 25 considered sub-regions and modeled as a transport problem neglecting loop flows.

To capture the fluctuating nature of generation from intermittent renewables, like wind or solar, the model applies an hourly resolution of 8760 steps for all electricity-related variables. The gaseous energy carriers hydrogen and synthetic gas are instead modeled at a daily resolution to reduce the computational effort and account for the inherent flexibility these carriers provide.

4. Data

Relevant input data used within the AnyMOD framework is structured in the underlying network assumptions, renewable resource availability and technologies that are considered to supply the electricity demand on an hourly level.

4.1. Network

The North American power system is considered as a simplified 25-node-network as depicted in Figure 3, excluding Alaska, Hawaii, and the Northern Canadian regions. The zonal distribution of the contiguous U.S. is based on the regional distribution of the electric power regions, the three Canadian zones follow the major Interconnections of the North American power system and the Mexican zones are defined according to the national control regions [30]. Table A1 provides detailed information on the nodal distribution. The Net Transfer Capacity (NTC) represents upper limits to the amount of energy that can be traded between nodes. The existing NTC for electricity and gas trade are illustrated in Figure 3, where link weights represent the trade capacity in gigawatt (GW). Data for the NTC inside the U.S. is derived from ReEDS [20,31]. Cross-border infrastructure for electricity and gas is based on data from U.S. Energy Information Administration (EIA) [32]. Capacities are given in voltage and million standard cubic feet per day, respectively, and are transformed into trade capacities in gigawatt (GW). Data on electric transmission infrastructure for Mexico is taken from Secretaria de Energía (SENER) [30]. Transmission capacity between the Canadian regions is assumed to be zero. Grid expansion costs as well as transportation losses are calculated based on the nodal distance and are considered according to Carlsson et al. [33] and Neumann et al. [34] respectively. Table A5 provides an overview on all relevant parameters.

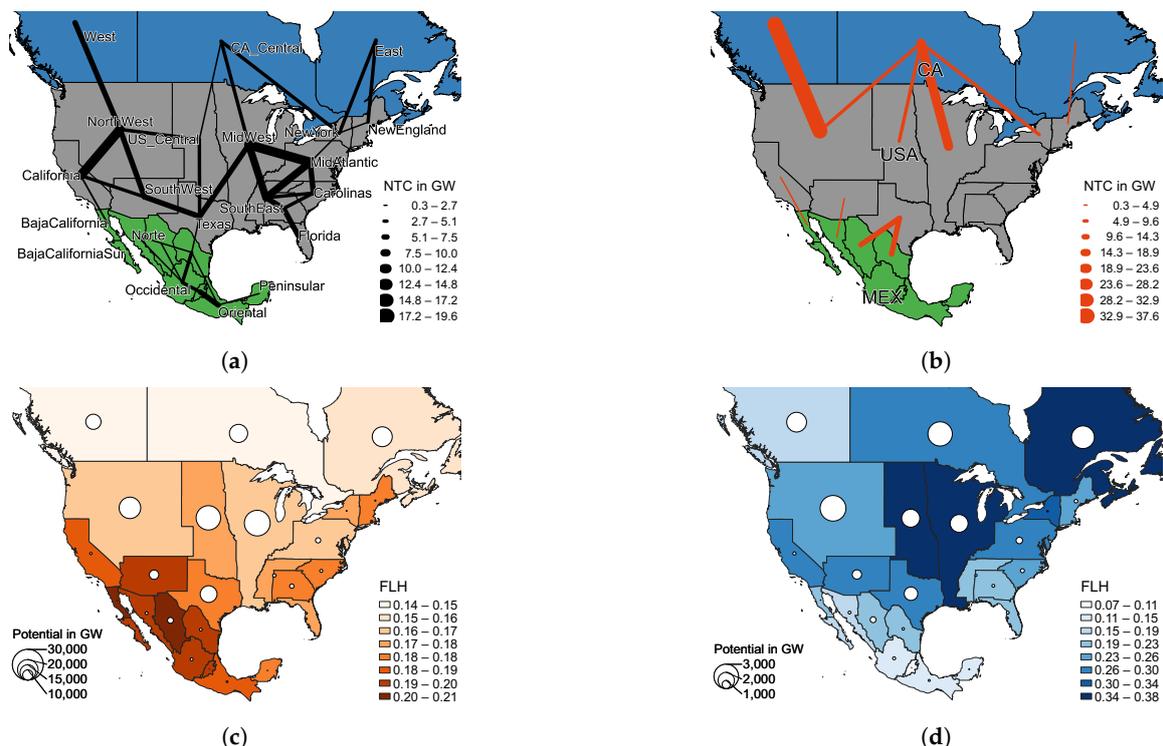


Figure 3. Underlying input data. (a,b): Nodal distribution and trade restrictions for electricity (a) and gas (b). Link weights represent the NTC (Net transfer capacities) in GW. Own illustration based on data from EIA, ReEDS and SENER [30–32]. (c,d): Nodal distribution of renewable potential for solar (c) and wind (d). Nodal shades represent the average FLH (full load hours). The darker the shade, the higher the resource availability. Own illustration based on external data [20,35,36].

4.2. Renewable Resources

The spatially and temporally intermittent availability of wind and solar resources is modeled using hourly time series for wind and solar generation [35,36]. The time series are obtained in a regional resolution of 200km and aggregated at a nodal level. The full load hours (FLH) based on the regional time series serve as a measure for the average availability of an intermittent resource and are illustrated in Figure 3. Technologies based on geothermal and hydro energy are assumed to be dispatchable. Investment in renewable technologies is limited to renewable potentials, e.g. due to land availability. All renewable potentials are derived from ReEDS [20]. The nodal distribution of renewable potentials in GW for wind and solar is depicted in Figure 3. The total potential amounts to 187,000 GW for solar, 24,000 GW for wind, 267 GW for hydro and 3400 GW for geothermal resources, including deep enhanced geothermal systems. A detailed description of potentials can be found in Brown et al. [31] and assumptions of similar magnitude are also made in other studies [10]. The potential for biomass generation is based on data from Aghahosseini et al. [10]. A comprehensive overview of the availability of renewable resources in the U.S. can be found in NREL's Renewable Energy Atlas [37].

4.3. Technologies and Demand

Investment in conversion technologies is limited to technologies based on renewable resources, as depicted in Figure 2. A detailed overview of the assumed investment and operating costs for conversion and storage technologies can be found in Tables A2 and A3 respectively. Efficiency losses occur when carriers are converted or stored. Table A4 lists the efficiency of all carrier conversion and storage technologies. Electricity demand is provided in an hourly resolution for each node. Demand time series for the U.S. are obtained from the EIA [38]. Due to limited data availability, the demand time series from the Alberta Transmission System Operator is scaled according to the population of each Canadian state [39]. For Mexico, demand data is derived from SENER [30].

5. Scenarios

A least-cost investment in generation capacity is calculated in three scenarios to assess a zero-carbon and zero-nuclear-waste future based on 100 percent RE for 2050. Since investment decisions, especially in transmission grid infrastructure, are taken from a long-term perspective the scenarios contribute to evaluating different pathways of distributed generation capacity based on different infrastructure constraints. Throughout all scenarios, the same investment and operating cost assumptions are implied for the respective energy storage and generation technologies. Modeled spatial and temporal flexibility options to ensure grid reliability include the electricity and gas network as well as short-term and seasonal storage technologies. A special focus lies hence in the high spatial and temporal resolution of RE availability.

5.1. No Expansion [FIX]

Optimal investments in generation and storage capacities at each node without transmission grid expansion is modeled in scenario *FIX*. Energy exchange is only allowed using existing trade capacities. Maximum electricity generation inside each region is limited by renewable potentials, while the current North American electricity and gas grid limits inter-nodal energy transfer. Losses for energy storage and transportation are considered as outlined in Section 4.

5.2. Endogenous Expansion [EXP]

In this scenario, the model can extend the existing grid to exploit the best renewable resources, considered by spatially and temporally disaggregated data on RE potentials and time series. Investment costs of transmission grid expansion between the zones are taken into account based on their length, as explained in Section 4. Hence a cost-optimal allocation of RE resources is modeled since investments in generation capacity and grid

expansion are made simultaneously. There is no endogenous expansion of existing trade capacity for gas exchange.

5.3. Decentralized Infrastructure [DEC]

While the scenarios *FIX* and *EXP* are focusing on the impact of grid utilization and expansion, the third scenario explores the role of the electricity and gas network as a flexibility option and to what extent storages can replace this flexibility. In scenario *DEC*, nodal energy demand is therefore solely met by resources located at the same node and all energy exchange is suppressed. Flexibility options are limited to storages and investments in dispatchable technologies. The scenario aims to analyze the trade-off between potentially higher investment costs for decentral, near-consumer power generation compared to transmission infrastructure costs occurring in a more interconnected power system.

6. Results

Results are discussed structured in generation, storages and exchange.

6.1. Generation

Figure 4 illustrates the regional distribution of electricity generation for scenarios *EXP* and *DEC*. The detailed regional generation results from scenario *FIX* are highly similar to scenario *EXP* and are therefore not depicted, indicating that transmission grid expansion does not have a strong impact on the spatial allocation of RE generation. This is further discussed in Section 6.3. Solar generation is favored throughout all scenarios and dominates the generation mix with an overall generation of 4141 terawatt hours (TWh) in *EXP* and 4073 TWh in *DEC*, followed by wind generation with 839 TWh in *EXP* and 819 TWh in *DEC*. Hydro generation accounts for 490 TWh in *EXP* and 475 TWh in *DEC*. Geothermal generation benefits in the *DEC* scenario, with about 300 TWh, against the infrastructure extension scenarios (approx. 220 TWh).

Enabling electricity exchange in the integrated scenarios leads not only to a technological generation shift, but also to a regional generation shift. In both integrated scenarios, cost-optimal solar and wind resources are exploited. Nodes with a high solar availability, such as California, Texas or New York in the U.S., and Oriental in Mexico become net exporters of electricity and supply neighboring regions. Regions with the highest wind availability are mostly located in central U.S. and Eastern Canada (see average full load hours (FLH) in Figure 3) and increase their generation in the integrated scenarios.

6.2. Storages

The model results underline the importance of short-term and seasonal electricity storages in a 100 percent RE power system. Overall installed storage power roughly varies between 780 GW and 855 GW and overall installed storage capacity between 188 TWh and 300 TWh in between scenarios *EXP/FIX* and scenario *DEC*, respectively. Analogous to electricity generation, storage demand is not strongly affected by transmission grid expansion (see Table 1 for detailed results). The regional distribution of installed short-term battery storage power for all scenarios is depicted in Figure 5 and illustrates the link between high solar generation and storage demand, but also the trade-off between storage capacity and electricity exchange for power systems with high shares of intermittent RE. In the integrated scenarios, nodes with high solar generation, such as California and Oriental, have high installed storage power and nodes with high wind generation, such as central U.S. and MidWest, have a minor storage demand. In nodes with high load, installed storage power more than doubles in the decentralized scenario. Dispatchable geothermal or hydro resources are likely to reduce the necessity for storage. Figure 5c shows the installed storage capacities by technology, aggregated by country and scenario. While the installed capacity for batteries does not significantly vary between the scenarios, the installed capacity for seasonal hydrogen storages strongly increases in the decentralized scenario in all countries.

In the decentralized scenario, electricity exchange is replaced by storages in regions with high load, such as MidAtlantic or MidWest in the U.S. and Mexico City.

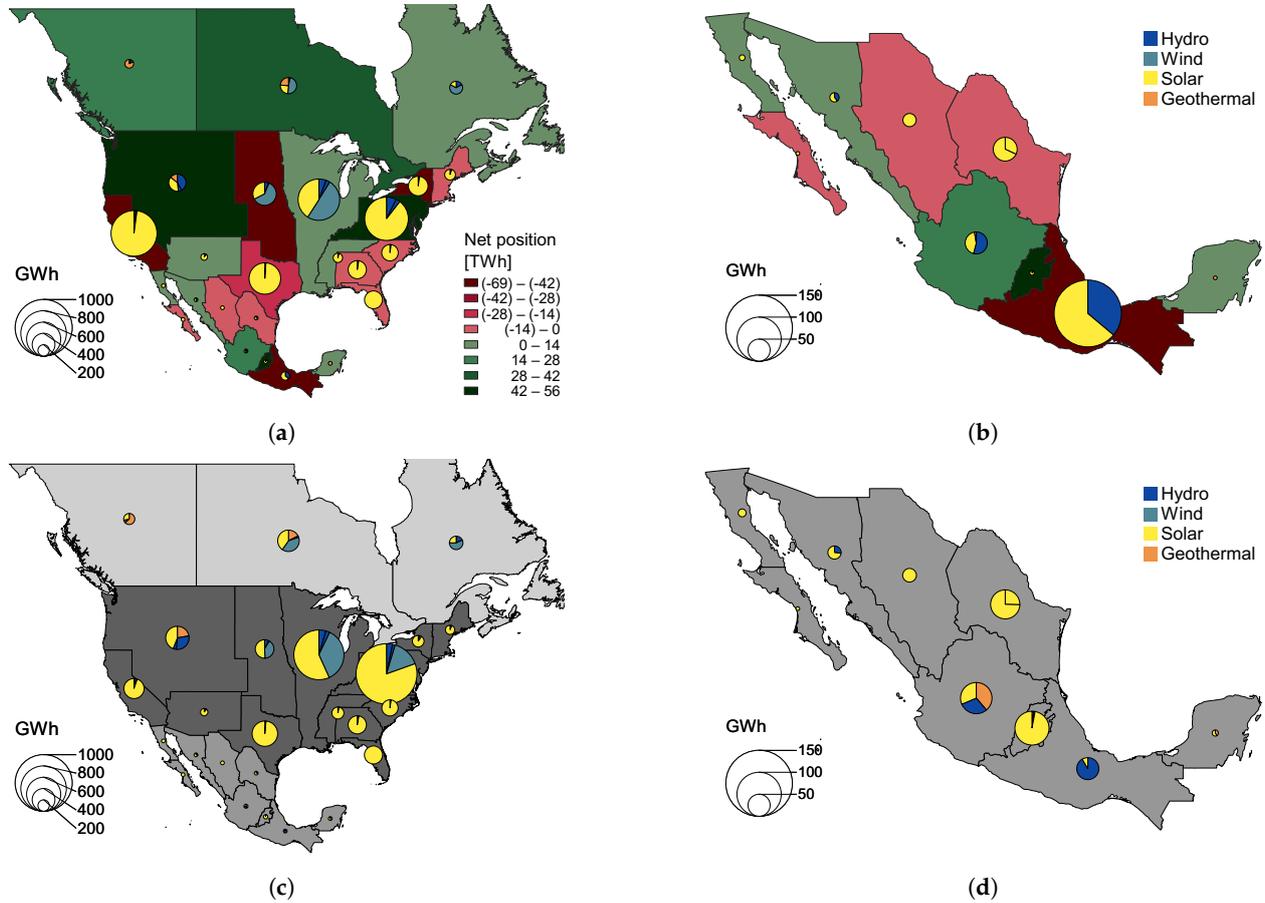


Figure 4. Generation results in gigawatt hours (GWh). (a,b): Regional electricity generation mix for all nodes (a) and the Mexican nodes (b) in scenario EXP. Nodal shade represents the net position of electricity trade in TWh. Green nodes are net importers, red nodes are net exporters. (c,d): Regional electricity generation mix for all nodes (a) and the Mexican nodes (b) in scenario DEC. Net position is zero, since there is no energy exchange in this scenario. Own illustration based on model results.

Table 1. Model results.

Scenario	Installed Generation Capacity	Installed Storage Power	Installed Storage Size	Total Electricity Generation	Grid Expansion Cost	Total Cost
Unit	GW	GW	TWh	TWh	Mil. USD	Mil. USD
DEC	3347	855	299	5667	0	221,168
FIX	3235	774	187	5708	0	208,809
EXP	3218	780	187	5691	702	208,617

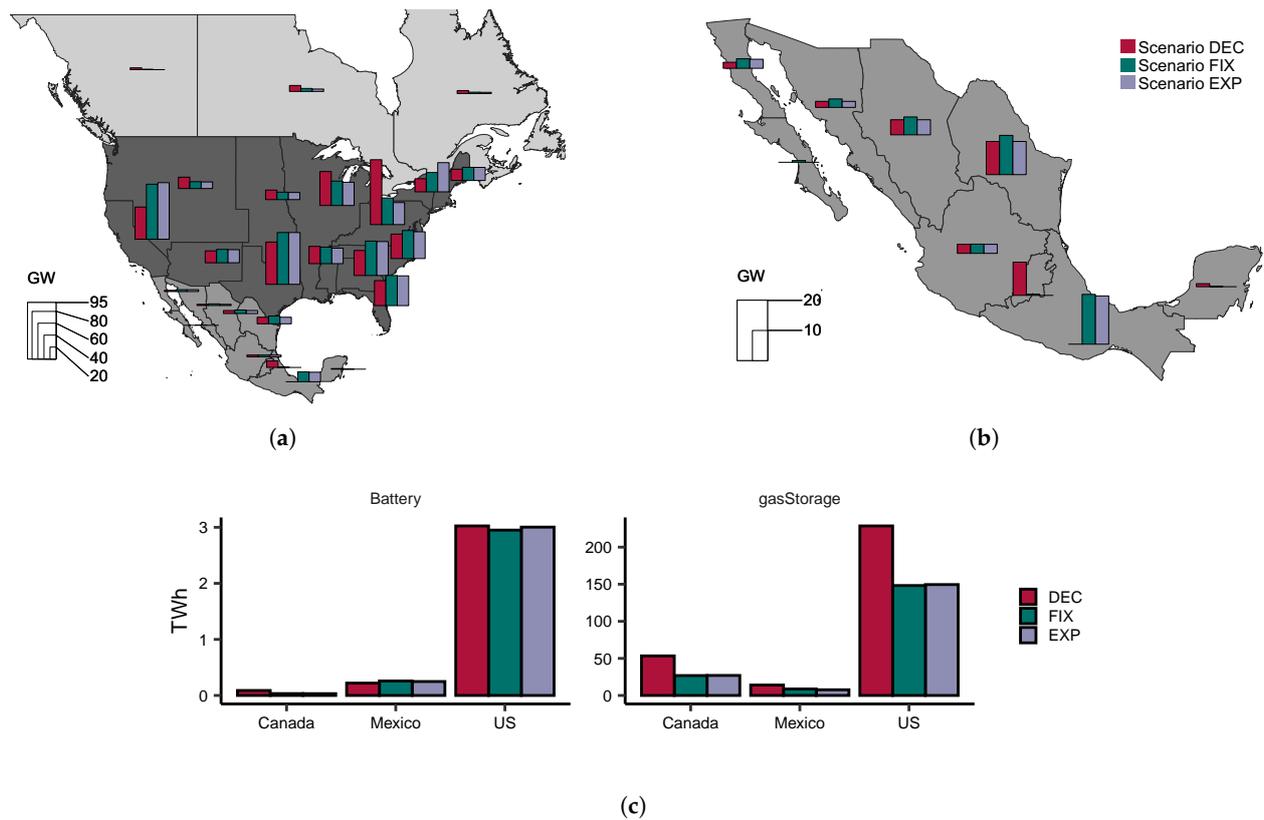


Figure 5. Storage results. (a,b): Regional storage power for all nodes (a) and the Mexican nodes (b) in GW by scenario. (c): Aggregated storage capacities in TWh by scenario. Note the different axis scales Own illustration based on model results.

6.3. Exchange

Figure 6 shows the endogenous transmission capacity expansion that was modeled in scenario *EXP*. Interestingly, transmission expansion does not play a major role in the scenarios, and it seems to be no binding constraint for the deployment of renewables. Model results suggest minor expansions between New York and MidAtlantic (approx. 9 GW), likely to exploit the higher availability of solar resources there to supply the high load of MidAtlantic. Smaller cross-border capacity expansions are added between Texas and Norte in Mexico (1 GW) and SouthWest and NorOeste (0.2 GW), as well as between BajaCalifornia and NorOeste inside Mexico (1.5 GW). Clearly an increased cross-border integration results in overall efficiency gains. However, the results of other studies regarding transmission capacity expansion, which find major transmission capacity additions in the U.S. to be cost-optimal, are not resembled here [24,25]. Also, investments in a highly interconnected grid, as it is assumed in the integrated scenario in Aghahosseini et al. [10] to allocate the best renewable resources and provide flexibility for intermittent renewable generation are not chosen as a cost-effective solution. As displayed in Figure 4, existing trade capacities are utilized but not strongly expanded. Further cross-border integration between the U.S. and Canada, as examined in other studies, is also not reflected in the applied greenfield RE approach [21,22]. Figure 6 displays the net exchange between the U.S. and its neighboring countries. In both scenarios, the U.S. is a net exporter of electricity and hydrogen to Canada. Exports to Mexico increase in scenario *EXP*, likely due to the added trade capacities. In both scenarios, Mexico is a net exporter of hydrogen to the U.S.

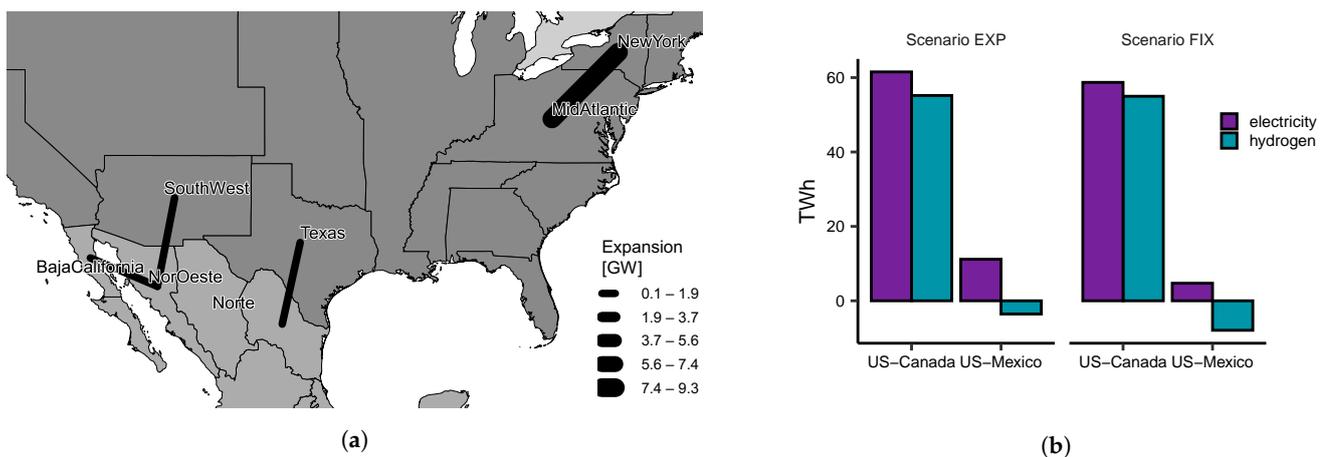


Figure 6. Exchange results. (a): NTC expansion in GW in scenario *EXP*. (b): Net exchange between North American countries in TWh by carrier in scenarios *EXP* and *FIX*. Own illustration based on model results.

6.4. Summary

The scenarios *DEC*, *FIX* and *EXP* determined investments in a least-cost renewable generation mix for 2050. Key comparative metrics are listed in Table 1. While the overall installed generation and storage capacity is highest in scenario *DEC*, total electricity generation is highest in scenario *FIX*. Since the demand time series is the same for all scenarios, differences in total generation originate from transportation, carrier conversion and storage losses. Total cost for a decentralized power system are highest. However, since costs for the existing infrastructure is not considered, total costs between scenario *DEC* and *FIX/EXP* are difficult to compare. Figure A1 provides a further overview on the aggregated installed capacities of all energy conversion and storage technologies.

7. Discussion

The presented model results can only provide a first step in future research that needs to be conducted to design a reliable and renewable energy system. They need to be interpreted as a techno-economic perspective, drafting an economically efficient power system that respects certain physical constraints, but also constitutes a materialistic view focused on a linear optimization of energy flows. Other relevant perspectives are neglected, such as behavioral patterns or the political economy of RE. Since the transformation of the energy system is a highly complex process, any technological choice is inherently intertwined with social structures, actors and institutions. Holistic research hence needs to undertake an interdisciplinary approach, including a variety of methods from different scientific disciplines. Challenges that need to be addressed include for instance incumbent actors that are locked-in current behavioral patterns due to sunk investments and regulatory frameworks. Research in this area can thus help to prevent irreversible technological and institutional lock-ins that create long-term path dependencies [40].

The aim of this paper is not to demonstrate that one pathway is economically more viable than the other and should thus be pursued. It should rather be interpreted as an insight that under a 100 percent RE setup, cost-optimal investments in transmission grid infrastructure is not as significant as in setups that include fossil and fissile technologies [21,22,24,25]. We also neglect other costs associated with a more distributed generation, for instance the costs of the Transmission System Operator (TSO) to maintain grid stability or the network codes. This should be considered when interpreting the results.

Our findings on grid expansion contrasting other studies are furthermore highly sensitive to the assumed potential for RE of each region. Consequently, an exhaustible potential deviating from the technical potential we assumed based on existing studies, might lead to different results. Future research should also include a broader set of renewable technologies that are of great relevance in 100 percent RE energy systems, such

as Concentrated Solar Power (CSP), and needs to assess sensitivities regarding the cost developments, e.g., to avoid the “penny-switching-effect” of linear cost-optimizing models. Other assumptions that are taken in this analysis need to be critically reflected, such as the feasibility and costs of long-distance transport of hydrogen or resource limitations regarding critical materials for the employed technologies.

Regarding the geographical extent of the model, our analysis aims at capturing several spatial and temporal interdependencies of RE generation on a large scale, but neglects a variety of characteristics on a micro-scale of electricity generation and distribution. It is therefore important to keep in mind that although one scenario setup is called decentralized, the geographic extent of the nodes is still relatively large. The model thus captures basic relations of long-distance electricity transmission, but does not provide any evidence or argument against other trends like distributed generation with small prosumers or self-sufficient renewable supply on a local level. RE also resemble a new paradigm of democratizing and decentralizing the energy supply based on local resources and regional autonomy [41]. The endogenous, cost-optimal investment in transmission infrastructure should therefore not be interpreted as an argument for a traditional and centralized generation structure.

8. Conclusions

Climate change and the declining costs for RE technologies require to provide visions of a carbon-free and cost-efficient electricity supply for political decision-makers as an alternative to scenarios based on nuclear power or fossil fuels in combination with Carbon-Capture-Transport-and-Storage (CCTS). Large-scale capacity expansion models can contribute to further evaluate these visions by considering both the spatial and temporal availability of renewable resources and the potential benefits from energy exchange, thus ensuring economic competitiveness and reliability. This paper investigates an electricity system based on 100 percent RE, considering the whole North American continent.

A linear least-cost dispatch and investment model is applied using the AnyMOD framework with spatially disaggregated data on renewable resources in a high temporal resolution. The influence of transmission infrastructure on investments in renewable generation is evaluated in three scenarios. Scenario *FIX* provides a cost-optimal RE power supply without allowing any transmission infrastructure expansion. In scenario *EXP*, generation and transmission capacity expansion is planned simultaneously to enable the exploitation of the best renewable resources under consideration of infrastructure expansion cost. Not allowing for any energy exchange between regions, scenario *DEC* examines a more decentralized infrastructure setup without any transmission infrastructure, where each node needs to meet its energy demand self-sufficiently.

Model results show that generation based on solar resources dominates the North American power mix with roughly 4000 TWh, followed by wind generation with approximately 800 TWh. Approximately 3000 GWh of short-term battery capacity and, depending on the scenario, between 180 and 300 TWh of long-term storage capacity are required to ensure the reliability of the power system. Enabling electricity exchange using the existing transmission infrastructure favors the RE resources with the highest availability. However, the benefits from an increased transmission infrastructure do not exceed the costs and high endogenous grid investments are not preferred as a least-cost option.

More general, the model results underline the results of other studies that a fully renewable energy system is feasible throughout North America, in particular with regards to its rich and diverse potential of RE. These results are replicated by a growing body of studies on other continents and countries. Since there is no unique technological solution, research needs to be conducted that considers the individual regional characteristics in terms of spatial and temporal renewable resource availability as well as energy demand. However, although the global transformation of energy systems towards RE is accelerating driven by climate change, there is still a remaining and massive action gap. Hence, not

only research on 100 percent RE but also a policy shift towards an increased deployment of RE technologies is important.

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Appendix A

Table A1. Nodal distribution. Note that Electric region refers to the the electric power region as described in Section 4.1 and Code refers to the nodal ID used in AnyMOD. The respective states are listed in the last column.

Country	Electric Region	Code	States
U.S.	Northwest	NorthWest	WA, OR, ID, MT, WY, CO, UT, NV
U.S.	California	California	CA
U.S.	Southwest	SouthWest	AZ, NM
U.S.	Texas	Texas	TX
U.S.	Central	US_Central	ND, SD, NE, KS, OK
U.S.	Midwest	MidWest	MN, IA, WI, MI, IL, IN, MO, AR, LA
U.S.	Mid-Atlantic	MidAtlantic	OH, PA, NJ, MD, DE, WV, VA, KY, DC
U.S.	Tennessee	Tennessee	TN, MS
U.S.	Florida	Florida	FL
U.S.	Southeast	SouthEast	AL, GA
U.S.	Carolina	Carolinas	NC, SC
U.S.	New York	NewYork	NY
U.S.	New England	NewEngland	VT, NH, MA, CT, RI, ME
Mexico	Baja California	BajaCalifornia	BC
Mexico	Baja California Sur	BajaCaliforniaSur	BCS, MUL
Mexico	Central	MEX_Central	HGO, MEX, CDMX
Mexico	Norte	Norte	DGO, CHIH
Mexico	Noroeste	NorOeste	SON, SIN
Mexico	Noreste	NorEste	TAMS, COAH, NL
Mexico	Occidental	Occidental	SLP, GTO, JAL, MICH, QRO, ZAC, AGS, COL, NAY
Mexico	Oriental	Oriental	TLAX, VER, MOR, PUE, OAX, CHIS, TAB, GRO
Mexico	Peninsular	Peninsular	YUC, CAMP, QR
Canada	Western Canada	West	BC, AB
Canada	Central Canada	CA_Central	SK, MB, ON
Canada	Eastern Canada	East	QC, NL, NB, PE, NS

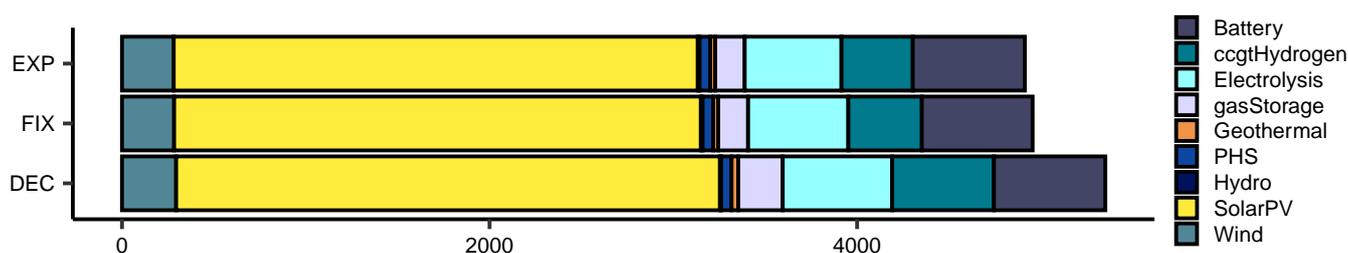


Figure A1. Overall installed energy conversion and storage capacities by scenarios in GW. Own illustration based on model results.

Table A2. 2050 Technology costs assumptions.

Technology	Specification	Investment Costs [\$/kW]	Operating Costs [\$/kW]	Source
Solar	Openspace PV	390	6.3	[42]
Wind	Onshore	1819	44.4	[42]
Wind	Offshore	3613	58.7	[42]
Electrolysis		514	14.6	[43]
Methanation		884	18	[43]
ccgtHydrogen		227	3.3	[44]
Hydro	New-Stream-Reach	7011	69	[45]
Hydro	Non-Powered Dams	5403	67	[45]
Geothermal	Hydrothermal	5995	123	[45]
Geothermal	Deep Geothermal; Flash	12,262	181	[45]
Geothermal	Deep Geothermal; Binary	31,331	500	[45]
biomassPlant		1005	6.6	[44]
gasPlant		424	8.6	[44]

Table A3. 2050 Storage costs assumptions.

Technology	Investment Costs [\$/kWh]	Investment Costs [\$/kW]	Operating COST	Lifetime [Years]	Source
Battery	201.8	91.9	1.4 [\$/kW]	18	[43]
pumpedStorage	86.1	0	13.5 [\$/kWh]	50	[10]
gasStorage	0.1	0	0	50	[10]

Table A4. 2050 Efficiency assumptions for carrier conversion and storage technologies. Note that RE technologies that convert electricity from freely available resources are not listed here.

Technology	Carrier In	Carrier Out	Efficiency [%]	Source
biomassPlant	biomass	electricity	0.4	[10]
electrolysis	electricity	hydrogen	0.785	[43]
methanation	hydrogen	synthGas	0.86	[43]
gasPlant	synthGas	electricity	0.66	[44]
ccgtHydrogen	hydrogen	electricity	0.63	[44]
pumpedStorage	electricity	electricity	0.85	[10]
battery	electricity	electricity	0.98	[43]
gasStorage	gas	gas	0.99	[10]

Table A5. Residual electricity network and line-specific parameters. Residual capacities are determined as described in Section 4.1. Line length is calculated between the node centroids using GIS. Expansion costs are assumed according to Carlsson et al. [33] and transportation losses according to Neumann et al. [34].

From	To	Residual Capacity [GW]	Expansion Costs [Mil. \$/GW]	Lifetime [years]	Losses [%]	Source	Length [km]
US_Central	MidWest	20.50	1908	60	0.04	[31]	705
California	NorthWest	11.75	2381	60	0.04	[31]	880
MidWest	MidAtlantic	10.20	2506	60	0.05	[31]	926
Tennessee	MidAtlantic	8.48	2341	60	0.04	[31]	865
MidWest	Tennessee	8.43	2268	60	0.04	[31]	838
MEX_Central	Oriental	7.35	1119	60	0.02	[30]	398
SouthEast	Tennessee	7.00	888	60	0.02	[31]	328
Florida	SouthEast	5.95	1380	60	0.03	[31]	510
SouthWest	Texas	5.90	2527	60	0.05	[31]	934
MidWest	Texas	5.74	3596	60	0.07	[31]	1329
NorthWest	SouthWest	5.58	2879	60	0.05	[31]	1064
NorthWest	West	5.52	3878	60	0.07	[32]	1433
Carolinas	MidAtlantic	5.25	1277	60	0.02	[31]	472
MidWest	CA_Central	4.76	3723	60	0.07	[32]	1376
NorEste	Occidental	4.51	1542	60	0.03	[30]	548
Texas	US_Central	4.43	3174	60	0.06	[31]	1173
NewYork	East	4.19	3415	60	0.06	[32]	1262
NewEngland	East	3.77	2793	60	0.05	[32]	1032
NorthWest	US_Central	3.61	3017	60	0.06	[31]	1115
Tennessee	Carolinas	3.60	2019	60	0.04	[31]	746
SouthEast	Carolinas	3.24	1434	60	0.03	[31]	530
NewYork	CA_Central	3.20	5106	60	0.09	[32]	1887
California	SouthWest	2.95	2806	60	0.05	[31]	1037
MEX_Central	Occidental	2.95	1017	60	0.02	[30]	362
California	BajaCalifornia	2.38	2341	60	0.04	[32]	865
NewYork	NewEngland	2.03	1139	60	0.02	[31]	421
MidAtlantic	NewYork	2.00	1607	60	0.03	[31]	594
NorEste	Oriental	1.60	2922	60	0.05	[30]	1039
NorOeste	Occidental	1.38	3154	60	0.06	[30]	1122
Oriental	Peninsular	1.20	2151	60	0.04	[30]	765
Texas	NorEste	1.19	1659	60	0.03	[32]	613
US_Central	CA_Central	1.19	3477	60	0.06	[32]	1285
Norte	NorEste	1.00	1529	60	0.03	[30]	544
NorOeste	Norte	1.00	1187	60	0.02	[30]	422
Norte	Occidental	0.30	2181	60	0.04	[30]	776
BajaCalifornia	BajaCaliforniaSur	0.00	1669	60	0.03	[30]	594
NorOeste	BajaCalifornia	0.00	1488	60	0.03	[30]	529
Norte	Texas	0.00	2097	60	0.04	[32]	775
Norte	SouthWest	0.00	2165	60	0.04	[32]	800
NorOeste	SouthWest	0.00	1740	60	0.03	[32]	643
CA_Central	East	0.00	4900	60	0.09	Assumption	1743
West	CA_Central	0.00	4572	60	0.08	Assumption	1626

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