Zero Air Pollution and Zero Carbon From All Energy Without Blackouts at Low Cost in Minnesota

By Mark Z. Jacobson, Stanford University, December 7, 2021

This infographic summarizes results from simulations that demonstrate the ability of Minnesota to match all-purpose energy demand with wind-water-solar (WWS) supply, storage, and demand response continuously every 30 seconds for the years 2050-2051. All-purpose energy is energy for electricity, transportation, buildings, and industry. Results are shown for the Minnesota grid interconnected within the Midwest Reliability Organization (MRO) grid (IA, KS, MN, NE, ND, OK, SD, WI). The ideal transition timeline is 100% WWS by 2035; however, results are shown for 2050-2051, after additional population growth has occurred.

WWS electricity-generating technologies include onshore and offshore wind, solar photovoltaics (PV) on rooftops and in power plants, concentrated solar power (CSP), geothermal, hydro, tidal, and wave power. WWS direct heat-sources include geothermal and solar. WWS storage includes electricity, heat, cold, and hydrogen storage. WWS equipment includes electric and hydrogen fuel cell vehicles, heat pumps, induction cooktops, arc furnaces, induction furnaces, resistance furnaces, lawnmowers, etc. No fossil fuels, nuclear bioenergy, or carbon capture is included.

The results are derived from the LOADMATCH grid model using 2050 U.S. state-specific business-as-usual (BAU) and wind-water-solar (WWS) all-sector load data projected from 2018 EIA state load data. The model also uses 30-second resolution WWS supply plus building heating/cooling load data from the GATOR-GCMOM weather-prediction model. The models and results are described in the following publication:

Jacobson, M.Z., A.-K. von Krauland, S.J. Coughlin, F.C. Palmer, and M.M. Smith (2021), Zero air pollution and zero carbon from all energy at low cost and without blackouts in variable weather throughout the U.S. with 100% wind-water-solar (WWS) and storage, Renewable Energy, 184, 430-444, 2022, doi:10.1016/j.renene.2021.11.067, https://web.stanford.edu/group/efmh/jacobson/Articles/I/WWS-USA.html

Main results. Transitioning Minnesota to 100% WWS for all energy purposes…

- **Keeps the grid stable 100% of the time. This is helped by the fact that, during cold storms, winds are stronger (Figure 1) and wind/solar are complementary in nature;**
- **Creates 103,000 more long-term, full-time jobs than lost;**
- **Saves 608 lives from air pollution per year in 2050 in Minnesota;**
- **Eliminates 110 million tonnes-CO_2e per year in 2050 in Minnesota;**
- **Reduces 2050 all-purpose, end-use energy requirements by 57.2%;**
- **Reduces Minnesota's 2050 annual energy costs by 63.9% (from $46.4 to $16.8 b/y);**
- **Reduces annual energy, health, plus climate costs by 85.5% (from $116 to $16.8 b/y);**
- **Costs ~$168 b upfront. Upfront costs are paid back through energy sales. Costs are for WWS electricity, heat, and H_2 generation; electricity, heat, cold, and H_2 storage; heat pumps for district heating; all-distance transmission; and distribution;**
- **Requires 0.14% of Minnesota land for footprint, 0.71% for spacing.**

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Table 1. Reduced End-Use Demand (Load) Upon a Transition From BAU to WWS

1st row: 2018 annually-averaged end-use load (GW) and percentage of the load by sector in Minnesota. 2nd row: estimated 2050 total annually-averaged end-use load (GW) and percentage of the total load by sector if conventional fossil-fuel, nuclear, and biofuel use continues to 2050 under a BAU trajectory. 3rd row: estimated 2050 total end-use load (GW) and percent of total load by sector if 100% of BAU end-use all-purpose delivered load in 2050 is instead provided by WWS. Column (i) shows the percent reductions in total 2050 BAU load due to switching from BAU to WWS, including the effects of (f) energy use reduction due to the higher work to energy ratio of electricity over combustion, (g) eliminating energy use for the upstream mining, transporting, and/or refining of coal, oil, gas, biofuels, bioenergy, and uranium, and (h) policy-driven increases in end-use efficiency beyond those in the BAU case. Column (j) is the ratio of electricity load (=all energy load) in the 2050 WWS case to the electricity load in the 2050 BAU case. Whereas Column (j) shows that electricity consumption increases in the WWS versus BAU cases, Column (i) shows that all energy decreases.

Scenario	(a) Total annual average end-use load (GW)	(b) Resid-ential percent of total end-use load	(c) Com-mercial per-cent of total end-use load	(d) Indus-try per-cent of total end-use load	(e) Trans-port per-cent of total end-use load	(f) Percent change end-use load w/WWS due to higher work: energy ratio	(g) Percent change end-use load w/WWS due to elim-inating upstream	(h) Percent change end-use load w/WWS due to effic-iency beyond BAU	(i) Overall percent change in end-use load with WWS	(j) WWS: BAU elec-tricity load
Minnesota										
BAU 2018	46.2	20.2	16.0	30.2	33.6					
BAU 2050	51.4	17.2	16.6	38.1	28.1					
WWS 2050	22.0	15.4	16.7	51.2	16.7	-40.28	-10.57	-6.34	-57.19	2.17

Table 2. 2050 WWS End-Use Demand by Sector

2050 annual average end-use electric plus heat load (GW) by sector in the MRO region after energy in all sectors has been converted to WWS. Instantaneous loads can be higher or lower than annual average loads. Values for each region equal the sum over all state values from Table 1.

State/region	Total	Residential	Commercial	Industrial	Transport
MRO	131.7	16.45	17.38	79.16	18.72

Table 3. WWS End-Use Demand by Load Type

Annual average WWS all-sector inflexible and flexible loads (GW) for 2050 in the MRO region. "Total load" is the sum of "inflexible load" and "flexible load." "Flexible load" is the sum of "cold load subject to storage," "low-temperature heat load subject to storage," "load for H_2" production, compression, and storage (accounting for leaks as well), and "all other loads subject to demand response (DR)." Annual average loads are distributed in time at 30-s resolution, as described in the text. Instantaneous loads, either flexible or inflexible, can be much higher or lower than annual average loads. Also shown is the annual hydrogen mass needed in each region, estimated as the H_2 load multiplied by 8,760 hr/yr and divided by 59.01 kWh/kg-H_2.

State/region	Total end-use load (GW)	Inflex-ible load (GW)	Flex-ible load (GW)	Cold load subject to storage (GW)	Low-temp-erature heat load subject to storage (GW)	Load sub-ject to DR	Load for H_2 (GW)	H_2 needed (Tg-H_2/yr)
MRO	131.7	66.7	65.0	0.40	4.06	8.10	52.5	1.20

Table 4. Nameplate Capacities Needed by 2050 and Installed as of 2019/2020

Final (from LOADMATCH) 2050 total (existing plus new) nameplate capacity (GW) of WWS generators needed to match power demand with supply, storage, and demand response continuously during 2050-2051 in Minnesota (when interconnected within MRO) and in the MRO region as a whole. Also provided are nameplate capacities already installed as of 2019 or 2020 end. Nameplate capacity equals the maximum possible instantaneous discharge rate.

Year	Onshore wind	Off-shore wind	Resi-dential roof-top PV	Comm /govt rooftop PV	Utility PV	CSP with stor-age	Geoth ermal -elec-tricity	Hydro power	Wave	Tidal	Solar therm al	Geoth ermal heat
2019/20 Minnesota	4.05	0	0.05	0.04	0.90	0	0	1.71	0	0	0	0
2019/20 MRO	38.13	0	0.14	0.16	1.02	0	0	5.84	0	0	0	0
2050 Minnesota	33.16	9.36	18.08	25.17	24.39	0	0	1.71	0.23	0	0	0
2050 MRO	210.49	17.97	73.27	101.4	295.8	0	0	5.84	0.46	0	0	0

11 states imported hydropower in 2019 from Canada. A nameplate capacity of 8,988 MW built in Canada was assigned, based on additional data, to those 11 states as follows: 1,269.3 MW to California; 739 MW to Maine; 3.4 MW to Maryland; 2.2 MW to Massachusetts; 503 MW to Michigan; 1,498.7 MW to Minnesota; 2,299.1 MW to New York; 68.5 MW to North Dakota; 3.4 MW to Ohio; 2,598.1 MW to Vermont; and 3.4 MW to Virginia. Any such nameplate capacities are included in the hydropower nameplate capacities in this table.

Table 5. Capacity Factors of WWS Generators

Simulation-averaged 2050-2051 capacity factors (percent of nameplate capacity produced as electricity before transmission, distribution or maintenance losses) in the MRO region. The mean capacity factors in this table equal the simulation-averaged power supplied by each generator in each region (Table 6) divided by the nameplate capacity of each generator in each region (Table 4).

Scenario	On-shore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydr opow er	Wave	Tidal	Solar therm al	Geo-thermal heat
MRO	0.466	0.418	0.205	0.224	0	0	0.591	0.297	0	0	0

Capacity factors of offshore and onshore wind turbines account for array losses (extraction of kinetic energy by turbines). The symbol "--" indicates no installation of the technology. Rooftop PV panels are fixed-tilt at the optimal tilt angle of the country they reside in; utility PV panels are half fixed optimal tilt and half single-axis horizontal tracking.

Table 6. Percent of Load Met by Different WWS Generators

Projected simulation-averaged 2050-2051 all-sector WWS energy supply before transmission and distribution losses, storage losses, or shedding losses, in the MRO region, and percent of supply met by each generator, based on LOADMATCH simulations. Simulation-average power supply (GW) equals the simulation total energy supply (GWh/yr) divided by the number of hours of simulation. The percentages for each region add to 100%. Multiply each percentage by the 2050 total supply to obtain the GW supply by each generator. Divide the GW supply from each generator by its capacity factor (Table 5) to obtain the 2050 nameplate capacity of each generator needed to meet the supply (Table 4).

Scenario	Total WWS supply (GW)	On-shore wind (%)	Off-shore wind (%)	Roof PV (%)	Utility PV (%)	CSP with stor-age (%)	Geoth ermal elec-tricity (%)	Hydr opow er (%)	Wave (%)	Tidal (%)	Solar ther-mal heat (%)	Geo-ther-mal heat (%)
MRO	211.2	46.45	3.56	16.95	31.34	0	0	1.63	0.07	0	0	0

Table 7. Characteristics of Storage Resulting in Matching Demand With 100% WWS Supply
Maximum charge rates, discharge rate, storage capacity, and hours of storage at the maximum discharge rate of all electricity, cold and heat storage needed for supply + storage to match demand in MRO, which includes Minnesota.

Storage type	Max charge rate (GW)	Max discharge rate (GW)	Max storage capacity (TWh)	Max storage time at max discharge rate (hr)
PHS	7.06	7.06	0.10	14
CSP-elec.	0	0	--	--
CSP-PCM	0	--	0	--
Batteries	570	570	2.28	4
Hydropower	3.36	5.84	29.41	5,036
CW-STES	0.16	0.16	0.0022	14
ICE	0.24	0.24	0.0033	14
HW-STES	12.24	12.24	0.10	8
UTES-heat	0	12.24	0.29	24
UTES-elec.	12.24	--	--	--

PHS=pumped hydropower storage; PCM=Phase-change materials; CSP=concentrated solar power; CW-STES=Chilled-water sensible heat thermal energy storage; HW-STES=Hot water sensible heat thermal energy storage; and UTES=Underground thermal energy storage (either boreholes, water pits, or aquifers). The peak energy storage capacity equals the maximum discharge rate multiplied by the maximum number of hours of storage at the maximum discharge rate.

Pumped hydro storage is estimate as the existing (in 2020) nameplate capacity plus the nameplate capacity of pending licenses and of preliminary permits by state (in 2020) (FERC, 2021). If a region has no existing or pending pumped hydro, a minimum of 100 MW is imposed to account for the addition of pumped hydro between 2021 and 2050.

Heat captured in a working fluid by a CSP solar collector can either be used immediately to produce electricity by evaporating water and running it through a steam turbine connected to a generator, stored in a phase-change material, or both. The maximum direct CSP electricity production rate (CSP-elec) equals the maximum electricity discharge rate, which equals the nameplate capacity of the generator. The maximum charge rate of CSP phase-change material storage (CSP-PCM) is set to 1.612 multiplied by the maximum electricity discharge rate, which allows more energy to be collected than discharged directly as electricity. Thus, since the high-temperature working fluid in the CSP plant can be used to produce electricity and charge storage at the same time, the maximum overall electricity production plus storage charge rate of energy is 2.612 multiplied by the maximum discharge rate. This ratio is also the ratio of the mirror size with storage versus without storage. This ratio can be up to 3.2 in existing CSP plants. The maximum energy storage capacity equals the maximum electricity discharge rate multiplied by the maximum number of hours of storage at full discharge, set to 22.6 hours, or 1.612 multiplied by the 14 hours required for CSP storage to charge when charging at its maximum rate.

Hydropower's maximum discharge rate in 2050 is its 2019 nameplate capacity. Hydropower can be recharged only naturally by rainfall and runoff, and its annual-average recharge rate approximately equals its 2019 annual energy output (TWh/yr) divided by the number of hours per year. Hydro is recharged each time step at this recharge rate. The maximum hydropower energy storage capacity available in all reservoirs is also assumed to equal hydro's 2019 annual energy output. Whereas the present table gives hydro's maximum storage capacity, its output from storage during a given time step is limited by the smallest among three factors: the current energy available in the reservoir, the peak hydro discharge rate multiplied by the time step, and the energy required.

The CW-STES peak discharge rate is set equal to 40% of the annual average cold load (for air conditioning and refrigeration) subject to storage. The ICE storage discharge rate is set to 60% of the same annual average cold load subject to storage. The peak charge rate is set equal to the peak discharge rate.

The HW-STES peak discharge rate is set equal to the maximum instantaneous heat load subject to storage during any 30-second period of the two-year simulation. The values have been converted to electricity assuming the electricity produces heat for heat pumps with a coefficient of performance of 4. Because they are based on maximum rather than the annual average loads, they are higher than the annual-average low-temperature heat loads subject to storage in Table 3. The peak charge rate is set equal to the peak discharge rate.

UTES heat stored in underground soil (borehole storage) or water (water pit or aquifer storage) can be charged with either solar or geothermal heat or excess electricity (assuming the electricity produces heat with an electric heat pump at a coefficient of performance of 4). The maximum charge rate of heat (converted to equivalent electricity) to UTES storage (UTES-heat) is set to the nameplate capacity of solar thermal collectors divided by the coefficient of performance of a heat pump=4). When no solar thermal collectors are used, such as in all simulations here, the maximum charge rate for UTES-heat is zero, and UTES is charged only with excess grid electricity running heat pumps. The maximum charge rate of UTES storage using excess grid electricity (UTES-elec.) is set equal to the maximum instantaneous heat load subject to storage during any 30-second period of the two-year simulation. The maximum UTES heat discharge rate is set equal to the maximum instantaneous heat load subject to storage. The maximum charge rate, discharge rate, and capacity of UTES storage are all in units of equivalent electricity that would give heat at a coefficient of performance of 4.

Figure 1. Keeping the Electric Grid Stable With 100% WWS + Storage + Demand Response

2050-2051 hourly time series showing the matching of all-energy demand with supply and storage in the MRO grid region as a whole. First row: modeled time-dependent total WWS power generation versus load plus losses plus changes in storage plus shedding for the full two-year simulation period. Second row: same as first row, but for a window of 100 days during the simulation. Third row: a breakdown of WWS power generation by source during the window. Fourth row: a breakdown of inflexible load; flexible electric, heat, and cold load; flexible hydrogen load; losses in and out of storage; transmission and distribution losses; changes in storage; and shedding. Fifth row: A breakdown of solar PV+CSP electricity production, onshore plus offshore wind electricity production, building total cold load, and building total heat load (as used in LOADMATCH), summed over each region; Sixth row: correlation plots of building heat load versus wind power output and wind power output versus solar power output, obtained from all hourly data during the simulation. Correlations are very strong for R=0.8-1 (R^2=0.64-1); strong for R=0.6-0.8 (R^2=0.36-0.64); moderate for R=0.4-0.6 (R^2=0.16-0.36); weak for 0.2-0.4 (R^2=0.04-0.16); and very weak for 0-0.2 (R^2=0-0.04) (Evans, 1996). The model was run at 30-s resolution. Results are shown hourly, so units are energy output (TWh) per hour increment, thus also in units of power (TW) averaged over the hour. No load loss occurred during any 30-s interval. Raw GATOR-GCMOM results for solar, wind, heat load, and cold load were provided and fed into LOADMATCH at 30-s time increments. LOADMATCH modified the magnitudes, but not time series, of GATOR-GCMOM results, as described in the main text.

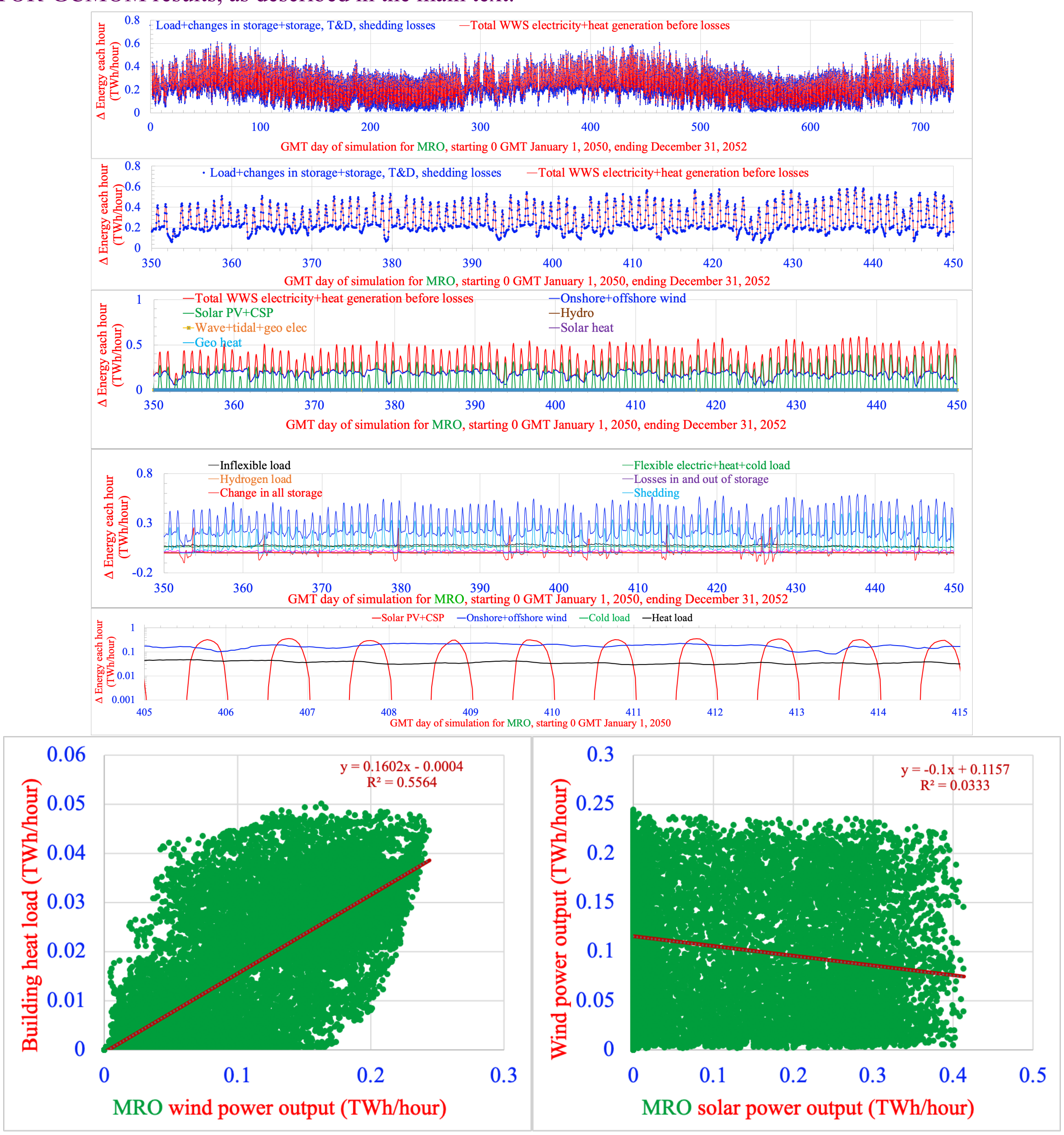

Table 8. Summary of Energy Budget Resulting in Grid Stability

Budget of simulation-averaged end-use power demand met, energy lost, WWS energy supplied, and changes in storage, during the 2-year (17,507.4875 hour) simulations. All units are GW averaged over the simulation and are derived from the data in Table 9 by dividing values from the table in units of TWh per simulation by the number of hours of simulation. TD&M losses are transmission, distribution, and maintenance losses. Wind turbine array losses are already accounted for in the "WWS supply before losses" numbers," since wind supply values come from GATOR-GCMOM, which accounts for such losses. Results are shown for the MRO region as a whole, within which Minnesota is interconnected.

Scenario	(a) Annual average end-use load (GW)	(b) TD&M losses (GW)	(c) Storage losses (GW)	(d) Shedding losses (GW)	(e) End-use load+ losses =a+b+ c+d (GW)	(f) WWS supply before losses (GW)	(g) Changes in storage (GW)	(h) Supply+changes in storage =f+g (GW)
MRO	131.7	13.69	2.82	63.0	211.2	211.2	-0.04	211.2

Table 9. Details of Energy Budget Resulting in Grid Stability

Budget of simulation-total end-use energy demand met, energy lost, WWS energy supplied, and changes in storage, during the 2-year (17,507.4875 hour) simulations. All units are TWh over the simulation. Divide by the number of hours of simulation to obtain simulation-averaged power values, which are provided in Table 8 for key parameters. Results are shown for the MRO region as a whole, within which Minnesota is interconnected.

	MRO
A1. Total end use demand	**2,306**
Electricity for electricity inflexible demand	1,174
Electricity for electricity, heat, cold storage + DR	990
Electricity for H_2 direct use + H_2 storage	142
A2. Total end use demand	**2,306**
Electricity for direct use, electricity storage, + H_2	2,236
Low-T heat load met by heat storage	69
Cold load met by cold storage	0.84
A3. Total end use demand	**2,306**
Electricity for direct use, electricity storage, DR	2,086
Electricity for H_2 direct use + H_2 storage	142
Electricity + heat for heat subject to storage	71
Electricity for cold load subject to storage	6.97
B. Total losses	**1,391**
Transmission, distribution, downtime losses	240
Losses CSP storage	0
Losses PHS storage	0.0014
Losses battery storage	31.3
Losses CW-STES + ICE storage	0.2
Losses HW-STES storage	12.7
Losses UTES storage	5.2
Losses from shedding	1,102
Net end-use demand plus losses (A1 + B)	***3,697***
C. Total WWS supply before T&D losses	**3,698**
Onshore + offshore wind electricity	1,849
Rooftop + utility PV+ CSP electricity	1,786
Hydropower electricity	60.4
Wave electricity	2.39
Geothermal electricity	0
Tidal electricity	0

Solar heat	0
Geothermal heat	0
D. Net taken from (+) or added to (-) storage	**-0.6666**
CSP storage	0
PHS storage	-0.0099
Battery storage	-0.228
CW-STES+ICE storage	-0.0006
HW-STES storage	-0.0098
UTES storage	-0.0294
H_2 storage	-0.389
Energy supplied plus taken from storage (C+D)	***3,697***

End-use demands in A1, A2, A3 should be identical. Generated electricity is shed when it exceeds the sum of electricity demand, cold storage capacity, heat storage capacity, and H_2 storage capacity.

Onshore and offshore wind turbines in GATOR-GCMOM, used to calculate wind power output for use in LOADMATCH, are assumed to be Senvion (formerly Repower) 5 MW turbines with 126-m diameter blades, 100 m hub heights, a cut-in wind speed of 3.5 m/s, and a cut-out wind speed of 30 m/s.

Rooftop PV panels in GATOR-GCMOM were modeled as fixed-tilt panels at the optimal tilt angle of the country they resided in; utility PV panels were modeled as half fixed optimal tilt and half single-axis horizontal tracking. All panels were assumed to have a nameplate capacity of 390 W and a panel area of 1.629668 m^2, which gives a 2050 panel efficiency (Watts of power output per Watt of solar radiation incident on the panel) of 23.9%, which is an increase from the 2015 value of 20.1%.

Each CSP plant before storage is assumed to have the mirror and land characteristics of the Ivanpah solar plant, which has 646,457 m^2 of mirrors and 2.17 km^2 of land per 100 MW nameplate capacity and a CSP efficiency (fraction of incident solar radiation that is converted to electricity) of 15.796%, calculated as the product of the reflection efficiency of 55% and the steam plant efficiency of 28.72%. The efficiency of the CSP hot fluid collection (energy in fluid divided by incident radiation) is 34%.

Table 10. Breakdown of Energy Costs Required to Keep Grid Stable

Summary of 2050 WWS mean capital costs of new electricity plus heat generators; electricity, heat, cold, and hydrogen storage (including heat pumps to supply district heating and cooling), and all-distance transmission/distribution ($ trillion in 2020 USD) and mean levelized private costs of energy (LCOE) (USD ¢/kWh-all-energy or ¢/kWh-electricity-replacing-BAU-electricity) averaged over each simulation. Also shown is the energy consumed per year in each case and the resulting aggregate annual energy cost. Results are shown for Minnesota when its grid is isolated from the outside world. Results are shown for the MRO region as a whole, within which Minnesota is interconnected.

	MRO
Capital cost new generators only ($trillion)	0.706
Cap cost new generators + storage ($trillion)	**0.910**
Components of total LCOE (¢/kWh-all-energy)	
Short-dist. transmission	1.050
Long-distance transmission	0.047
Distribution	2.375
Electricity generators	3.895
Additional hydro turbines	0
Solar thermal collectors	0
LI battery storage	1.008
CSP-PCM + PHS storage	0.000
CW-STES + ICE storage	0.002
HW-STES storage	0.006
UTES storage	0.002
Heat pumps for filling district heating/cooling	0.026
H_2 production/compression/storage	0.284
Total LCOE (¢/kWh-all-energy)	**8.693**
LCOE (¢/kWh-replacing BAU electricity)	8.373
GW annual avg. end-use demand (Table 1)	131.7
TWh/y end-use demand (GW x 8,760 h/y)	1,154
Annual energy cost ($billion/yr)	**100.3**

The LCOEs are derived from capital costs, annual O&M, and end-of-life decommissioning costs that vary by technology (and that are a function of lifetime and a social discount rate for an intergenerational project of 2.0 (1-3)%, all divided by the total annualized end-use demand met, given in the present table.

Capital cost of generators-storage-H_2-HVDC ($trillion) is the capital cost of new electricity and heat generators; electricity, heat, cold, and hydrogen storage; hydrogen electrolyzers and compressors; and long-distance (HVDC) transmission.

Since the total end-use load includes heat, cold, hydrogen, and electricity loads (all energy), the "electricity generator" cost, for example, is a cost per unit all energy rather than per unit electricity alone. The 'Total LCOE' gives the overall cost of energy, and the 'Electricity LCOE' gives the cost of energy for the electricity portion of load replacing BAU electricity end use. It is the total LCOE less the costs for UTES and HW-STES storage, H_2, and less the portion of long-distance transmission associated with H_2.

Short-distance transmission costs are $0.0105 (0.01-0.011)/kWh.

Distribution costs are $0.02375 (0.023-0.0245)/kWh.

Long-distance transmission costs are $0.0089 (0.0042-0.010)/kWh (in USD 2020), which assumes 1,500 to 2,000 km HVDC lines, a capacity factor usage of the lines of ~50% and a capital cost of ~$400 (300-460)/MWtr-km.

Table 11. Energy, Health, and Climate Costs of WWS Versus BAU

2050 Minnesota and MRO annual-average end-use (a) BAU load and (b) WWS load; (c) percent difference between WWS and BAU load; (d) present value of the mean total capital cost for new WWS electricity, heat, cold, and hydrogen generation and storage and all-distance transmission and distribution; mean levelized private costs of all (e) BAU and (f) WWS energy (¢/kWh-all-energy-sectors, averaged between today and 2050); (g) mean WWS private (equals social) energy cost per year, (h) mean BAU private energy cost per year, (i) mean BAU health cost per year, (j) mean BAU climate cost per year, (k) BAU total social cost per year; (l) percent difference between WWS and BAU private energy cost; and (m) percent difference between WWS and BAU social energy cost. All costs are in 2020 USD. H=8760 hours per year.

Scenario	(a)[1] 2050 BAU Annual avg. end-use load (GW)	(b)[1] 2050 WWS Annual avg. end-use load (GW)	(c) 2050 WWS minus BAU load = (b-a)/a (%)	(d)[2] WWS mean total cap-ital cost ($tril 2020)	(e)[3] BAU mean private energy cost ¢/kWh-all energy	(f)[4] WWS mean private energy cost ¢/kWh-all energy	(g)[5] WWS mean annual all-energy private and social cost = bfH $bil/	(h)[5] BAU mean annual all-energy private cost = aeH $bil/y	(i)[6] BAU mean annual BAU health cost $bil/y	(j)[7] BAU mean annual climate cost ($bil/y)	(k) BAU mean annual BAU total social cost =h+i+j $bil/y	(l) WWS minus BAU private energy cost = (g-h)/h (%)	(m) WWS minus BAU social energy cost = (g-k)/k (%)
Minnesota	51.4	22.0	-57.2	0.168	10.30	8.69	16.8	46.4	8.0	61.3	116	-63.9	-85.5
MRO	292.3	131.7	-54.9	0.910	10.30	8.69	100.3	263.8	38.6	369.9	672	-62.0	-85.1

[1]From Table 1.

[2]Capital cost of generators-storage-H_2-HVDC ($trillion) is the capital cost of new electricity and heat generators; electricity, heat, cold, and hydrogen storage; hydrogen electrolyzers and compressors; and long-distance (HVDC) transmission.

[3]This is the BAU electricity-sector cost of energy per unit energy. It is assumed to equal the BAU all-energy cost of energy per unit energy.

[4]The WWS cost per unit energy is for all energy, which is almost all electricity (plus a small amount of direct heat)

[5]The annual private cost of WWS or BAU energy equals the cost per unit energy from Column (f) or (g), respectively, multiplied by the energy consumed per year, which equals the end-use load from Column (b) or (a), respectively, multiplied by 8,760 hours per year.

[6]The 2050 annual BAU health cost equals the number of total air pollution mortalities per year in 2050 from Table 12, Column (a), multiplied by 90% (the estimated percent of total air pollution mortalities that are due to energy) and by a statistical cost of life of $11.56 ($7.21-$17.03) million/mortality (2020 USD) and a multiplier of 1.15 for morbidity and another multiplier of 1.1 for non-health impacts (Jacobson et al., 2019).

[7]The 2050 annual BAU climate cost equals the 2050 CO_2e emissions from Table 12, Column (b), multiplied by the social cost of carbon in 2050 of $548 ($315-$1,188)/metric tonne-$CO_2$ (in 2020 USD), which is updated from values in Jacobson et al. (2019), which were in 2013 USD.

Table 12. Air Pollution Mortalities, Carbon Dioxide Emissions, and Associated Costs

Minnesota and MRO (a) estimated air pollution mortalities per year in 2050-2051 due to anthropogenic sources (90% of which are energy); (b) carbon-equivalent emissions (CO_2e) in the BAU case; (c) cost per tonne-CO_2e of eliminating CO_2e with WWS; (d) BAU energy cost per tonne-CO_2e emitted; (e) BAU health cost per tonne-CO_2e emitted; (f) BAU climate cost per tonne-CO_2e emitted; (g) BAU total social cost per tonne-CO_2e emitted; (h) BAU health cost per unit all-BAU-energy produced; and (i) BAU climate cost per unit-all-BAU-energy produced.

Scenario	(a)[1] 2050 (Deaths/y)	(b)[2] 2050 BAU CO_2e (Mtonne/y)	(c)[3] 2050 WWS ($/ tonne-$CO_2e$-elim-inated)	(d)[4] 2050 BAU energy cost ($/ tonne-$CO_2e$-emitted)	(e)[4] 2050 BAU health cost ($/ tonne-$CO_2e$-emitted)	(f)[4] 2050 BAU climate cost ($/ tonne-$CO_2e$-emitted)	(g)[4] 2050 BAU social cost = d+e+f ($/ tonne-$CO_2e$-emitted)	(h)[5] 2050 BAU health cost (¢/kWh)	(i)[5] 2050 BAU climate cost (¢/kWh)
Minnesota	608	110	152.7	423	73.0	558	1,054	1.78	13.6
MRO	2,931	663	151.4	398	58.3	558	1,015	1.51	14.4

[1]2050 state mortalities due to air pollution are scaled from 2010-12 state values from Jacobson et al. (2015) using the ratio of the total 2050 air pollution mortalities for the U.S. from Jacobson et al. (2019) 53,199/yr (36,394/yr-73,614/yr) to the total 2010-12 number of deaths across the U.S. from Jacobson et al. (2015) 62,381/yr (19,363/yr-115,723/yr).

[2]CO_2e=CO_2-equivalent emissions. This accounts for the emissions of CO_2 plus the emissions of other greenhouse gases multiplied by their global warming potentials.

[3]Calculated as the WWS private energy and total social cost from Table 11, Column (g) divided by the CO_2e emissions from Column (b) of the present table.

[4]Columns (d)-(g) are calculated as the BAU private energy, health, climate, and total social costs from Table 11, Columns (h)-(k), respectively, each divided by the CO_2e emissions from Column (b) of the present table.

[5]Columns (h)-(i) are calculated as the BAU health and climate costs from Table 11, Columns (i)-(j), respectively, each divided by the BAU end-use load from Table 11, Column (a) and by 8760 hours per year.

Table 13. Land Areas Needed

Footprint areas for *new* utility PV farms, CSP plants, solar thermal plants for heat, geothermal plants for electricity and heat, and hydropower plants and spacing areas for new onshore wind turbines.

Scenario	State or region land area (km^2)	Footprint Area (km^2)	Spacing area (km^2)	Footprint area as percentage of state or region land area (%)	Spacing area as a percentage of state or region land area (%)
Minnesota	206,189	287	1,470	0.14	0.71
MRO	1,455,586	3,602	8,704	0.25	0.60

Spacing areas are areas between wind turbines needed to avoid interference of the wake of one turbine with the next. Such spacing area can be used for multiple purposes, including farmland, rangeland, open space, or utility PV. Footprint areas are the physical land areas, water surface areas, or sea floor surface areas removed from use for any other purpose by an energy technology. Rooftop PV is not included in the footprint calculation because it does not take up new land. Conventional hydro new footprint is zero because no new dams are proposed as part of these roadmaps. Offshore wind, wave, and tidal are not included because they don't take up new land. Areas are given both as an absolute area and as a percentage of the state or regional land area, which excludes inland or coastal water bodies. For comparison, the total area and land area of Earth are 510.1 and 144.6 million km^2, respectively.

Table 14. Changes in the Employment

Estimated long-term, full-time jobs created and lost due to transitioning from BAU energy to WWS across all energy sectors when Minnesota is isolated versus interconnected to a larger grid. The job creation accounts for new jobs in the electricity, heat, cold, and hydrogen generation, storage, and transmission (including HVDC transmission) industries. It also accounts for the building of heat pumps to supply district heating and cooling. However it does not account for changes in jobs in the production of electric appliances, vehicles, and machines or in increasing building energy efficiency. Construction jobs are for new WWS devices only. Operation jobs are for new and existing devices. The losses are due to eliminating jobs for mining, transporting, processing, and using fossil fuels, biofuels, and uranium. Fossil-fuel jobs due to non-energy uses of petroleum, such as lubricants, asphalt, petrochemical feedstock, and petroleum coke, are retained. For transportation sectors, the jobs lost are those due to transporting fossil fuels (e.g., through truck, train, barge, ship, or pipeline); the jobs not lost are those for transporting other goods. The table does not account for jobs lost in the manufacture of combustion appliances, including automobiles, ships, or industrial machines.

Scenario	Construction jobs produced	Operation jobs produced	Total jobs produced	Jobs lost	Net change in jobs
Minnesota	79,526	74,419	153,945	50,685	103,260
MRO	474,470	517,868	992,338	416,321	576,017