Clean Energy Future Technical Review

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1. INTRODUCTION

Synapse conducted an analysis of the impacts of a clean energy future on electric-sector emissions and costs. In this technical review, we document the data, assumptions, and results related to modeling the emissions reductions of the scenario as compared to a reference scenario. We refer to the scenarios throughout this document as the "Clean Energy Future scenario" and "Reference scenario."

The Reference scenario is a no-new-policy scenario in which existing state renewable portfolio standards are met but not expanded. New load is met largely by new gas-fired generating capacity, and the existing fleet of coal-fired and nuclear plants are retrofit to continue operating.

The Clean Energy Future scenario represents a substantial shift towards renewables as the costs of these technologies continue to decline and incentives are put in place to encourage adoption. Aggressive energy efficiency policies reduce demand by 1,344 terawatt-hours (TWh) as compared to the Reference scenario in 2040, and the expansion of electric vehicles reduces emissions in the transport sector as well.

Our analysis relies on the Renewable Energy Development System (ReEDS) model, a tool designed by the National Renewable Energy Laboratory (NREL) for long-term analysis of the development of the electric power sector. We updated several of the default assumptions in the ReEDS model based on recent research. This report documents those assumptions and provides a high-level overview of the results.

2. THE REEDS MODEL

ReEDS is a long-term capacity expansion and dispatch model of the electric power system in the lower 48 states. It has a high level of renewable resource detail, with many wind and solar resource regions, each with availability by resource class and unique grid connection costs. Model outputs include generation, capacity, transmission expansion, capital and operating costs, and emissions of CO_2, SO_2, NO_X, and mercury.[1] The model operates through 2050 in two-year steps, with each two-year period divided into 17 time slices representing morning, afternoon, evening, and night in each of the four seasons, plus an additional summer peak time slice. ReEDS includes data on the existing fossil fuel facilities in each of the model's 134 Power Control Areas (PCAs).

ReEDS benefits from NREL's detailed data sets on renewable resource potentials and constraints across the country, providing a higher level of resolution than other similar industry models. Wind resources

[1] See: Short et al. 2010. Regional Energy Deployment System (ReEDS). Available at: http://www.nrel.gov/docs/fy12osti/46534.pdf.

are modeled in 356 regions of the United States, based on high-resolution wind speed modeling and taking into account environmental and land-use exclusions. Biomass, geothermal, solar PV, and hydropower plants are built at the resolution of the model's 134 PCAs.

In addition to meeting loads in each time slice, there are a number of reserve margin constraints the model must also achieve. Planning reserves—the level of firm generating capacity above the forecasted system peak—are modeled based on levels required by the North American Electric Reliability Corporation (NERC) in 13 regions, and range from 12.5 to 17.2 percent. ReEDS also models a number of operating reserve requirements, including contingency reserves (6 percent of demand in each time slice), and frequency regulation reserves (1.5 percent of demand).

2.1. Caveats and Data Limitations

When evaluating scenarios over very long timeframes in ReEDS, it is important to remember that key inputs are being forecasted (e.g., loads, fuel prices, and resource costs) over a 35-year period from 2015 to 2050. Over at least the latter half of this period, these forecasts and the modeling results should be treated as highly uncertain.

In Synapse's modeling work, several key aspects of these scenarios were developed "exogenously" and entered into the model as inputs. These assumptions include:

- Energy efficiency trajectory
- Rooftop PV market penetration
- Electric vehicles penetration (although the model can choose how and when to utilize electric vehicles as storage)
- Environmental costs at coal plants, which are based on Synapse's Coal Asset Valuation Tool (CAVT)[2]

Synapse developed the assumptions that change the levels of these resources across different scenarios. ReEDS does not optimize for costs associated with the items identified above, beyond a simplified representation of the Clean Air Interstate Rule governing SO_2 emissions impacting coal plant environmental costs. Instead, these costs are calculated in the Synapse-developed ReEDS Postliminary Reporting Tool (RePRT).

For this analysis, we take ReEDS system costs by technology, control area, and year as raw outputs from the model and feed them through RePRT before use and comparison across scenarios. RePRT is a Synapse-built post-processing tool that translates ReEDS outputs into annualized total cost to the

[2] Knight, P, J. Daniel. 2015. *Forecasting Coal Unit Competitiveness: Coal Retirement Assessment Using Synapse's Coal Asset Valuation Tool (CAVT).* Available at: http://synapse-energy.com/sites/default/files/Forecasting-Coal-Unit-Competitiveness-14-021.pdf.

system by technology and control area. For fixed operations and maintenance (O&M) charges and fuel costs, the tool simply pulls outputs straight from ReEDS. For capital costs for new technologies, however, the tool calculates and adds interest during construction to the capital cost outputs from ReEDS, and then amortizes those costs over a technology-specific investment life. The tool processes capacity, generation, and emissions outputs from ReEDS into a form that allows Synapse to easily parse, aggregate, and present results at various resolutions.

2.2. Integration of Wind and Solar Costs

The amount of electricity generated from moment to moment by wind and solar resources is uncertain. In order to reliably manage variable resources, several measures may be necessary on top of the conventional operating and planning reserves that system operators have historically used to maintain the reliability of the electric power system. ReEDS endogenously calculates several integration related parameters, including:

- Capacity value: As wind and solar penetration increases, their contribution to peak capacity must decline based on region-specific parameters. As capacity value declines, ReEDS will have to build more, or other, resources to meet regional planning reserve requirements.
- Forecast error reserves: In addition to contingency and regulation reserves, ReEDS calculates incremental reserve requirements to ensure the grid can sufficiently ramp resources up or down with unexpected fluctuations in wind and solar output. ReEDS must maintain sufficient reserves at all times, and will build new conventional (or storage) capacity to serve these reserves.
- Curtailment: In some situations, more renewable energy is produced than can be consumed—either as a result of low demand or inflexible “must run” conventional generators. This represents a real cost to the system, which could otherwise use this curtailed energy.

The costs of these integration measures are typically a small fraction of the energy saved. A recent Argonne National Lab study found integration costs of $1.7 per megawatt-hour (MWh) to $3.8 per MWh for a 17 percent solar scenario, in order to account for the reserves and forecast error requirements that ReEDS calculates internally.[3] ReEDS does not account for the increased costs of wear and tear on conventional generators as a result of having to turn off and on more frequently. These costs are estimated to be below $1 per MWh of wind or solar generation,[4] as compared to fuel and operating costs of about $30 per MWh for conventional fossil fuel-fired generators.

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[3] Mills, A., A. Botterud, J. Wu, Z. Zhou, B-M. Hodge, M. Heaney. 2013. *Integration of Solar PV in Utility System Operations*. Argonne National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6525e.pdf.

[4] Lew, D., G. Brinkman. 2013. Western Wind and Solar Integration Study – Phase 2. National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy13osti/58798.pdf.

3. INPUT ASSUMPTIONS

ReEDS optimizes new build and retirement decisions based on the lowest cost solution to meet demand within reliability constraints. These biannual optimization decisions are informed largely by the assumptions and inputs used in each model run. Table 1 below summarizes the key distinctions among the inputs between the two scenarios, which are described in further detail below. We highlight several of the assumptions used in this analysis; for a more detailed description of ReEDS default assumptions, see the ReEDS documentation or recent NREL studies such as the 2012 Renewable Electricity Futures study.[5]

Table 1. Key input assumptions in Reference and Clean Energy Future scenarios

Assumption	Reference	Clean Energy Future
Demand-Side Resources		
Energy Efficiency	AEO 2014 Reference Case	Ramping from near-term state-specific targets to 2% annual savings beginning in 2020
Demand Response	10% potential by 2040	15% potential by 2040
Distributed PV	EF Reference: 80% below Sunshot 50 costs and capacity additions	Adjusted Sunshot 75 scenario: 75% cost reduction with capacity additions redistributed across the scenario
Electric Vehicles	None	25% of light vehicles by 2040 (45% of this load available for grid management)
Supply-Side Resources		
Coal Retirements	All announced by June 2015	All retired by 2040 or at 35 years old if built after 2005
Nuclear Lifetime	60 years	60 years
Renewable Target	Existing state RPS	70% National RPS

Preliminary model runs resulted in residential consumer electric bill savings for every state in the lower 48 except for one: North Dakota. Upon further investigation of the causes of this anomaly, we found that coal plants were remaining in operation later in North Dakota than in nearby states, delaying North Dakota's adoption of renewables in the Clean Energy Future. By the time North Dakota's coal plants retire, other state's efficiency savings make abundant clean energy resources available for export; as a result, North Dakota purchases imported energy rather than building its own low-cost renewables. To

[5] National Renewable Energy Laboratory. 2012. *Renewable Electricity Futures Study.* Hand, M.M., S. Baldwin, E. DeMeo, J.M. Reilly, T. Mai, D. Arent, G. Porro, M. Meshek, D. Sandor eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures.

mitigate this anomaly, we adjusted our inputs to assume that North Dakota, like its neighbors, is an early adopter of wind technology, and in this way avoids the cost of importing energy towards the end of the compliance period.

3.1. Load Growth and Energy Efficiency

Electricity loads from the U.S. Energy Information Administration's (EIA) 2014 Annual Energy Outlook (AEO) form the basis of the loads in both scenarios.[6] AEO's Reference Case—used in our Reference scenario—embeds a small amount of energy efficiency based on existing federal policies, but does not include existing state Energy Efficiency Portfolio Standards (EEPS). In the Clean Energy Future, we ramp up savings to the near-term high annual incremental savings rate estimates presented in a recent Lawrence Berkley National Laboratory study.[7] These savings rates are achieved by 2020 and do not represent long-term energy efficiency potential. Based on recently achieved savings rates in leading states and recent studies of long-term efficiency potential, a 2 percent annual savings rate is then reached in each state by 2029, ramping by 0.2 percentage points until the target is met and maintained. Even after accounting for the growth in demand associated with the integration of electric vehicles described below, national demand declines slightly from 2012 as a result of this level of energy efficiency.

Only program administrator costs are included as the costs of energy efficiency in this analysis. We use first-year total costs of 55 cents per kilowatt-hour, consistent with the assumptions used in the U.S. Environmental Protection Agency's (EPA) June 2014 proposed Clean Power Plan.[8] These costs are escalated as annual savings increase to represent progressively more expensive measures. Costs are 120 percent of base costs for 0.5-1 percent incremental savings, and 140 percent of base costs for savings beyond 1 percent. We assume a 50/50 split between program and participant costs, however our cost reporting focuses on utility costs. As a result we exclude participant costs.

3.2. Demand Response

ReEDS requires inputs for both costs and potential quantity of demand response as a percentage of peak load in order to determine how much of the resource to select. Load is shifted from peak to off-peak periods, with no change in total energy consumption. We assume up to 9 percent of peak load can be met by demand response in 2030 in the Reference scenario, based on Navigant's *Assessment of*

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[6] The EIA has since released an AEO 2015 report. Electric demand in this forecast is 1 percent lower in 2020, and 3 percent lower in both 2030 and 2040 than the AEO 2014 assumptions used in this study.

[7] Barbose, G. et al. 2013. *The Future of Utility-Customer Funded Energy Efficiency Programs in the United States*. Lawrence Berkeley National Laboratory. LBNL-5803E. Available at: http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend.

[8] EPA. 2014. *GHG Abatement Measures: Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants*. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf. Page 5-53. Costs are in 2011$.

Demand-Side Resources in the Eastern Interconnection.[9] After 2030, we allow this share to grow to reflect new opportunities enabled by advanced meters. The Clean Energy Future scenario reaches Navigant's High case trajectory: 9 percent by 2020, 12 percent by 2030, and 15 percent by 2040.

Costs are modeled based on a supply curve, rising from $20 per kilowatt-month (kW-month) at 3 percent of peak load to $100 per kW-month at 18 percent of peak load, informed by the Navigant study.

3.3. Solar Power

We assume cost reduction trajectories for utility and rooftop solar PV based on the NREL's SunShot Vision study, which describes significant cost reductions from baseline levels by 2020. In the Reference scenario we assume costs decline 50 percent, while in the Clean Energy Future scenario we assume a cost reduction of 75 percent by 2040 based on ongoing review of data and forecasts for module costs, the balance of system costs,[10] and total installed costs, including data from other countries with fast-growing PV sectors. We assume that large ground mounted projects reach $1.00 per DC watt in 2040 (in 2013 dollars). While module costs have been well below $1.00 per watt in recent years, the many other costs to permit and construct a solar plant ("soft costs") have persistently kept realized costs higher.

ReEDS is a supply-side-only model: it does not optimize the decisions residential homeowners would make to install rooftop PV systems. These are input into the model based on a separate tool NREL developed for its SunShot analysis. Approximately 8 GW of rooftop PV is installed today. In the Reference scenario, we assume this growth rate slows as residential rate structures evolve to disincentivize distributed generation, leading to 11 GW by 2020, 32 GW by 2030, and 46 GW by 2040.

In the Clean Energy Future scenario, we assume that policy structures are put in place to facilitate residential PV and, as a result, PV growth accelerates. In this scenario we follow an adjusted version of the build-out trajectory associated with the SunShot Vision 75 percent cost reduction trajectory (developed using the SolarDS model). This trajectory is more front-loaded to reflect recent cost declines—reaching 18 GW by 2020, 94 GW by 2030, and 157 GW by 2040.

In each scenario, we only calculate the utility cost of distributed PV and not the full installed cost. We assume that utilities pay for excess energy from rooftop systems at the marginal cost for energy. Based on recent studies, we assume that 59 percent of the generation from distributed PV is excess and sold back onto the grid. Each region's observed electricity price in multiplied by its excess generation from distributed PV in order to determine utility distributed PV costs.[11]

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[9] Navigant. 2013. *Assessment of Demand-Side Resources within the Eastern Interconnection*. Available at: https://eispctools.anl.gov/document/19/file.

[10] "Balance of system" costs include both non-module physical costs (inverters, hardware) as well as financing and other soft costs, such as customer acquisition, installation labor, permitting, inspection, and interconnection.

[11] Based on Synapse analysis of Xcel Energy Study Report "Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System." Prepared in response to CPUC Decision No. C09-1223. Pages 58-61.

3.4. Wind

Wind supply curves are defined for 356 regions in ReEDS, each with a specified capacity potential in each wind Class 3 through 7. The potential for new wind is based on modeling by AWS Truepower using the Mesomap® process. Results were processed to exclude areas such as urban areas, federally protected lands, and onshore water features. Our costs for land-based wind are based on research done for the Department of Energy's recent *Wind Vision Report*.[12] Base wind costs in 2015 range from $1,759 per kW for projects in Class 3 areas to $1,641 per kW for projects in Class 7. This represents the turbine itself—ReEDS adds interconnection costs to the regional transmission system based on GIS analysis of wind resources.

The *Wind Vision Report* assumes cost reductions and capacity factor increases over time for land-based wind. In this analysis, we hold base costs for land-based wind constant over the study period at the levels cited above, but we use the increasing capacity factors from the *Wind Vision.* Possible land-based capacity factors range from 35 to 49 percent in 2020 and range from 38 to 58 percent in 2040.

Offshore wind costs are also taken from the *Wind Vision* assumptions, in which costs are forecast to fall over time. Base overnight costs for shallow offshore wind resources in 2020 are $4,471 per kW in Class 3 areas and $4,052 for projects in all other areas. These costs fall by roughly 30 percent over the study period. Fixed O&M for shallow offshore wind is $109 per kW-year in 2020, falling to $94 per kW-year in 2040. Possible offshore capacity factors range from 35 percent to 48 percent in 2020 and 40 percent 54 percent in 2040. The model also characterizes deep offshore resources, available when the supply of cheaper shallow resources has been exhausted. Full documentation of these assumptions is available in the *Wind Vision* study.

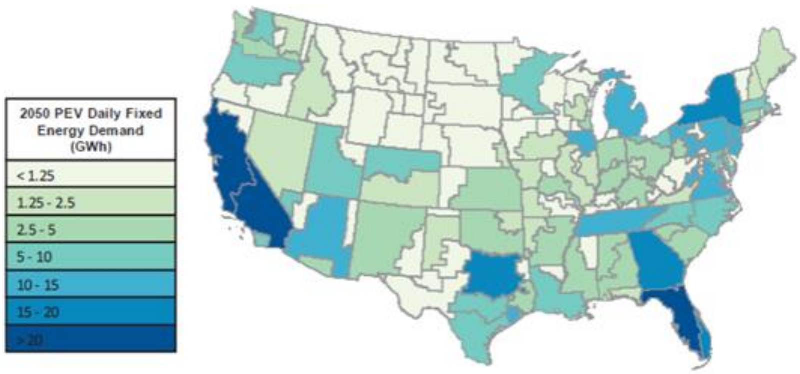
3.5. Electric Vehicle Loads

The electric vehicle loads we add in the Clean Energy Future scenario are taken from NREL's *Renewable Electricity Futures* study. NREL developed several electric vehicle scenarios for this work and evaluated the scenarios using ReEDS. We use the electric vehicle demand data from NREL's higher penetration scenario, in which 35 percent of light duty automobile sales are electric vehicles by 2040. This results in about 25 percent of the aggregate vehicle stock being electric vehicles in 2040.

The vehicle electricity use in this scenario represents a mix of electric vehicle types consuming an average 6 kWh of electricity per vehicle per day. Load shapes are based on 110-volt, 1.4-kW charging infrastructure. Figure 1 shows the distribution of electric vehicle electricity demand in 2050. Loads in 2040 are about 70 percent of this level.

[12] U.S. Department of Energy. 2015. *Wind Vision Report*. Accessed June 22, 2015. Available at: http://energy.gov/eere/wind/wind-vision.

Figure 1. Regional distribution of electric vehicle electricity use in the Clean Energy Future scenario



Reproduced from Figure K-10 of NREL Renewable Electricity Futures Study

We follow the *Renewable Energy Futures* study in assuming that, as technology and policy develop, an increasing part of the electric vehicle load becomes controllable by the local utility. By 2040, 55 percent of the electric vehicle fleet is controllable such that charging can be directed to off-peak periods. Note that our electric vehicle assumptions include only the electrification of light-duty vehicles (and not commercial or industrial vehicles or mass transit). Light-duty vehicles currently comprise about three-quarters of the vehicle-miles traveled by all on-road vehicles.

3.6. Gas and Coal Assumptions

Fixed cost assumptions for new gas and coal plants are based on a 2012 study by Black & Veatch and provided in Table 2 below.[13] Costs are presented in 2013 dollars. New builds and retirements are assumed to be consistent with those announced to date. In the Reference scenario, no additional retirements are assumed as inputs, though the ReEDS model will retire a plant that is underutilized. In the Clean Energy Future scenario, we assume all coal plants built before 2005 are retired by 2040. Plants built after 2005 are retired after a 35-year lifetime.

Table 2. Fixed cost assumptions for new gas and coal plants in 2020 (2013$)

	Overnight Cost ($/kW)	Heat Rate (MMBtu/MWh)
Pulverized Coal	$3,140	9.47
Coal with CCS	$7,128	12.6
Coal IGCC	$4,357	9.03
Gas CT	$837	10.30
Gas CC	$985	6.74
Gas CC with CCS	$3,100	8.80

[13] Black & Veatch. 2012. *Cost and Performance Data for Power Generation Technologies*. Prepared for NREL. Available at: http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E.

3.7. Nuclear power

The ReEDS model has costs for new nuclear plants consistent with AEO 2014, and assumes the completion of nuclear plants currently under construction. No new nuclear is built by the model in either the Reference or Clean Energy Future scenario: lower cost resources are widely available, particularly in the absence of a policy specifically incentivizing zero-emission generating sources such as nuclear. Nuclear power plants are assumed to retire after 60 years after one re-licensing renewal in both scenarios.

4. RESULTS AND DISCUSSION

The figures below report modeling results for generation (Figure 2), capacity (Figure 3), and carbon dioxide (CO_2) emissions (Figure 4). In the Clean Energy Future scenario, electric-sector CO_2 emissions for the lower 48 states decline 19 percent from 2010 levels by 2020, 57 percent by 2030, and 84 percent by 2040.

Note that generation and emissions values produced by ReEDS may differ from actual generation and emissions values for years that have already occurred (i.e., 2010, 2012, and 2014). Particularly in 2012 with the rapid drop in gas prices, ReEDS tends to ramp coal generation down below observed levels. This may be a result of ReEDS not reflecting all the operational and non-market factors affecting the operating decisions of system operators. Depending on the context, it may make sense in certain situations to compare values projected by ReEDS for out years (2016-2040) to actual generation data and actual emissions data. Historical generation data is typically retrieved from the annual Form 923 assembled by EIA.[14] Historical emissions data is available via EPA's Air Market Programs dataset.[15]

Our analysis examines avoided CO_2 emissions and cost savings per household in seven regions across the United States. States in the Lower 48 were grouped based on the degree to which they are currently interconnected. Figure 5 displays the allocation of states to regions.

[14] Available at: http://www.eia.gov/electricity/data/eia923.

[15] Available at: http://ampd.epa.gov/ampd.

Figure 2. Generation (TWh) by technology in the (a) Reference and (b) Clean Energy Future scenarios

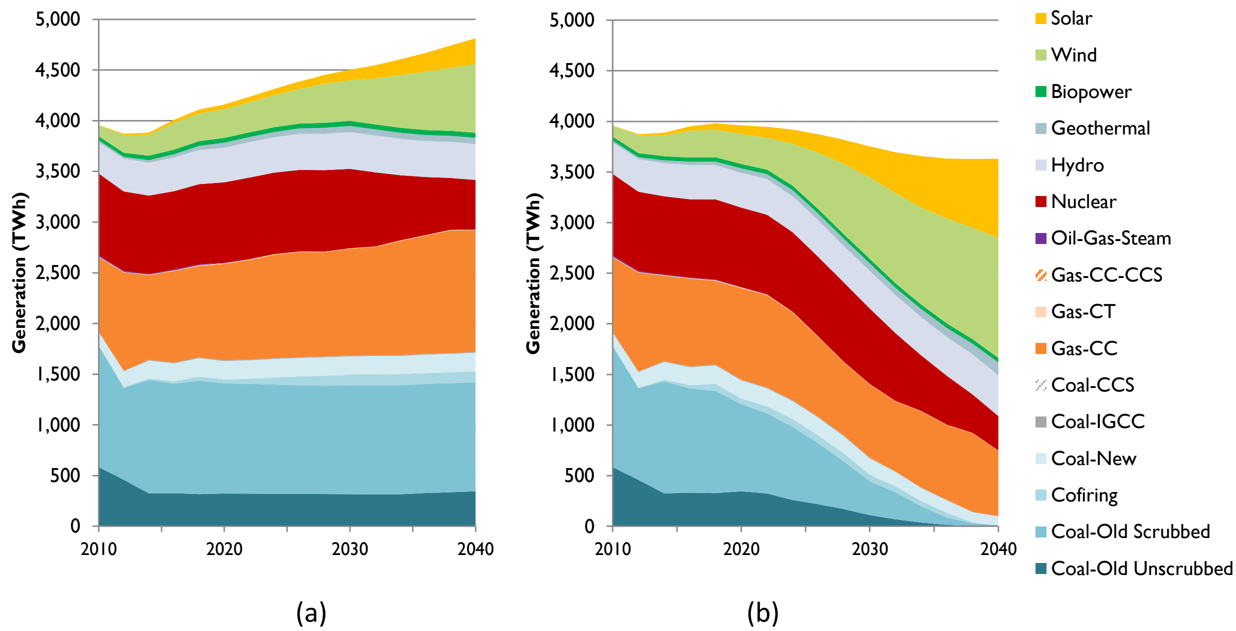


Figure 3. Capacity (MW) by technology in the (a) Reference and (b) Clean Energy Future scenarios

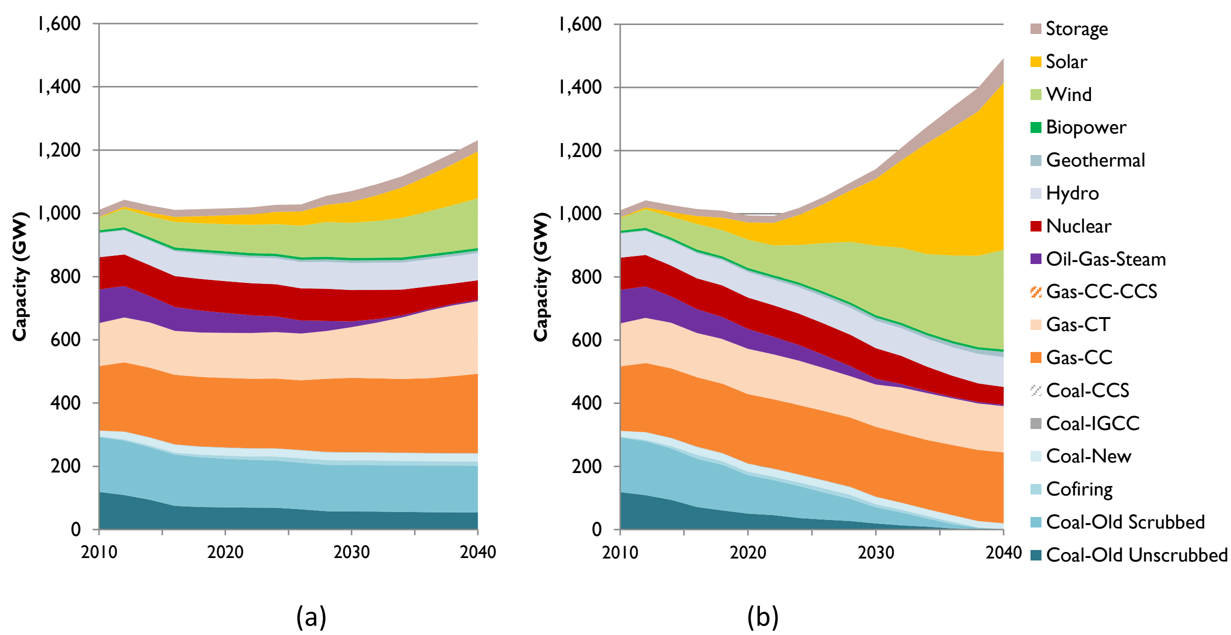


Figure 4. National CO_2 emissions in the Reference and Clean Energy Future scenarios (metric tons)

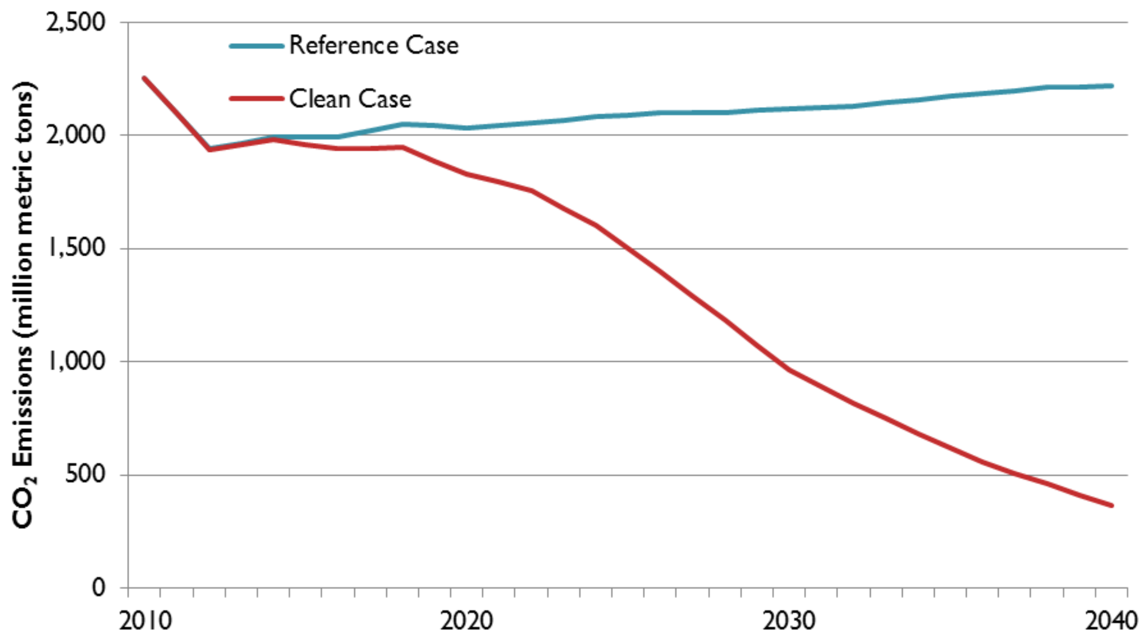


Figure 5. Allocation of states to regions