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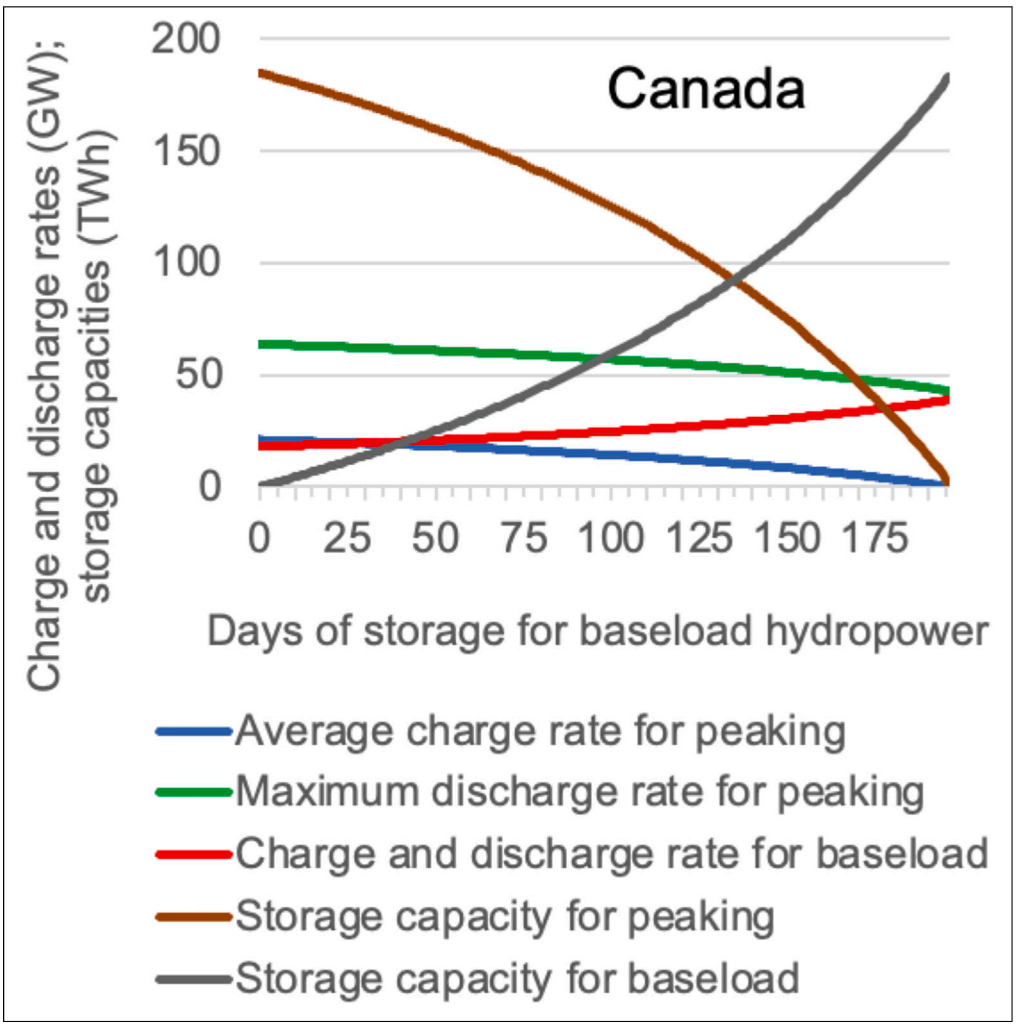

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Highlights

World grid is stability tested with hydropower (CH), batteries (BS), and hydrogen (GHS)

Lowest cost is with CH, CH + BS, or CH + BS + GHS but never CH + GHS or GHS alone

Combining (versus isolating) grid and non-grid hydrogen infrastructure reduces cost

A new method is developed to model hydropower for both peaking and baseload power

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Batteries or hydrogen or both for grid electricity storage upon full electrification of 145 countries with wind-water-solar?

Mark Z. Jacobson[1,2,*]

SUMMARY

Grids require electricity storage. Two emerging storage technologies are battery storage (BS) and green hydrogen storage (GHS) (hydrogen produced and compressed with clean-renewable electricity, stored, then returned to electricity with a fuel cell). An important question is whether GHS alone decreases system cost versus BS alone or BS + GHS. Here, energy costs are modeled in 145 countries grouped into 24 regions. Existing conventional hydropower (CH) storage is used along with new BS and/or GHS. A method is developed to treat CH for both baseload and peaking power. In four regions, only CH is needed. In five, CH + BS is the lowest cost. Otherwise, CH + BS + GHS is the lowest cost. CH + GHS is never the lowest cost. A metric helps estimate whether combining GHS with BS reduces cost. In most regions, merging (versus separating) grid and non-grid hydrogen infrastructure reduces cost. In sum, worldwide grid stability may be possible with CH + BS or CH + BS + GHS. Results are subject to uncertainties.

INTRODUCTION

The world is undergoing an energy revolution: a rapid transition from combustion fuels powering electricity, heat, and mechanical processes to clean, renewable energy sources providing electricity and heat for the same processes. Given that humanity depends on such a transition to address air pollution, global warming, and energy security, it is important to ensure that the new energy system is reliable and inexpensive. One concern with such a system, though, is the uncontrollable variability of wind and solar electricity generation, which gives rise to the need for backup to fill in gaps between supply and demand (load) on the electricity grid.[1]

Historically, most gaps have been filled with conventional hydropower (CH), pumped hydropower storage (PHS), and natural gas. However, a future clean, renewable grid will eliminate natural gas use. And, although PHS sites abound,[2] growth rates of PHS and CH will be limited by zoning impediments in some locations and resource limits in others. It has been hypothesized, therefore, that battery storage (BS) and green hydrogen storage (GHS) (hydrogen produced from clean, renewable electricity, then compressed, stored, and returned to electricity with a fuel cell) may be needed substantially in a future clean, renewable grid.[3–9] Other types of electricity storage, such as concentrated solar power (CSP) with storage, flywheels, compressed air storage, and gravitation storage with solid masses exist but have not taken root to the extent that batteries have to date and GHS is anticipated to in the future. Given the potential large-scale use of BS and GHS in future energy systems, an important question is whether GHS, which has a lower round-trip efficiency, higher cost of discharging electricity, but lower storage capacity cost than BS, results in a lower or higher overall system cost than does BS alone or BS + GHS.

Many studies to date have treated the matching of energy demand with 100% renewable supply and storage for both short and long periods.[8–15] Two studies found that adding turbines to existing CH dams without increasing annual CH electricity generation enables hydropower to be used for meeting short-term peaks in demand and long-term electricity storage needs in the United States and worldwide, respectively.[12,13] Several studies have also found that concatenating 2- or 4-h batteries for both short and long-duration electricity storage enables the matching of demand with supply, storage, and demand response on the grid for multiple years at low cost.[10,11,13,14] Some studies have assumed the use of heat stored seasonally underground and the use of excess renewable electricity to produce that heat.[10–14] Other studies have assumed the use of excess electricity to produce hydrogen for non-grid purposes.[10–17] One study examined the conditions under which GHS is useful in a district energy system.[4] Other studies have treated the use of GHS for grid or non-grid storage.[3–9] Some of these studies compared using BS alone versus BS + GHS in a 100% renewable system in a region, concluding that combining BS with GHS may reduce energy cost in the region.[8,9] A further study has analyzed the impact of electricity storage capacity cost, discharge efficiency, and other parameters on the cost of keeping the grid stable with long-duration storage technologies.[18] However, no study has compared the cost of matching supply with demand, storage, and demand response worldwide upon converting all energy sectors to 100% clean, renewable

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energy and using CH with BS and/or GHS as the main storage options. Also, no study has compared the overall energy cost of isolating versus merging hydrogen electrolyzers and storage for grid versus non-grid purposes.

Here, the cost of matching power demand with supply, storage, and demand response in 24 world regions encompassing 145 countries is examined with a time-dependent trial-and-error simulation model (Methods) run over three years. The predominant electricity storage technologies used are CH with BS and/or GHS. A method is developed to treat CH for both baseload and peaking power. Four cases are examined. In all cases, all energy sectors in each country are first electrified as much as possible and use direct heat for the rest of their energy. The electricity and heat are then provided with 100% wind-water-solar (WWS). Green hydrogen is also used in all four cases for three non-grid purposes: steel manufacturing, ammonia manufacturing, and long-distance transport. This study follows from two previous studies: one in which grid stability was analyzed in 145 countries when green hydrogen was used only for long-distance transport[11] and a second in which green hydrogen was used for long-distance transport and steel and ammonia manufacturing but not for grid electricity.[16]

Results here suggest that four regions need only CH. In the remaining 20 regions, CH + BS is least cost only where the ratio of the needed storage capacity to peak discharge rate is low. In all other regions, where the ratio is usually, but not always, high, CH + BS + GHS is least cost. CH + GHS alone is never least cost. Also, merging electrolyzer and storage equipment for grid and non-grid hydrogen generally reduces cost versus separating such equipment. Thus, using existing CH for baseload and peaking together, with either BS alone or with BS + GHS, can help power the world with 100% clean, renewable energy. This new information should help planners create a more efficient and cost-effective future energy system. Results are subject to uncertainties, including whether they may change when a simulation model (this study) versus an optimization model is used (see limitations of the study).

Simulations: Four cases compared

This work is carried out through computer modeling. Simulations are run with LOADMATCH[10–14,16] (Methods and Notes S3–S7), a model that matches time-dependent electricity, heat, cold, and hydrogen demand with supply, storage, and demand response. LOADMATCH is modified here to treat GHS as an additional grid electricity storage option beyond CH, PHS, CSP with storage, and BS, which are already treated (Table S2). The processes added for GHS are hydrogen production and compression with WWS grid electricity, hydrogen storage for grid electricity, and conversion of stored hydrogen back to grid electricity with fuel cells. The model also treats green hydrogen for steel and ammonia manufacturing and long-distance transport.[16] Table S7 summarizes the 2050 hydrogen budget needed by country for each of these non-grid uses. LOADMATCH is further modified here to treat CH for both baseload and peaking power. Previously, it was used only to provide peaking power. A set of six equations and six unknowns is solved (Equations S7–S12) to distribute CH parameters between peaking and baseload power while conserving several properties (Note S5).

BS and GHS each has advantages and disadvantages. The advantages of batteries for grid electricity storage are that they (1) emit no air pollutants when charging if the electricity charging them is from a clean, renewable source and no air pollution ever when discharging; (2) charge and discharge rapidly (100% discharge in 10–20 ms[7] versus 100% in 5 min for an open-cycle natural gas turbine[19] and 15 s for CH[20]); (3) provide, when concatenated together, substantial peaking power for a short period, or low power for days to weeks to months, or anything in between[10,11]; (4) do not take up much space or have the same zoning impediments as CH or PHS; and (5) can save grid operators substantial money compared with natural gas turbines due to providing frequency control ancillary service and contingency reserve service more effectively than can natural gas.[21] Disadvantages of BS are its (1) high capital cost per kWh of storage capacity, (2) degradation over time, and (3) requirement, in many cases, for metals that must be mined or obtained from recycling. However, battery cost has declined and battery degradation has decreased in the past decade. For example, at least one manufacturer warranties batteries now for 15,000 cycles or 15 years.[22] Finally, whereas lithium used in most batteries is mined, it is also recycled.[22,23]

Advantages of GHS are that (1) electrolyzers result in no air pollutants during hydrogen production if the electricity source is clean and renewable, and fuel cells produce only water vapor during electricity generation; (2) electrolyzers create hydrogen rapidly, and fuel cells produce electricity within seconds to a minute[7]; (3) GHS can provide peaking power for a short period, or low power for days to weeks to months, or anything in between[4]; (4) GHS requires only modest space and does not face the same zoning problems as CH or PHS; (5) GHS may save grid operators money like batteries do, and (6) GHS' costs per unit storage capacity are lower than those of batteries.

Disadvantages of GHS are as follows: (1) the round-trip efficiency of BS is 2.3–4 times that of GHS,[20] (2) the cost per kWh of discharging electricity from GHS is higher than that from BS; (3) hydrogen from GHS may leak, impacting the atmosphere; and (4) platinum, needed in electrolyzers and fuel cells, may be a limiting factor in GHS growth. The cost issues are evaluated here. With respect to leakage, gasoline vehicles already emit hydrogen. Even if all vehicles worldwide are transitioned to hydrogen fuel cell vehicles, the hydrogen leakage rate needs to exceed 3% for hydrogen emissions to exceed those of gasoline vehicles.[24] Instead, most vehicles will be replaced by battery electric ones, suggesting a large reduction in hydrogen emissions upon a world transition to clean, renewable energy. Also, hydrogen leak rates are expected to be less than 1%, as most hydrogen will be produced near where it is consumed (so few pipelines will be needed), hydrogen infrastructure will be new and designed to eliminate leaks, and hydrogen will not be mined like natural gas is, reducing a major source of leaks. With respect to platinum, it is also used in catalytic converters in gasoline vehicles. Because a transition will eliminate gasoline vehicles, platinum will no longer be needed for catalytic converters. Thus, platinum should not be a limiting factor in hydrogen use.

It is assumed here that hydrogen used for grid electricity will be stored as a compressed gas. More expensive and energy-intensive liquefied hydrogen storage is needed only when space is a constraint, such as when hydrogen is used in rockets or airplanes. Liquid hydrogen is also needed when hydrogen is transported by ship. However, this study assumes that electricity is transmitted and electrolytic hydrogen is produced and stored at steel and ammonia factories and long-distance transport hubs (e.g., airports, docks, train stations, major truck stops, and military bases), minimizing the need for hydrogen piping or shipping. As such, liquefied hydrogen is not treated here for GHS. Similarly, liquid organic hydrogen carriers,[25] which have been proposed to transport hydrogen by pipeline and ship and which require more chemicals and energy than does compressed hydrogen, are not treated here.

Four simulations are run with LOADMATCH for each of 24 world regions (Table S1). The regions include a mix of nine multi-country regions (Africa, Central America, Central Asia, China region, Europe, India region, the Middle East, South America, and Southeast Asia) and 15 individual countries or pairs of countries (Australia, Canada, Cuba, Haiti-Dominican Republic, Israel, Iceland, Jamaica, Japan, Mauritius, New Zealand, the Philippines, Russia-Georgia, South Korea, Taiwan, and the United States). The 145 countries in these regions emit over 99.7% of the world's fossil-fuel CO_2.

The first simulation (Case I) is a baseline simulation in which non-grid hydrogen is used for steel and ammonia manufacturing and long-distance transport, but GHS is not treated. Instead, grid electricity storage includes only CH, BS, PHS, and/or CSP, assuming the maximum charge rates, discharge rates, storage capacities, and storage times in Table S15. Many types of batteries exist that can be used for grid electricity storage. These types include lithium-ion, lithium-iron-phosphate (LFP), iron-air, basalt-stone, sodium-sulfur, aluminum-ion, salt-water, and vanadium flow batteries, among others. Here, we assume the use of 4-h batteries with the measured efficiency of a 2021 lithium-ion Tesla Powerpack and a projected 2035 cost per kWh of lithium-ion batteries given in Table S27. WWS supply profiles are described in Note S3, demand profiles are described in Note S6, and both are graphed for each region and for the same 3-year period as here in Figure S1 of Jacobson et al.[16]

Case II is the same as Case I, except that in Case II, GHS is treated along with all the electricity storage options treated in Case I. In Case II, the same rectifiers, electrolyzers, compressors, and storage tanks are used for non-grid hydrogen as for GHS, and fuel cells are added to reproduce grid electricity from the communally stored hydrogen. Sharing hydrogen production and storage for both grid and non-grid purposes is expected to reduce costs due to economies of scale, a hypothesis that is tested here. Case II also assumes that electrolytic hydrogen is produced and stored at steel and ammonia factories and long-distance transport hubs. Fuel cells are located at these hubs and can feed electricity back to the grid from them. Aside from the addition of GHS, the only other difference between Cases I and II is that GHS replaces some BS in Case II. The replacement is limited by the fact that no changes in the nameplate capacities of WWS electricity generators or of heat, cold, or other electricity storage are permitted in Case II versus Case I. Table S19 and Figures S2 and S3 provide the BS and GHS characteristics in Case II for each region.

Case III is the same as Case II, except in Case III, different rectifiers, electrolyzers, compressors, and storage tanks are used for non-grid versus grid hydrogen, and fuel cells re-produce grid electricity only from the hydrogen stored in the grid-hydrogen storage tanks. These storage tanks do not need to be located at steel or ammonia manufacturing facilities or at a transport hub. They can be placed in other locations. Table S20 provides the BS and GHS characteristics in Case III.

In Case IV, GHS replaces all BS. The only way stable solutions are found in this case (with zero batteries) is with higher nameplate capacities of GHS equipment and, in most cases, of WWS generators, than in Cases I–III, driving up cost. Table S11 provides the difference in nameplate capacities by region in Case IV versus Cases I–III. Table S21 provides the GHS system characteristics in Case IV.

RESULTS

LOADMATCH is run for three years (2050–2052) with a 30-s timestep for Cases I–IV in each of the 24 world regions encompassing 145 countries (Table S1). In four of the 24 regions (Canada, Iceland, Russia region, and South America), BS is not needed to keep the grid stable, so GHS is not needed either. In those regions, an abundance of WWS resources (CH used for storage and generation plus wind and/or solar) avoids the need for BS. Because no BS or GHS is needed, results are the same in all four cases in those four regions.

In five of the remaining 20 regions, CH + BS alone (Case I) results in the lowest annual private energy cost relative to CH + BS + GHS (Cases II and III) or CH + GHS alone (Case IV) (Table 1; Figure 2). This occurs despite the fact that including GHS in Cases II and III reduces the nameplate capacity of BS needed by about half, from 17.2 TW/68.9 TWh in Case I to 8.8 TW/35.3 TWh in Case II and to 8.2 TW/32.9 TWh in Case III (Figure 1; Tables S18–S21).

The annual private cost of energy in Case II (CH + BS + GHS, where non-grid and grid hydrogen production and storage are merged) is lower than in all other cases in 11 regions, lower than in Case I in 14 regions, and lower than in Case III in 12 regions (Table 1; Figure 2). However, averaged over all 24 regions, Case II has a 1% higher annual cost of energy than Case I, due largely to the 6.1% higher cost of energy in Case II in the China region. The greatest percent cost reduction in Case II versus Case I (11.5%) occurs in Israel (Table 1). From a technology point of view, the cost increase among all regions in Case II versus Case I is attributable to a 49% reduction in the battery peak discharge rate and storage capacity among all regions offset by the addition of 1.12 GW of fuel cells, a 107% increase in hydrogen storage tank size (5.59–11.5 Tg-H_2), and a slight (0.3%) increase in electrolyzer plus compressor nameplate capacity (7.05 TW–7.07 TW) (Tables S18–S21).

The annual private cost of energy in Case III (CH + BS + GHS, where non-grid and grid hydrogen production and storage are separated) is lower than in all other cases in four regions, lower than in Case I in 10 regions, and lower than in Case II in eight regions (Table 1; Figure 2). Among all regions, Case III increases the annual private energy cost relative to Case I by 0.25%, which is less than the increase in Case II relative to Case I (Table 1). This slight overall cost increase in Case III is attributable to a 52.3% reduction (in Case III relative to Case I) in the battery peak discharge rate (17.23–8.22 TW) and capacity (68.9–32.9 TWh), offset by 1.12 GW greater fuel cell capacity, a 71% larger hydrogen storage tank size (9.56 instead of 5.59 Tg-H_2), and a 16% larger electrolyzer plus compressor nameplate capacity (8.17 instead of 7.05 TW) (Tables S18–S21). In sum, isolating the sources and storage of grid and non-grid hydrogen (Case III) increases annual private energy cost in more locations than merging such sources and storage (Case II) but increases overall annual private energy cost less than does Case II (Table 1).

Table 1. 2050 (a) end-use demand, (b)-(e) mean capital cost of an all-sector transition to WWS in Cases I-IV, (f)-(i) mean levelized cost of all-sector energy (LCOE) in WWS Cases I-IV, (j)-(m) mean annual all-energy private cost in WWS Cases I-IV; (n) mean annual all-energy private cost in the BAU case; and (o) Rideal = the ideal ratio of a battery's maximum storage capacity (TWh) to its discharge rate (TW) (thus a battery's ideal number of hours of storage), obtained by taking the ratio of the actual battery storage capacity in Case I to the maximum discharge rate actually occurring during each simulation in that case. All costs are in 2020 USD. Costs in italics are the lowest cost among all cases in the region.

	WWS annual-average end-use demand (GW)	WWS mean capital cost ($tril)				WWS mean LCOE (¢/kWh-all energy)				WWS mean annual all-energy private = social cost ($bil/y)				BAU mean annual all-energy private cost ($bil/y)	R_{ideal} (h)
Region	(a) All cases	(b) Case I	(c) Case II	(d) Case III	(e) Case IV	(f) Case I	(g) Case II	(h) Case III	(i) Case IV	(j) Case I	(k) Case II	(L) Case III	(m) Case IV	(n) BAU	(o) Case I
Africa	482.1	3.627	3.604	3.639	4.166	8.63	8.55	8.67	9.85	364.5	*361.2*	366.0	416.0	1,222	6.3
Australia	92.3	0.618	0.611	0.687	0.816	8.45	8.37	9.36	10.27	68.3	*67.7*	75.6	83.0	188.0	9.5
Canada	170.3	0.654	0.654	0.654	0.654	6.57	6.57	6.57	6.57	98.1	98.1	98.1	98.1	311.3	–
Central America	156.5	1.445	1.331	1.358	1.548	10.85	10.17	10.41	10.94	148.8	*139.5*	142.7	150.0	347.6	27.0
Central Asia	166.9	1.077	1.090	1.086	1.108	7.95	8.05	8.03	8.19	*116.3*	117.7	117.4	119.7	402.7	4.5
China region	2,424	14.44	15.45	14.64	15.72	8.16	8.66	8.26	8.82	*1,733*	1,838	1,754	1,873	4,248	5.1
Cuba	9.0	0.103	0.099	0.098	0.131	12.15	11.84	11.86	15.00	9.57	*9.32*	9.34	11.8	16.1	39.5
Europe	958.3	5.785	5.997	5.777	6.097	8.46	8.76	8.46	8.88	710.0	735.1	*709.9*	745.8	2,005	5.5
Haiti region	7.6	0.055	0.055	0.056	0.087	8.72	8.67	8.87	12.61	5.81	*5.78*	5.91	8.40	18.3	11.8
Iceland	3.2	0.003	0.003	0.003	0.003	7.07	7.07	7.07	7.07	1.96	1.96	1.96	1.96	3.7	–
India region	1,007	6.892	6.723	7.056	7.527	8.17	8.05	8.48	9.01	720.9	*710.2*	748.0	794.4	1,740	16.4
Israel	12.8	0.141	0.120	0.111	0.150	12.46	10.96	10.44	13.55	13.9	12.3	*11.7*	15.2	25.6	56.0
Jamaica	2.6	0.025	0.024	0.025	0.029	10.57	10.44	10.65	12.22	2.37	*2.34*	2.38	2.74	5.5	22.6
Japan	186.3	1.311	1.293	1.293	1.371	9.39	9.32	9.32	9.56	153.2	*152.08*	152.13	156.0	326.3	13.0
Mauritius	1.9	0.018	0.019	0.019	0.021	11.75	12.14	12.56	13.46	*1.95*	2.01	2.08	2.23	4.8	25.1
Middle East	706.5	4.523	4.502	4.479	4.545	8.05	8.03	8.03	8.19	498.3	497.3	*496.7*	507.0	1,517	12.2

(*Continued on next page*)

Table 1. ***Continued***

Region	WWS annual-average end-use demand (GW)	WWS mean capital cost ($tril)				WWS mean LCOE (¢/kWh-all energy)				WWS mean annual all-energy private = social cost ($bil/y)				BAU mean annual all-energy private cost ($bil/y)	R_{ideal} (h)
	(a) All cases	(b) Case I	(c) Case II	(d) Case III	(e) Case IV	(f) Case I	(g) Case II	(h) Case III	(i) Case IV	(j) Case I	(k) Case II	(L) Case III	(m) Case IV	(n) BAU	(o) Case I
New Zealand	16.7	0.098	0.096	0.096	0.096	8.47	8.37	8.38	8.39	12.39	*12.251*	12.254	12.27	23.0	4.1
Philippines	41.0	0.412	0.419	0.413	0.482	10.85	11.32	11.06	12.58	*39.0*	40.7	39.7	45.2	83.8	18.4
Russia region	268.3	1.317	1.317	1.317	1.317	7.40	7.40	7.40	7.40	174.0	174.0	174.0	174.0	702.4	–
South America	468.7	3.124	3.124	3.124	3.124	8.89	8.89	8.89	8.89	365.1	365.1	365.1	365.1	806.4	–
Southeast Asia	584.6	7.183	7.214	7.195	8.362	12.48	12.54	12.52	14.58	*639.3*	642.1	641.3	746.8	1,183	11.8
South Korea	154.4	1.830	1.734	1.746	2.003	12.85	12.32	12.46	13.75	173.8	*166.7*	168.5	185.9	281.2	30.1
Taiwan	89.9	0.983	0.802	0.839	0.970	12.07	10.17	10.64	11.81	95.0	*80.1*	83.8	93.0	153.5	58.1
United States	959.5	6.667	6.476	6.456	7.758	8.92	8.74	8.72	10.19	749.8	734.5	*733.3*	856.4	2,189	15.4
All regions	**8,970**	**62.33**	**62.75**	**62.17**	**68.08**	**8.78**	**8.87**	**8.80**	**9.50**	**6,895**	**6,966**	**6,912**	**7,464**	**17,805**	

All costs are in 2020 USD. Costs in italics are the lowest cost among all cases in the region.

The four cases are defined as follows: Case I (baseline): no hydrogen is used for grid electricity but hydrogen is used for non-grid purposes (steel and ammonia manufacturing and long-distance transport); Case II: hydrogen is used for both grid and non-grid purposes, but hydrogen rectifiers, electrolyzers, compressors, and storage tanks are shared for both purposes, and fuel cells are used to produce grid electricity when needed from the communal hydrogen storage; Case III: same as Case II, except that unique rectifiers, electrolyzers, compressors, and storage tanks are used for grid versus non-grid hydrogen, and fuel cells are used to produce grid electricity when needed from the grid hydrogen storage; and Case IV: same as Case II, except all batteries for grid electricity storage are replaced by GHS. The end-use demand is the same in all four cases.

The mean annual all-energy private costs in Cases I–IV used in column (n) are from Table S36. Battery storage capacity in Case I is from Table S18. The maximum discharge rate actually occurring during each simulation is from Table S17.

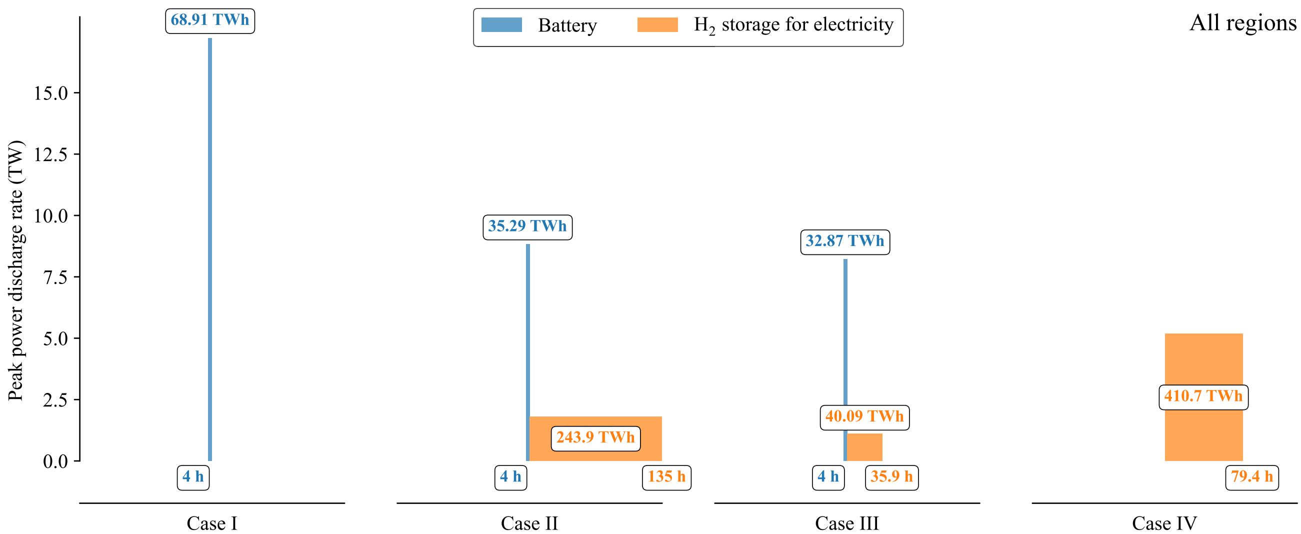

Figure 1. Peak power discharge rate, peak storage capacity, and hours of storage at the peak discharge rate for battery storage and green hydrogen storage in each Case I–IV, for the sum of 20 world regions in which battery storage for grid electricity is needed in this study

Figures S2 and S3 and Tables S18–S21 show results for each individual region. The number of hours of storage equals the storage capacity divided by the peak power discharge rate. In Case I, no GHS is used for grid electricity, and in Case IV, no BS is used. In Case II, the hydrogen storage is communal for grid and non-grid hydrogen. The storage capacity in that case is that of the communal storage, and the peak power discharge rate is the nameplate capacity of the fuel cell discharging for grid electricity. Thus, the number of hours of storage is the time it takes to fully discharge the communal storage at the peak discharge rate as if it is being discharged solely for grid electricity. In Case III, the hydrogen storage capacity is solely that of hydrogen for grid electricity, and the fuel cells used for grid electricity consume only that hydrogen. Case IV is the same as Case II, except with no batteries.

From Tables S18–S21, Case III requires greater electrolyzer and compressor nameplate capacities than does Case II. This is due to the need to produce hydrogen separately for non-grid versus grid storage in Case III. However, Case III requires lower hydrogen and battery storage capacities and battery peak discharge rates than does Case II. In Case II, the GHS peak discharge rate among all regions is 20.5% that of BS, but the GHS storage capacity for grid plus non-grid hydrogen is 6.9 times that of BS. In Case III, the GHS peak discharge rate is 13.6% that of BS, but the GHS storage capacity for only grid electricity storage is only 1.2 times that of BS (Figure 1; Table S19). Thus, in both Cases II and III, BS is used primarily for its peak discharging ability, whereas GHS is used primarily for its storage capacity.

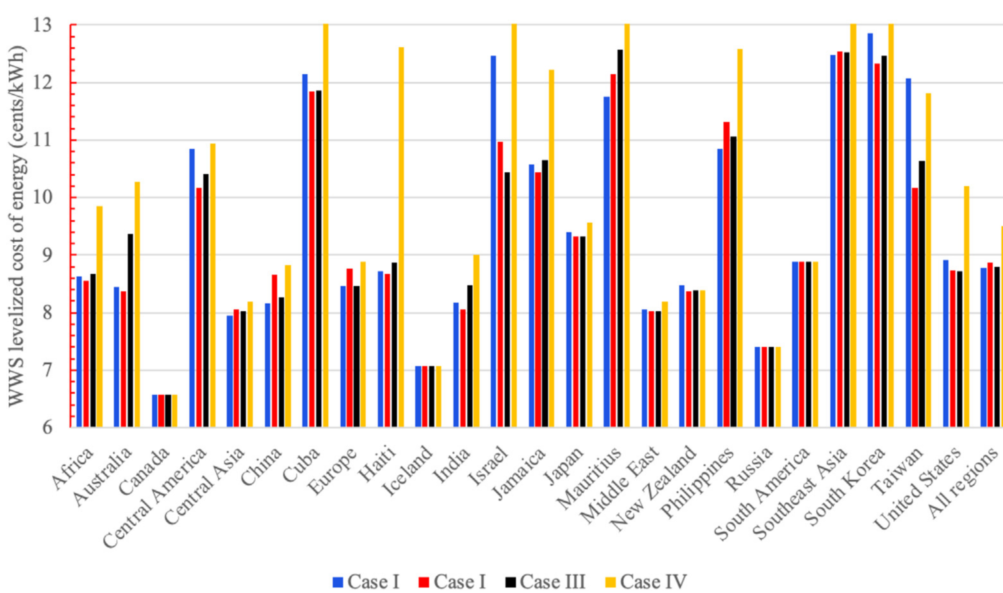

Figure 2. 2050 mean levelized cost of all WWS energy in Cases I–IV (2020 USD)

Table 1 contains the numerical data. Tables S33–S35 contain a breakdown of the levelized costs by component for each region and case.

Case IV (using CH with BS but without GHS) never results in the lowest annual energy cost (Table 1). This is because the cost of obtaining the peak discharge rates needed in each region is higher for GHS alone than for BS alone or BS + GHS. Also, in many regions, additional wind or solar electricity generators are needed to provide sufficient energy to power GHS due to the low round-trip efficiency of GHS compared with BS. Only in New Zealand and Taiwan is using CH + GHS (Case IV) less expensive than using CH + BS (Case I), but even in those regions, CH + GHS is more expensive than CH + BS + GHS (Cases II and III).

A result found here, that using CH + BS + GHS reduces the cost of a 100% renewable energy system versus CH + BS (in 15 of the 20 regions where BS is used), is supported by Auguadra et al.,[8] who found the same result for Spain with an optimization model. The result is also supported by Marocco et al.,[9] who found that using BS with GHS reduced system cost by ∼35% compared with BS alone for the Froan Islands, Norway. That study concluded that including GHS allows the battery and renewable generators not to be oversized due to the low cost of the long-term storage capability of GHS.

An important component of the overall energy cost is the cost of producing and storing hydrogen and fuel cells. Tables S28–S32 indicate that, averaged over all regions, the mean costs of hydrogen plus fuel cells are \$6.50/kg-H_2, \$7.27/kg-H_2, \$7.35/kg-H_2, and \$7.44/kg-H_2 for Cases I–IV, respectively. In Case III, where separate electrolyzers and storage are used for non-grid versus grid hydrogen, the mean cost of grid hydrogen alone is \$19.1/kg-H_2 whereas that for non-grid hydrogen is \$6.798/kg-H_2. Because 202 Tg-H_2/y is needed for non-grid hydrogen but only 9.66 Tg/y is needed for grid hydrogen, the overall cost of hydrogen in Case III is \$7.35/kg-H_2, which is higher than in Case II (\$7.27/kg-H2), where non-grid and grid hydrogen production and storage are merged. Electricity cost comprises the largest fraction of hydrogen cost in most cases, followed by electrolyzer cost, storage cost, fuel cell cost, dispensing and fueling cost (for transport), compressor cost, and water cost. Water cost per unit mass of hydrogen is assumed constant in all regions, but in reality, water availability and cost vary by region. On the other hand, electrolyzers may now use seawater to produce hydrogen,[26] expanding the ease of obtaining water for electrolytic hydrogen. Even when water is relatively expensive, though, its high cost has little impact on overall cost because water is only a small component of overall electrolytic hydrogen cost.

DISCUSSION

So, why is CH + BS alone the low-cost option in 5 of the 20 regions that need BS, whereas CH + BS + GHS is the low-cost option in the rest? One reason can be seen from BS versus GHS costs and efficiencies. A second reason can be seen from the ratio of the battery storage capacity to the actual peak discharge rate of batteries during Case I simulations (Table 1).

First, the round-trip efficiency of BS (∼90%, Table S27) is much higher than that of GHS (∼45%, Tables S26). In addition, the cost of discharging batteries (∼\$240/kW, Table S27) in 2035 is projected to be lower than that of discharging fuel cells (∼\$500/kW, Table S26). However, the storage capacity cost of batteries (∼\$60/kWh, Table S27) in 2035 is expected to exceed that of GHS (∼\$12/kWh, Table S26). Because all batteries in this study are concatenated 4-h batteries (individually supplying electricity for 4 h at their peak discharge rate), batteries will be used optimally in a region when the ratio of their summed capacity (TWh) to their summed-peak discharge rate actually occurring during a simulation (TW) is close to 4 h. This ratio is called R_{ideal}. It is the ideal ratio of a battery's capacity to peak discharge rate (the ideal number of hours of battery storage at the battery's actual, not nameplate, peak discharge rate). If R_{ideal} is much higher than 4 h (e.g., 60 h), then the concatenated batteries in the region are being used mostly for long-term storage and less for their peak power discharging ability. Batteries can be used for long-term storage because, when concatenated together, they can discharge at low power for a long period or at their summed nameplate capacity for 4 h, or anything in between.[10,11] Because BS is more expensive per kWh than is GHS, replacing some BS with GHS should lower total cost when R_{ideal} is high. On the other hand, when R_{ideal} is low (close to 4 h), BS is being used for both peaking and storage, so the addition of GHS usually drives cost up because of the low round-trip efficiency of GHS coupled with its high cost of discharging electricity. Thus, when R_{ideal} is low, significantly more peaking power is needed for short periods than when R_{ideal} is high.

Table 1 shows R_{ideal} values from Case I. In all 5 regions in which BS alone (Case I) results in lower private annual cost than do Cases II–IV, R_{ideal} < 25.1 h. In all 5 regions where R_{ideal} > 25.1 h, Cases II and III result in lower cost than Case I. In those regions, the lower cost of GHS capacity outweighs its lower efficiency and its higher cost of discharging electricity compared with BS. However, in 10 regions where R_{ideal} < 25.1 h, Case II and/or Case III also result in lower cost than Case I. Thus, whereas a high value of R_{ideal} (>25.1 h) appears to be a good indicator (100% accuracy in the five regions where that occurred) of when BS should be combined with GHS, a low value (<25.1 h) is less accurate, predicting BS alone is the best option only ∼33% of the time (in 5 out of the 15 regions).

In Cases II and III, the nameplate capacities of all generators and of storage aside from BS and GSH are the same as in Case I. The cost reduction due to replacing some BS with GHS without changing the nameplate capacity of anything else, when R_{ideal}>25.1, can be explained with results for an individual region, South Korea. In that region, R_{ideal}∼30.1 h, and a mixture of GHS and BS (Case III) costs less than BS alone (Case I) (Table 1). This occurs for the following reason: 1,060 GW/4.24 TWh of BS in Case I is replaced, in Case III, with 220 GW/0.88 TWh of BS, 80 GW of electrolyzers and compressors, and 80 GW/4.0 TWh of fuel cells/hydrogen storage (thus 50 h of hydrogen storage) (Tables S18–S21). Thus, the overall storage capacities are similar in both cases (4.24 TWh in Case I versus 4.88 TWh in Case III), but the peak discharge rate in Case III (300 GW) is less than one-third that in Case I (1,060 GW). Overall, fewer 4-h batteries combined with 50 h of hydrogen storage (Case III) costs less than more 4-h batteries with no GHS (Case I). The BS in Case III is still needed for most all of its peaking capacity and a quarter of its storage capacity. In Case III, GHS is not needed much for peaking, but it supplies the other three-quarters of the storage capacity at a lower cost than BS supplies its storage capacity.

CH + GHS (Case IV) is more expensive in all regions (Table 1) than is either CH + BS (Case I) (aside from in New Zealand) or CH + BS + GHS (Cases II and III) (all regions) because GHS alone is too inefficient and costly to supply the peak discharge that BS or a combination of BS + GHS can supply.

In sum, when the ratio (R_{ideal}) of the battery storage capacity to the actual peak discharge rate needed in a region is high, a combination of BS for most peak discharging and for some storage capacity and GHS for the remaining peak discharging and most storage capacity is beneficial. Otherwise, when R_{ideal} is low, then BS alone or BS + GHS is always the best option. GHS alone is never the best option. R_{ideal} tends to be high (longer-duration GHS storage is helpful) in regions with either low hydropower resources, weak wind or solar resources, or low peaks in demand. Table S17 shows that combining CH with GHS and BS (Cases II and III) reduces R_{ideal} compared with CH + BS alone (Case I). For example, for Taiwan, R_{ideal} decreases from 58.1 to 8.8 h by including GHS. Thus, using GHS together with BS reduces the need for batteries for storage while maintaining their need for peaking.

Finally, because existing CH + BS dominates energy storage in Case I and CH + BS + GHS dominates storage in Cases II and III, and all three cases result in lower-cost solutions relative to BAU than Case IV (CH + GHS), another major finding of this study is that the 145 countries examined may be powered at low cost primarily by existing CH + BS or CH + BS + GHS.

Limitations of the study

The results here are subject to several uncertainties. First, because LOADMATCH is a trial-and-error simulation model (Methods) that finds low-cost solutions by repeating simulations under different conditions, rather than an optimization model that determines the least cost computationally, how do we know that the solutions here are truly low-cost solutions? In response, the issue examined here is not whether a solution with BS or GHS or both provides the lowest-overall system cost among all possible scenarios, it is whether a system designed around CH + BS alone (Case I) or CH + BS + GHS (Cases II–III) provides a lower cost solution than a system designed around CH + GHS (Case IV). With that in mind, the first question is whether a lower-cost solution can be obtained in Case I (CH + BS) versus Case IV (CH + GHS). The second question is whether CH + BS + GHS (Cases II–III) lowers the cost further relative to Cases I or IV. Case I is established by designing a system around BS. In Case IV, all BS is replaced by GHS. Thus, the system is designed around GHS rather than BS. The result is zero batteries but higher nameplate capacities of hydrogen equipment and, in most cases, WWS generators, than in Case I, driving up cost in all but two regions relative to Case I (Table 1). An optimization model would likely come to the same conclusion regarding Case IV, given that BS and GHS both perform the exact same function, but GHS needs more input energy due to its low round-trip efficiency.

Similarly, in Cases II and III, all generator nameplate capacities and other parameters aside from BS and GHS are the same as in Case I, and GHS replaces some BS. Thus, whether CH + BS + GHS (Cases II and III) can lower cost versus CH + BS (Case I) is just a question of the cost of each simulation in Cases II and III. An optimization would adjust multiple parameters simultaneously to provide the lowest-cost overall solution. However, an optimization cannot determine whether using CH+GHS+BS (Cases II and III) gives a lower cost than CH + BS (Case I) while holding all other parameters constant unless that constraint is included. If it is, then the result should be the same as in the present case. Indeed, other studies using optimization models under different circumstances than here have concluded the same as found here, that combining BS with GHS often reduces cost relative to BS alone.[8,9] In sum, it is not expected that using an optimization model will change the conclusions here, but future work will help to confirm this.

A second uncertainty is what the 2050 costs of BS and GHS will be compared with what was assumed in this study. In response, the conclusions here should continue to apply so long as the round-trip efficiency of BS exceeds that of GHS, the cost of discharging electricity from a battery continues to be lower than the cost of discharging from a fuel cell, and the cost per kWh of hydrogen storage continues to be less than that of battery storage.

To illustrate how changes in 2050 BS and GSH costs relative to what was assumed here could affect results, two sensitivity tests are run: one for the United States and the second for Southeast Asia. For the United States, the baseline annual private energy cost in Case II (CH + BS + GHS) is lower than in Case I (CH + BS), so CH + BS + GHS is less expensive than CH + BS alone. However, reducing the mean baseline battery cost from \$60/kWh (Table S27) to \$15/kWh causes the cost in Case I to fall below that in Case II, so CH + BS is now less expensive than CH + BS + GHS. For Southeast Asia, the baseline annual private energy cost in Case I is less than in Case II. Thus, CH + BS is less expensive than CH + BS + GHS. However, a decrease in the mean baseline hydrogen fuel cell cost from \$500/kW (Table S26) to \$200/kW decreases the annual energy cost in Case II relative to Case I, so CH + BS + GHS is now less expensive than CH + BS. Because both of these sensitivity test costs are conceivable, a big uncertainty in this study is the actual future cost of BS and GHS.

Finally, an important question is whether batteries with more than 4 h of storage at their peak discharge rate will affect the results found here. In response, longer-duration batteries can only increase the cost of scenarios that include BS unless the cost of longer-duration battery is much less per kWh than that of a 4-h battery. In other words, at the same cost per kWh, two 4-h batteries are always more useful and versatile than one 8-h battery. The reason is that, for example, two 10 kWh, 4-h batteries, when concatenated together, provide the exact same storage capacity as one 20 kWh, 8-h battery. However, the two 4-h batteries provide a peak discharge rate of 5 kW (=2 batteries x 10 kWh/4 h), whereas the 8-h battery provides a peak discharge rate of only 2.5 kW (=20 kWh/8 h). Thus, to obtain the same peaking power as the two 4-h batteries, two 8-h batteries are needed, doubling the cost of batteries. Thus, so long as two 4-h batteries cost the same per kWh as one 8-h battery, there is only a benefit (a higher peak discharge rate) and no disbenefit of using 4-h batteries.

STAR★METHODS

Detailed methods are provided in the online version of this paper and include the following:

- KEY RESOURCES TABLE
- RESOURCE AVAILABILITY
  - Lead contact
  - Materials availability
  - Data and code availability
- METHOD DETAILS

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.isci.2024.108988.

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AUTHOR CONTRIBUTIONS

Conceptualization, methodology, investigation, software, writing, review, and editing, M.Z.J.

DECLARATION OF INTERESTS

The author declares no competing interests.

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STAR★METHODS

KEY RESOURCES TABLE

REAGENT or RESOURCE	SOURCE	IDENTIFIER
Software and algorithms		
Spreadsheet model for 145 countries	This paper	http://web.stanford.edu/group/efmh/jacobson/Articles/I/145-H2/145-H2-study.xlsx
Mathematical solution to solving a set of six equations and six unknowns to represent conventional hydropower	This paper	The solution is provided in the supplemental information file
Results among all regions examined	This paper	Output data for all regions examined are provided in the multiple tables and figures in the supplemental information file

RESOURCE AVAILABILITY

Lead contact

Further information and requests can be directed to the lead contact, Prof. Mark Z. Jacobson (jacobson@stanford.edu).

Materials availability

This study did not generate new physical materials.

Data and code availability

- The supplemental information contains most results. Additional results, including data going into all figures and tables, are available from the lead contact.
- The spreadsheet model used for this study is publicly available online.[27] The new mathematical solution here for peaking and baseload power from conventional hydropower is provided in this paper's supplemental information. This study did not develop the original GATOR-GCMOM or LOADMATCH codes.
- Any additional information needed to reanalyze the data reported in this study may be requested from the lead contact.

METHOD DETAILS

This paper uses the methodology from two previous studies,[11,16] but with the added treatments of GHS for backing up the electric grid and a new method of using CH for both baseload and peaking power. Three types of models are used: a spreadsheet model (Note S2), a 3-D global weather-climate-air pollution model (GATOR-GCMOM) (Note S3), and a grid model (LOADMATCH) (Notes S4–S7).

The spreadsheet model is used first to project 2018 business-*as*-usual (BAU) energy consumption in end-use sectors (also called total final consumption) from IEA,[28] to 2050 for each of seven fuel types (oil, natural gas, coal, electricity, heat for sale, solar and geothermal heat, and wood and waste heat) in each of six end-use energy sectors (residential, commercial, transportation, industrial, agriculture-forestry-fishing, and military-other), and for each of 145 countries (Note S2). The projections (Note S2) are by fuel type, energy sector, and region of the world. They assume moderate economic growth, policy changes by world region, population growth, energy growth, use of some renewable energy, and modest energy efficiency measures.

The spreadsheet model is then used to estimate the 2050 reduction in energy demand due to converting each fuel type in each end-use sector in each country to electricity, electrolytic hydrogen, or heat, and providing the electricity and heat with wind-water-solar (WWS) (Note S2). The reduction is calculated with the conversion factors by fuel type and sector given in Table S3. Such conversion factors assume the use of vehicles or equipment running primarily on electricity (Note S2). Overall, about 95% of the technologies needed for a transition are already commercial. Those not commercial include long-distance aircraft and ships, which can technically be powered by hydrogen fuel cells,[29] plus some industrial processes.

Third, the spreadsheet is used to estimate nameplate capacities of WWS electricity and heat generators that can meet the annual-average demand in each country (Note S2). Tables S4–S6 provide the 2018 demands from IEA,[28] 2050 BAU demands projected from 2018, and the estimated 2050 WWS demands converted from 2050 BAU demands, by energy sector and country. The WWS electricity-generating technologies treated include onshore and offshore wind turbines (Wind); tidal and wave devices, geothermal electric power plants, and hydroelectric power plants (Water); and rooftop/utility solar photovoltaics (PV) and CSP plants (Solar) (Table S2). WWS heat sources treated include solar thermal and geothermal heat generators. WWS electricity storage technologies include CH, PHS, CSP storage, BS, and GHS. WWS heat storage technologies include water tanks and underground storage in soil. WWS cold storage technologies include water tanks and ice. Hydrogen is also stored for non-grid purposes. WWS electricity is transported via alternating current (AC), high-voltage AC (HVAC), and/or high-voltage direct current (HVDC) transmission lines and AC distribution lines. Whereas transmission costs and losses are accounted for, this study assumes perfect transmission within each region simulated. Building heating and cooling can be either through units in each building or district heating/cooling. WWS machines and appliances include battery-electric vehicles, hydrogen fuel cell-electric vehicles for long-distance transport; electric heat pumps (for individual building air and water heating and air conditioning, clothes drying, district heating/cooling, and low-temperature industrial heating); induction cooktops; arc, induction, and resistance furnaces for medium- and high-temperature industrial heat; lawn mowers; and leaf blowers, for example (Table S2).

GATOR-GCMOM (Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model) is a global air pollution-weather-climate model (Note S3). It is used to predict, at 30-s resolution from 2050 to 2052, onshore and offshore wind electricity supply, rooftop solar PV electricity supply, utility solar PV electricity supply, CSP electricity supply, solar heat supply, building cooling demand, and building heating demand in each of 145 countries (Table S1). Time-dependent wave electricity supply is estimated proportionately to time-dependent offshore wind supply. To perform these calculations, GATOR-GCMOM uses 2050 nameplate capacities from the spreadsheet model for each energy generator in each country (Note S3). It calculates building cooling and heating demands by comparing modeled ambient air temperature each 30-s time step in each climate model near-surface grid cell within each country with an assumed comfort temperature for buildings while accounting for building characteristics[30] (Note S3). GATOR-GCMOM also accounts for competition among wind turbines for available kinetic energy and changes in air temperature due to wind turbines, PV panels, CSP plants, and solar heat devices. GATOR-GCMOM output is used as LOADMATCH input.

LOADMATCH (Notes S4–S7) simulates the matching of electricity, heat, cold, and hydrogen demand with supply and storage over time. LOADMATCH is a time-dependent trial-and-error simulation model. It works by running multiple simulations for each region, one at a time. Each simulation advances forward one timestep at a time, just as the real world does, for any number of years. The main constraints are that electricity, heat, cold, and hydrogen demands plus losses, adjusted by demand response, must each meet corresponding WWS supplies and storage every 30-s timestep of a simulation. The simulation stops if a demand is not met during a timestep. Inputs (either the nameplate capacity of one or more generators; the peak charge rate, peak discharge rate, or peak energy capacity of a storage device; or characteristics of demand response) are then adjusted one at a time after examining what caused the demand mismatch (hence the description "trial-and-error" model). Another simulation is then run from the beginning. New simulations (usually less than 10) are run until demand is met during each time step of the entire simulation. After demand is met once, another 4–20 simulations are generally performed with further-adjusted inputs based on user intuition and experience to generate a set of solutions that match demand during every timestep. From the set, the lowest-cost solution is then selected. Because LOADMATCH does not permit load loss at any time, it is designed to exceed the utility industry standard of load loss once every 10 years.

LOADMATCH is not an optimization model, so it does not find the lowest-cost solution. However, it produces a set of low-cost solutions from which the lowest cost can be determined. Its advantage over an optimization model is that it can treat many more processes while taking orders of magnitude less computer time. It is able to solve multi-year simulations with a 30-s time step in just minutes (Note S4).

Table S2 summarizes the processes in LOADMATCH. Note S4 describes many of the model's inputs. Note S5 describes the new treatment of hydropower in the model, including how hydropower's total nameplate capacity, energy storage capacity, and annual recharge are allocated between baseload and peaking power uses. The answer involves solving a set of six equations and six unknowns constrained by the fact that hydropower's total nameplate capacity, reservoir energy capacity, and recharge rate in each country are limited to ~2020 values, thus known. Hydropower's output and peaking use during a time step is also limited by the smallest among three factors: the actual energy currently available in storage for baseload or peaking use, the hydropower maximum discharge rate (nameplate capacity) for peaking or baseload use, multiplied by the time step, and (in the case of peaking) the energy needed during the time step to keep the grid stable. In addition, energy in the peaking and baseload portions of all reservoirs in a region cannot exceed the maximum storage capacity for peaking or baseload energy, respectively. Any excess is drained from the reservoir without producing power.

Table S15 provides the resulting maximum charge rates, discharge rates, and energy capacities for each baseload, peaking, and total hydropower for each region. Figure S1 shows how these variables vary as a function of baseload energy storage time. The total hydropower storage capacity in all hydropower reservoirs among the 145 countries examined is ~1,470 TWh, which is approximately the worldwide storage capacity estimated by IEA.[31] For comparison, the total battery storage capacity among all 145 countries in the base case (Case I) is 68.91 TWh (Table S15). Thus, the storage capacity of hydropower already existing in the world is 21.3 times the storage capacity of batteries needed for 100% WWS across all 145 countries in 2050. However, batteries in 2050 in Case I also require a peak discharge rate of 17.2 TW, which compares with 1.16 TW in 2020 and 2050 for CH. Thus, BS is used mostly for peaking, whereas CH is used mostly for energy storage in this study.

Note S6 discusses the treatments of time-dependent demand profiles, maximum storage sizes, and flexible and inflexible demand in LOADMATCH. Note S7 describes the model's order of operation, including how it treats excess generation over demand and excess demand over generation. Note S7 also provides details of how LOADMATCH treats demand response. Updates to LOADMATCH for this study are described in the section, "simulations: four cases compared." Once LOADMATCH simulations are complete, energy costs, health costs, climate costs, and employment numbers between WWS and BAU (Notes S8 and S10) and new land requirements of WWS generators (Note S9) are estimated.

iScience, Volume *27*

Supplemental information

Batteries or hydrogen or both for grid electricity storage upon full electrification of 145 countries with wind-water-solar?

Mark Z. Jacobson

Supplemental Text, Tables, and Figures

Batteries or Hydrogen or Both for Grid Electricity Storage Upon Full Electrification of 145 Countries With Wind-Water-Solar?

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This supplementary information file contains additional discussion of the models used plus additional results, tables, and figures related to this study.

Supporting Text

Note S1. Summary

This study examines whether using green hydrogen (H_2) storage (GHS) together with or instead of battery storage (BS) helps to lower the cost of matching power demand (load) with supply on electricity grids throughout the world. 2050 grids are examined after all energy sectors have been electrified and the electricity has being provided with 100% wind-water-solar (WWS) generators. Such generators emit zero air pollutants and zero carbon. Green hydrogen is hydrogen produced with an electrolyzer using WWS electricity. In this study, non-grid hydrogen is defined as hydrogen produced and stored for non-grid purposes, namely steel and ammonia manufacturing and long-distance transport. Grid hydrogen is defined as hydrogen produced and stored to help keep the electric power grid stable.

Four scenarios are examined: Case I, a baseline case in which no hydrogen is allowed for grid electricity but hydrogen is used for non-grid purposes (steel and ammonia manufacturing and long-distance transport); Case II, a sensitivity case in which hydrogen is used for both grid and non-grid purposes, but hydrogen rectifiers, electrolyzers, compressors, and storage tanks are shared for both purposes and fuel cells consume the communally-stored hydrogen to produce grid electricity; Case III, a sensitivity case that is the same as Case II, except that unique rectifiers, electrolyzers, compressors, and storage tanks are used for grid versus non-grid hydrogen; and Case IV, a sensitivity case that is the same as Case II, except no grid battery storage is allowed.

This study expands on ref. [S1], which examined the effect of using green hydrogen for steel and ammonia production and long-distance transport on matching power demand with supply, storage, and demand response on the electric and heat grids in 24 world regions encompassing 145 countries. That study extended ref. [S2], which examined the ability of the same countries to avoid blackouts upon a transition of energy in all energy sectors to 100% WWS and storage with no use of hydrogen in industry but some use of hydrogen for long-distance transport.

Table S1 lists the 24 regions and the 145 countries within those regions treated in this and those two previous studies. The regions include nine large multi-country regions (Africa, Central America, Central Asia, China region, Europe, India region, the Middle East, South America, and Southeast Asia) and 15 individual countries or pairs of countries (Australia, Canada, Cuba, Haiti-Dominican Republic, Israel, Iceland, Jamaica, Japan, Mauritius, New Zealand, the Philippines, Russia-Georgia, South Korea, Taiwan, and the United States).

This SI describes the model in more detail and summarizes the results in multiple tables and figures.

Note S2. Methodology

This note summarizes the overall methodology used in this study then describes the first, step, which is to use a spreadsheet model to develop year-2050 roadmaps to transition each of 145 countries to 100% WWS among all energy sectors in order to meet annual-average demand.

The main steps in performing the overall analysis are as follows:

(1) project business-as-usual (BAU) end-use energy demand from 2018 to 2050 for each of seven fuel types in each of six energy-use sectors, for each of 145 countries;
(2) estimate the 2050 reduction in demand due to electrifying or providing direct heat for each fuel type in each energy sector in each country and providing that electricity and heat with WWS;
(3) during step (2), replace BAU steel and ammonia manufacturing with green-H_2 steel and ammonia manufacturing and replace BAU long-distance transport vehicles with green-hydrogen fuel cell-electric vehicles;
(4) perform resource analyses then estimate mixes of wind-water-solar (WWS) electricity and heat generators required to meet the aggregate demand in each country in the annual average;
(5) use a prognostic global weather-climate-air pollution model (GATOR-GCMOM), which accounts for competition among wind turbines for available kinetic energy, to estimate wind and solar radiation fields and building heat and cold demands every 30 s for three years in each region;
(6) group the 145 countries into 24 world regions and use a model (LOADMATCH) to match variable electricity, heat, cold, and hydrogen demand with variable supply, storage (electricity, heat, cold, and hydrogen storage), and demand response (DR) in each region every 30 s, from 2050 to 2052;

(7) evaluate energy, health, and climate costs of WWS vs BAU;
(8) calculate land area requirements of WWS; and
(9) calculate changes in WWS versus BAU jobs numbers.
(10) Perform three sensitivity simulations - one in which a portion of grid electricity battery storage is replaced with hydrogen production, storage, and discharge through fuel cells to electricity, but grid and non-grid hydrogen production and storage are carried out with the same equipment; a second that is the same as the first, but grid and non-grid hydrogen production and storage are each carried out with separate sets of equipment; and a third that is the same as the first, except no batteries are permitted.

Thus, three types of models are used for this study: a spreadsheet model (Steps 1-4), a 3-D global weather-climate-air pollution model (Step 5), and a model that matches electricity, heat, cold, and hydrogen demand with supply, storage, and demand response assuming perfect grid interconnection (Steps 6-10). The rest of this note describes the spreadsheet model which is available [S3]. Note S3 describes GATOR-GCMOM. Notes S4-S7 describe LOADMATCH.

We start with 2018 business-as-usual (BAU) end-use energy consumption (also called total final consumption) data for each country from the International Energy Agency (IEA) [S4]. End-use energy is energy directly used by a consumer. It is the energy embodied in electricity, natural gas, gasoline, diesel, kerosene, and jet fuel that people use directly, including to extract and transport fuels themselves. It equals primary energy minus the energy lost in converting primary energy to end-use energy, including the energy lost during transmission and distribution. Primary energy is the energy naturally embodied in chemical bonds in raw fuels, such as coal, oil, natural gas, biomass, uranium, or renewable (e.g., hydroelectric, solar, wind) electricity, before the fuel has been subjected to any conversion process.

For each country, the data include end-use energy in each of seven energy categories (oil, natural gas, coal, electricity, heat for sale, solar and geothermal heat, and wood and waste heat) in each of six energy sectors (residential, commercial, transportation, industrial, agriculture-forestry-fishing, and military-other).

These data are projected for each fuel type in each sector in each country from 2018 to 2040 using “BAU reference scenario” projections from the U.S. Energy Information Agency (EIA) [S5] for each of 16 world regions. This is extended to 2075 using a ten-year moving linear extrapolation. The reference scenario is one of moderate economic growth and accounts for policies, population growth, economic and energy growth, the growth of some renewable energy, modest energy efficiency measures, and reduced energy use. EIA refers to their reference scenario as their BAU scenario. The 2050 BAU end-use energy for each fuel type in each energy sector in each of 145 countries is then set equal to the corresponding 2018 end-use energy from [S4] multiplied by the EIA 2050-to-2018 energy consumption ratio, available after the extrapolation, for each fuel type, energy sector, and region containing the country.

The 2050 BAU end-use energy for each fuel type in each sector and country is then converted to 2050 WWS electricity and heat using the conversion factors in Table S3.

For example, air and water heat from fossil fuel burning, wood burning, and waste heat are converted to heat from air- and ground-source heat pumps running on WWS electricity. Building cooling is also provided by heat pumps powered by WWS electricity. Existing solar and geothermal direct heat are retained without change. Natural gas dryers and stoves are converted to heat pump dryers and electric induction stoves, respectively. As such, there is no need for any energy carrier, aside from electricity, in a building. Buildings also use more efficient appliances, LED lights, and better insulation.

Liquid fuel (mostly gasoline, diesel, bunker fuel, and jet fuel) and natural gas vehicles are transitioned to battery-electric (BE) vehicles and some hydrogen fuel cell-electric (HFC) vehicles, where the hydrogen is produced with WWS electricity (green hydrogen). BE vehicles are assumed to dominate short- and long-distance light-duty ground transportation, construction machines, agricultural equipment, short- and moderate-distance (<1,000 km) heavy-duty trucks, trains (except when powered by electric rails or overhead wires), ferries, speedboats, and ships. Batteries will also power short-haul (<3 h) aircraft flights. HFC vehicles make up all long-distance ships, trains, and trucks; medium- and long-distance aircraft; and long-distance military vehicles [S6]. Gasoline lawnmowers, leaf blowers, and chainsaws are converted to electric equivalents.

High- and medium-temperature industrial processes are electrified with electric arc furnaces, induction furnaces, resistance furnaces, dielectric heaters, and electron beam heaters. Low-temperature heat for industry is provided with electric heat pumps and concentrated solar power (CSP) steam. Green hydrogen for steel and ammonia manufacturing replaces BAU fuels for these processes, as described in [S1]. Table S7 summaries the annual hydrogen production by year for these processes, as well as for long-distance transport. All electricity for industry comes from WWS sources.

In each country, a mix of WWS resources is estimated in the spreadsheet to meet the all-sector annual-average end-use energy demand. The mix is determined after a WWS resource analysis is performed for each country and after the technical potential of each WWS resource in each country is estimated. Ref. [S7] provides the methodology for the resource analysis performed here for each country. Table S7 of ref. [S2] shows solar rooftop PV potentials by country.

Next, a first estimate of the nameplate capacities of a mix of WWS generators needed to meet annual-average all-purpose end-use energy demand in each country is calculated iteratively in the spreadsheet [S3]. The penetration of each WWS electricity generator in each country is limited by the following constraints: (1) each generator type cannot produce more electricity in the country than the technical potential allows; (2) the land area taken up among all WWS land-based generators should be no more than a few percent of the land area of the country of interest; (3) the area of installed rooftop PV in each country must be less than the respective rooftop area suitable for PV; (4) the total nameplate capacity is the same as in 2020; and (6) wind and solar, which are complementary in nature, are used in roughly equal proportions where feasible.

Country-specific nameplate capacities from the spreadsheet model are then used as inputs into the global weather-climate-air-pollution model, GATOR-GCMOM (Note S3), as described next.

Note S3. Description of GATOR-GCMOM and its Calculations

This note briefly summarizes the GATOR-GCMOM model and the main processes that it treats. GATOR-GCMOM is a three-dimension Gas, Aerosol, Transport, Radiation, General Circulation, Mesoscale, and Ocean Model [S8][S9][S10][S11][S12][S13]. It simulates weather, climate, and air pollution on the global through urban scales. The main processes treated are as follows:

Gas processes (emissions, gas photochemistry, gas transport, gas-to-particle conversion, gas-cloud interactions, and removal).

Aerosol processes (size- and composition-resolved emissions, homogeneous nucleation, coagulation, condensation, dissolution, equilibrium and non-equilibrium chemistry, aerosol-cloud interactions, and aerosol removal).

Cloud processes (size- and composition-resolved aerosol particle activation into cloud drops, drop freezing; collision-coalescence with cloud particles and aerosol particles, condensation/evaporation, dissolution, ice crystal formation, graupel formation, lightning formation, convection, precipitation, and drop breakup).

Transport processes (horizontal and vertical advective and diffusive transport of individual gas, size- and composition-resolved aerosol particles, and size- and composition-resolved hydrometeor particles).

Radiative processes (spectral solar and thermal infrared radiation transfer; heating rates that affect temperatures; actinic fluxes that affect photolysis coefficients; radiation transfer through gases, aerosols, clouds, snow, sea ice, and ocean water).

Meteorological processes (winds, temperatures, pressures, humidity, size- and composition-resolved clouds).

Surface processes (dry deposition of gases, sedimentation of aerosol and hydrometeor particles, dissolution of gases and particles into the oceans and surface water, soil moisture and energy balance, evapotranspiration, sea ice and snow formation and impacts; radiative transfer through snow, sea ice, and ocean water).

Ocean processes (2-D ocean transport and 3-D ocean diffusion and chemistry, phytoplankton affecting optical properties and emissions, radiative transfer through the ocean).

GATOR-GCMOM simulates feedback among all these processes, in particular among meteorology, solar and thermal-infrared radiation, gases, aerosol particles, cloud particles, oceans, sea ice, snow, soil, and vegetation. Model predictions have been compared with data in 34 peer-reviewed studies. The model has also taken part in 14 model inter-comparisons [S14].

The model is run here at 4- by 5-degree horizontal resolution and with 68 sigma-pressure-coordinate layers in the vertical, from the ground to 0.219 hPa (~60 km), with 15 layers in the bottom 0.95 km. Of these, the bottom five layers above the ground are at 30-m resolution; the next seven are at 50-m resolution, one is at 100-m resolution, and the last two are at 200-m resolution. Vertical resolution from 1 to 21 km is 500 m.

Country-specific inputs into GATOR-GCMOM from the spreadsheet model include the nameplate capacities of onshore and offshore wind turbines, rooftop and utility PV panels, CSP plants, and solar thermal heat plants needed to meet annual-average demand in 2050.

Onshore wind turbines are placed in windy areas in each country in GATOR-GCMOM. Offshore turbines are placed in coastal water in each country that has a coastline. The wind turbine blades in the model cross five vertical model layers. Spatially-varying model-predicted wind speeds are used to calculate wind power output from each turbine every 30 s. This calculation accounts for the reduction in the wind's kinetic energy and speed due to the competition among wind turbines for limited available kinetic energy [S11].

Rooftop solar PV panels, utility PV panels, CSP plants, and solar thermal plants are also placed by country in GATOR-GCMOM. Rooftop PV is placed in urban areas. Utility PV, CSP, and solar thermal are placed in southern parts of each country in the Northern Hemisphere and northern parts of each country in the Southern Hemisphere.

The model calculates the temperature-dependence of PV output [S13] and the reduction in sunlight to buildings and the ground due to the conversion of radiation to electricity by solar devices [S13][S14]. It also accounts for (1) changes in air and ground temperature due to power extraction by solar and wind devices and subsequent electricity use [S13][S14]; (2) impacts of time-dependent gas, aerosol, and cloud concentrations on solar radiation and wind fields [S10]; (3) radiation to rooftop PV panels at a fixed optimal tilt [S13]; and (4) radiation to utility PV panels, half of which are at an optimal tilt and the other half of which track the sun with single-axis horizontal tracking [S13].

Finally, GATOR-GCMOM calculates building heat and cold demands in each country every 30 s during 2050-2052. The model predicts the ambient air temperature in each of multiple surface grid cells in each country and compares it with an ideal building interior temperature, set to 294.261 K (70ºF). It then calculates how much heating or cooling energy is needed every 30 s to maintain the interior temperature among all buildings in the grid cell (assuming an average *U*-value and surface area for buildings and a given number of buildings in each grid cell). Ref. [S15] provides full details. The time series demands among all grid cells in a country are then summed to obtain a countrywide demand time series for the country, which is then output for use in LOADMATCH.

Note S4. Description of and Processes in the LOADMATCH Model

This note discusses the LOADMATCH model [S1][S2][S15][S16][S17][S18][S19] and its main processes. LOADMATCH is a trial-and-error simulation model written in Fortran. Its goal is to match time-dependent electricity, heat, cold, and hydrogen demand with supply, storage, and demand response without failure. It works by running multiple simulations for each grid region, one at a time. Each simulation marches forward one timestep at a time, just as the real world does, for any number of years for which sufficient input data are available. In past studies, the model was run for 1 to 6 years, but there is no technical or computational limit preventing the model from running for hundreds or thousands of years, given sufficient input data. In the present study, the time step used is 30 s and the simulation period is three years for each region.

The main constraints are that electricity, heat, cold, and hydrogen demands plus losses, adjusted by demand response, must each meet corresponding WWS supplies and storage every 30-s timestep of a simulation. If a demand is not met during any timestep, the simulation stops. Inputs (either the nameplate capacity of one or more generators; the peak charge rate, peak discharge rate, or peak capacity of storage; or characteristics of demand response) are then adjusted one at a time based on an examination of what caused the demand mismatch (thus, LOADMATCH is a "trial-and-error" model). Another simulation is then run from the beginning. New simulations are run until demand is met every time step of the simulation period. After demand is met once, additional simulations are performed with further-adjusted inputs based on user intuition and experience to generate a set of solutions that match demand every timestep. The lowest-cost solution in this set is then selected.

Unlike with an optimization model, which solves among all timesteps simultaneously, a trial-and-error model does not know what the weather will be during the next timestep. Because a trial-and-error model is non-iterative, it requires less than a minute for a 3-year simulation that uses a 30-s timestep. This is 1/500th to 1/100,000th the computer time of an optimization model for the same number of timesteps, regardless of computer architecture. The disadvantage of a trial-and-error model compared with an optimization model is that the former does not determine the least cost solution out of all possible solutions. Instead, it produces a set of viable solutions, from which the lowest-cost solution is selected.

Table S2 summarizes many of the processes treated in LOADMATCH. Model inputs are as follows:

(1) time-dependent electricity from onshore and offshore wind turbines, residential and commercial rooftop PV systems, utility PV plants, CSP plants, and wave devices in each region of interest, predicted by GATOR-GCMOM;
(2) time-dependent heat from solar thermal devices, predicted by GATOR-GCMOM;
(3) time-dependent building heat and cold demands, predicted by GATOR-GCMOM;
(4) baseload (constant) tidal electricity and geothermal electricity and heat supply, with magnitudes determined in the spreadsheet model;

(5) baseload and peaking conventional hydropower (CH) electricity production (Note S5) constrained by 2020 annual hydropower output and nameplate capacity;
(6) specifications of hot-water and chilled-water sensible-heat thermal energy storage (HW-STES and CW-STES) (peak charge rate, peak discharge rate, peak storage capacity, losses into storage, and losses out of storage);
(7) specifications of underground thermal energy storage (UTES);
(8) specifications of ice storage (ICE);
(9) specifications of electricity storage in pumped hydropower storage (PHS), phase-change materials (PCM) coupled with CSP (CSP-PCM), batteries (BS), and green hydrogen (GHS) used in fuel cells (this study);
(10) specifications of hydrogen electrolyzer, rectifier, compressor, and storage tank sizes for non-grid versus grid applications, and the quantity of hydrogen needed for steel and ammonia manufacturing, long-distance transport, and grid electricity backup (this study);
(11) specifications of electric heat pumps needed for district heating and cooling;
(12) specifications of district heating and individual building electric heat pump coefficient of performance;
(13) specifications of a demand response system;
(14) specifications of losses along short- and long-distance transmission and distribution lines;
(15) assumed or data-derived time-dependent electricity, heat, cold, and hydrogen demands; and
(16) specifications of scheduled and unscheduled maintenance downtimes for generators, storage, and transmission.

From model results, differences in energy, health, and climate costs and job creation and loss between BAU and WWS are estimated. Land requirements of WWS are also calculated. The cost calculation requires specifications of WWS electricity and heat generator costs; electricity, heat, cold, and hydrogen storage costs; hydrogen electrolyzer, rectifier, compressor, dispenser, cooling, and fuel cell costs; transmission and distribution costs; air pollution costs; and climate costs. Changes in job numbers require specifications of job data for generators, storage, hydrogen, and transmission/distribution. Land requirements require specification of the installed power density of different types of land-based generators.

LOADMATCH is used here to match time-dependent (30-s resolution) electricity and heat demand and losses with supply, storage, and demand response during 2050-2052. Note 5 details the updated treatment of hydropower in the model. Note S6 discusses thermal and electrical demand profiles, flexible and inflexible demands, and the treatment of demand response in the model. Note 7 discusses the order of operation in the model. Notes S6-S7 describe demand response. Whereas GATOR-GCMOM provides time-dependent wind, solar, and wave electricity supplies and solar heat supplies for LOADMATCH, geothermal electricity and heat supplies and tidal electricity supplies are assumed to be baseload and constant throughout the year. Hydropower is used for both baseload and peaking electricity (Note S5).

Transmission in LOADMATCH is assumed to be perfectly interconnected. However, transmission and distribution costs and losses are accounted for (Table S25). The regions simulated here (Table S1) cover different spatial scales, from 11 relatively small regions (Cuba, Haiti-Dominican Republic, Iceland, Israel, Jamaica, Japan, Mauritius, New Zealand, Philippines, South Korea, and Taiwan) to the continental scale. Long-distance transmission costs increase when countries are interconnected versus isolated. For the smallest individual counties or pairs of countries (Cuba, Haiti-Dominican Republic, Iceland, Israel, Jamaica, Mauritius, South Korea, and Taiwan), no long-distance transmission is assumed because the distance across such entities is less than a typical HVDC transmission line length (1,000-2,000 km). For New Zealand, 15% of all non-rooftop PV and non-curtailed electricity consumed is assumed to be subject to long-distance transmission. For Central America, Japan, and the Philippines, 20% is assumed to be subject to long-distance transmission. For all other countries and regions, 30% is assumed to be subject to long-distance transmission (Table S16). Ref. [S18] evaluated the difference in cost when countries in several grid regions in Europe were isolated versus interconnected. The study found that interconnecting reduces aggregate annual energy costs, but whether isolated or interconnected, all countries can match all energy demand with supply and storage at low cost.

Note S5. Treatment of Hydropower for Both Baseload and Peaking

This study expands the use of hydropower to treat it for both baseload and peaking purposes. In all previous studies with LOADMATCH, hydropower was used for peaking only.

As with all previous studies with LOADMATCH, the annual hydropower output (TWh/y) in 2050 in each country is limited to the near-present-day output (year-2020 output in this case) in the country. The 2020 annual hydropower energy output is assumed to be exactly replenished each year by rainfall and runoff.

As in most previous studies with LOADMATCH [S1][S2][S15][S17][S18][S19], the 2050 peak discharge rate (nameplate capacity) of hydropower in each country is limited to the country's 2020 nameplate capacity. The nameplate capacity of hydropower is the peak discharge rate of its generators.

Hydropower reservoirs contain water for both energy and non-energy purposes. About 50-60% of the water in a reservoir with hydropower generators attached to it is used for energy [S20]. The hydropower storage capacity available for energy in all reservoirs worldwide is estimated to be ~1,470 TWh, broken down as follows: North America: 370 TWh; China: 250 TWh; Latin America: 245 TWh; Europe: 215 TWh; Eurasia: 130 TWh; Africa: 125 TWh; Asia Pacific: 120 TWh; Middle East: 15 TWh (Figure 4.8 of ref. [S20]). The maximum hydropower storage capacity (TWh) in each country here is estimated by multiplying these regional storage capacities by the ratio of the 2020 hydroelectric energy output of the country to that of the ref. [S20] region the country falls in. The maximum storage capacity (S_t) in each of the 24 regions in this study (Table S1) is then calculated simply by summing the maximum storage capacities among all countries in the region. Table S15 provides the result for each region.

The maximum storage capacity, total nameplate capacity, and recharge rate of hydropower in each region are then distributed between baseload and peaking power uses by solving a set of six equations and six unknowns.

First, the sum of the maximum energy storage capacities (TWh) for baseload power (S_b) and peaking power (S_p) in each region must equal the overall maximum energy storage capacity among all hydropower reservoirs in the region:

$$S_b + S_p = S_t \tag{S1}$$

S_t is known and calculated as described above. Second, the sum of the instantaneous average charge rates (TW) of baseload power (C_b) and of peaking power (C_p) in all reservoirs in a region equals the total average charge rate (C_t) in the region:

$$C_b + C_p = C_t \tag{S2}$$

Since enough rainfall and runoff occur to replenish the water released during hydroelectricity production during the year, C_t equals the 2020 total hydroelectricity production (TWh/y) in the region divided by 8,760 hours per year, thus is known.

Third, the sum of the maximum discharge rates (nameplate capacities) (TW) of generators assigned to baseload power (N_b) and peaking power (N_p) in a region equals the total nameplate capacity (N_t) of all generators among all hydropower plants in the region:

$$N_b + N_p = N_t \tag{S3}$$

N_t is the 2020 total nameplate capacity in each region, thus is also known. Fourth, the maximum discharge rate (TW) of baseload power (N_b) in each region must equal the instantaneous average charge rate of baseload power (C_b) in the region:

$$N_b = C_b \tag{S4}$$

Since the maximum discharge rate of baseload power is matched by an equal instantaneous average charge rate, there should, in theory, be no need for baseload storage. However, in reality, discharged water for baseload power is not replenished immediately. As such, sufficient storage capacity is assigned to baseload hydropower so that, if the baseload portion of all reservoirs in a region is full, it can supply H_b hours straight of hydroelectricity at peak discharge rate N_b without any replenishment. Thus, the fifth equation is

$$N_b H_b = S_b \tag{S5}$$

where H_b is the number of hours of storage in the baseload portion of each reservoir at the maximum discharge rate, N_b.

Finally, the portion of the reservoir storing energy for peaking requires H_p hours to refill when empty when the recharge rate is C_p. Thus, the maximum energy storage capacity (TWh) for peaking (S_p) is

$$C_p \times H_p = S_p \qquad \text{(S6)}$$

In sum, six equations (S1-S6) are solved for six unknowns (S_b, S_p, C_b, C_p, N_b, N_p) given known values for the other variables (S_t, C_t, N_t, H_b, and H_p). The exact solution is

$$S_b = (C_t H_p - S_t)/(H_p/H_b - 1) \qquad \text{(S7)}$$

$$N_b = C_b = S_b / H_b \qquad \text{(S8)}$$

$$N_p = N_t - N_b \qquad \text{(S10)}$$

$$C_p = C_t - C_b \qquad \text{(S11)}$$

$$S_p = S_t - S_b \qquad \text{(S12)}$$

The solution to Equation S7 requires $H_p \geq S_t/C_t$ and $0<H_b \leq S_t/C_t$. The parameter S_t/C_t is the actual number of hours required to refill reservoirs, at rate C_t, from zero to their total energy capacity S_t. Since S_t is derived from ref. [S20] data and C_t, which is the annual average power added to reservoirs, equals the data-derived annual average power discharged from conventional hydroelectric dams in 2020, S_t/C_t is a known parameter in each region. For the 24 regions considered here, the value of S_t/C_t ranges from 679.03 h in the Mideast to 8,670.21 h in Africa, with an average value among all 145 countries of 2,606.38 h (derived from Table S15). The average value of S_t/C_t among all 145 countries suggests that reservoirs worldwide are replenished, on average, 3.36 times per year.

When $H_p=S_t/C_t$, then $S_b=0$ (Equation S7), and all storage in the reservoir is used for peaking. If $H_p< S_t/C_t$, then $S_b<0$, which is not a physical solution. As H_p increases, then more storage capacity goes to baseload power for a given value of H_b. Here it is assumed that H_p=8,760 h (365 d). The value implies that storage for peaking is refilled only once per year in each region, which is a slower rate than the actual refill rate in all regions of the world. The slower refill rate of storage capacity for peaking implies a faster refill rate of storage capacity for baseload power. This is necessary since baseload power is continuously flowing.

From Equation S7, as H_b approaches 0, S_b approaches 0, and all storage capacity is used for peaking. As H_b approaches S_t/C_t, S_b approaches S_t, and all storage goes toward baseload (Figure S1). H_b cannot exceed S_t/C_t. If $H_b>S_t/C_t$, then more water will go into the baseload energy portion of the reservoir than is available in the total (baseload plus peaking) energy portion of the reservoir.

For most regions H_b is set here equal to 1,440 h (60 d), thereby allowing a good portion of the nameplate capacity of each region to be stored in reserve for baseload and a good portion to be used as needed for peaking. For Iceland and South America, H_b=120 h (5 d) and 360 h (15 d), respectively. These values allows both regions to use most hydro storage capacity for peaking and less for baseload (Figure S1 and Table S15). For Africa, which has a very high value of S_t/C_t, H_b is set to 8,640 h (360 d), which allows most hydro storage capacity to be used for baseload (Figure S1 and Table S15). For the Mideast and Israel, which have very low values of S_t, H_b cannot be higher than S_t/C_t = 679 hours (28.3 days), which results in all storage capacity being used for baseload and none for peaking (Figure S1 and Table S15).

Table S15 gives the solution to Equations S7-S12 for each region for the values of H_p and H_b as specified above. Figure S1 shows the variation of the solution with H_b for several countries.

In sum, whereas baseload power is produced and discharged continuously in the model every 30 s, peaking power is also produced every 30 s but discharged only when needed due to a lack of other WWS resources available. Whereas Table S15 gives hydropower's maximum energy storage capacity available for each baseload and storage, hydropower's output for baseload use or peaking use during a time step is also limited by the smallest among three factors: the actual energy currently available in storage for baseload or peaking use, the hydropower maximum discharge rate (nameplate capacity) for peaking or baseload use, multiplied by the time step, and (in the case of peaking) the energy needed during the time step to keep the grid stable. In addition, energy in the peaking portion of reservoirs in a region cannot exceed S_p. Any excess is drained from the reservoir without producing power. Energy in the baseload portion of reservoirs in a region always equals S_b since baseload energy is continuously released and re-filled.

Note S6. Time-Dependent Thermal/Electricity Demand Profiles in LOADMATCH

This note discusses the development of time-dependent demand profiles at 30-s time resolution for use in LOADMATCH. Demand profiles are developed starting with 2050 annual-average WWS energy demand values for each sector in each country from Tables S4-S6. These demands are separated into (1) electricity and direct heat demands for low-temperature heating; (2) electric demands for cooling and refrigeration; (3) electricity demands for producing, compressing, and storing hydrogen to run hydrogen fuel cell-electric vehicles with or to manufacture steel and ammonia with; and (4) all other electricity demands (including industrial high-temperature heat demands), as described in Section S1.3.3 of ref. [S14] and updated in ref. [S15]. Each of these demands is then divided further into flexible and inflexible demands. Flexible demands include electricity and direct heat demands that can be used to fill cold and low-temperature heat storage (district heat storage or building water tank storage), electricity demands used to produce and compress hydrogen (since all hydrogen can be stored), and remaining electricity and direct heat demands subject to demand-response management. Inflexible demands are all demands that are not flexible. Table S16 gives the fraction of building heating and cooling demands subject to district heating and cooling in each region.

Demands subject to demand response can be shifted forward in time one time step at a time, but by no more than eight hours, until the demands are met. Demands subject to heat/cold storage can be met with such storage or with electricity, either currently available or stored. Inflexible demands must be met immediately with electricity that is currently available or stored.

To summarize, total annual-average cooling and low-temperature heating demands consist of flexible demands subject to storage, flexible demands subject to demand response, and inflexible demands. Such annual-average cooling and low-temperature heating demands for each country are converted to time-dependent cooling and low-temperature heating demands using the time-dependent cooling and low-temperature heating demand output from GATOR-GCMOM for each country (Note S3). In LOADMATCH, the cooling and low-temperature heating demand time series from GATOR-GCMOM are summed for each time step over all countries in each region to obtain regional time series. The annual average of each regional time series is then found. Each regional time series, from 2050 to 2052, is then scaled by the ratio of the annual-average cooling or low-temperature heating demand subject to storage required for a 100% WWS region in 2050 from Table S9 to the annual-average cooling or heating demand from the GATOR-GCMOM time series, just calculated. This gives time-dependent 2050-2052 cooling and heating demands for each region that, when averaged over time, exactly match the estimated 2050 annual-average demands from Table S9.

Annual-average 2050-2052 inflexible electric demands (in the residential, commercial, transportation, industrial, agriculture-forestry-fishing, and military-other sectors) in each region are converted to time-dependent 2050-2052 inflexible electric demands for the region by projecting contemporary time-dependent electric demand data for the region forward to 2050-2052. Contemporary hourly demand data for European countries are for 2014 [S21] Those for almost all remaining countries are for 2030 [S22]. Since demand profiles for Sudan, Zimbabwe, and Equatorial Guinea do not exist from either of these datasets, their profiles are assumed to be the same as those of a nearby country, but with the magnitude each hour scaled so that the annual-average inflexible demand reflects those of each original country.

The 2050-2052 inflexible demand time-series for each country is then obtained by multiplying the 2014 or 2030 time-series electric demand, respectively, for the country by the ratio of the annual-average 2050 inflexible demand for the region the country resides in (Table S9) to the annual-average 2014 or 2030 inflexible demand profile summed among all countries in the region.

Finally, all remaining demands (all non-heating, non-cooling flexible demands), which include most electric demands for transportation (for electric and hydrogen fuel cell vehicles), for high-temperature industrial heat, and for steel and ammonia manufacturing with hydrogen, are distributed evenly during the year.

For transportation, this assumption is roughly justified by the fact that, between 2016-2019 in the U.S., the minimum and maximum monthly U.S. gasoline supplies were 7.76% and 8.73%, respectively, of the annual supply [S23], with the highest consumption during the summer and the lowest during the winter. Both gasoline vehicle (GV) and battery-electric vehicle (BEV) ranges drop with lower temperature, with BEV ranges dropping more. For example, gasoline-vehicle fuel mileage is about 15-24% lower at 20ºF (-6.67ºC) than at 77ºF (25ºC) [S24], whereas BEV range is ~40% lower between those two temperatures [S25]. Since gasoline consumption is greater during summer than winter, this implies that the summer minus winter difference in BEV electricity consumption will be less than the summer minus winter difference in gasoline consumption, justifying a relatively even spread during the year of electricity consumption with BEVs.

Eighty-five percent of electricity demands for vehicles and 70% of electricity demands for high-temperature industrial heat are assumed to be flexible demands subject to demand response or storage. As such, these demands can be shifted forward in time if necessary or pulled from storage whenever electricity storage is sufficient available. The demand for producing and compressing hydrogen for fuel cell vehicles comprises 33.7% of the total transportation demand among the 145 countries [Table S7, Column (f) divided by Table S8, Column (f)]. The demand for producing and compressing hydrogen for steel and ammonia manufacturing comprises 12.6% of the total industrial demand [Table S7, Column (e) divided by Table S8, Column (e)]. The demand for producing and compressing hydrogen for both transportation and industry comprises 12.1% of the all-purpose demand [Table S7, Column (g) divided by Table S8, Column (a)]. All these demands are flexible, so hydrogen can be produced whenever excess electricity is available. The hydrogen can then be stored and used as needed. Since 100% of electric demands for hydrogen production and compression for vehicles (33.7% of transportation electric demands) are flexible and 85% of all transportation demands are flexible, 77.4% of all electric demands for battery-electric vehicles (66.3% of transportation electric demands) are flexible.

Once time-dependent demand profiles are developed, maximum electricity, heat, and cold storage sizes and times are estimated (Tables S15, S17).

Note S7. Order of Operation in LOADMATCH

In this note, the order of operations in LOADMATCH, including how the model treats excess generation over demand and excess demand over generation, is summarized. The first situation discussed is one in which the current (instantaneous) supply of WWS electricity or heat exceeds the current electricity or heat demand. The total demand, whether for electricity or heat, consists of flexible and inflexible demands. Whereas flexible demand may be shifted forward in time with demand response, inflexible demand must be met immediately. If WWS instantaneous electricity or heat supply exceeds the instantaneous inflexible electricity or heat demand, then the supply is used to satisfy that demand. The excess WWS is then used to satisfy as much current flexible electric or heat demand as possible. If any excess electricity exists after inflexible and current flexible demands are met, the excess electricity is used to fill electricity storage or to produce heat, cold, or hydrogen, which is either stored or used immediately.

Electricity storage is filled first. Excess CSP high-temperature heat is put in CSP thermal energy storage. If CSP storage is full, remaining high-temperature heat is used to produce electricity that is then used, along with excess electricity from other sources, to charge battery storage. If battery storage is full or not included, remaining electricity is first used (in Cases II-IV) to produce hydrogen that can later be used to re-generate electricity in a fuel cell. If either hydrogen storage is filled or the electric power available exceeds electrolyzer plus compressor nameplate capacities for grid hydrogen (Case III) or grid plus non-grid hydrogen (Cases II and IV), the remaining electricity is used to fill pumped hydropower storage, cold water storage, ice storage, hot water tank storage, and underground thermal energy storage, respectively. Remaining excess electricity after that is used to produce hydrogen used only for non-grid purposes (Cases I and III only, since hydrogen produced for non-grid purposes in Cases II and IV is produced with the same electrolyzers as for grid purposes). Any residual after that is curtailed. Hydropower dam storage is filled naturally with rainfall and runoff as described in Note S5.

Heat and cold storage are filled by using excess electricity to power an air-, water-, or ground-source heat pump to move heat or cold from the air, water, or ground, respectively, to a thermal storage medium. Non-grid and grid hydrogen storage is filled by using electricity in an electrolyzer (after a rectifier converts AC to DC electricity for use in the rectifier) to produce hydrogen and in a compressor to compress the hydrogen, which is then moved to a storage tank.

If any excess direct geothermal or solar heat exists after it is used to satisfy inflexible and flexible heat demands, the remainder is used to fill either district heat storage (water tank and underground heat storage) or building water tank heat storage.

The second situation is one in which current demand exceeds WWS electricity or heat supply. When current inflexible plus flexible electricity demand exceeds the current WWS electricity supply from the grid, the first step is to use electricity storage [CSP, battery, hydrogen through fuel cells (Cases II-IV), pumped hydro, and hydropower storage used for peaking, in that order] to fill in the gap in supply. The electricity is used to supply the inflexible demand first, followed by the flexible demand.

If electricity storage becomes depleted and flexible demand persists, demand response is used to shift the flexible demand to a future time step.

If the inflexible plus flexible heat demand subject to storage exceeds immediate WWS heat supply, then centralized stored heat (in district heating water tanks and underground storage) is used to satisfy district heat demands subject to storage, and distributed heat storage (in hot water tanks) is used to satisfy individual building water heat demands. If stored heat becomes exhausted, then any remaining low-temperature air or water heat demand becomes either an inflexible demand (85%), which must be met immediately with electricity, or a flexible demand (15%), which can either be met with electricity or shifted forward to the next time step with demand response, up to a maximum number of eight hours. After that, the demand becomes inflexible.

Similarly, if the inflexible plus flexible cold demand subject to storage exceeds cold storage (in ice or water), excess cold demand becomes either an inflexible demand (85%), which must be met immediately with electricity, or a flexible demand (15%), which can be met with electricity or shifted forward in time with demand response. If a demand shifted forward is not met after eight hours, it is turned into an inflexible demand

Finally, if the current non-grid hydrogen demand depletes non-grid hydrogen storage, the remaining non-grid hydrogen demand becomes an inflexible electrical demand that must be met immediately with current electricity.

In any of the cases above, if electricity is not available to meet the remaining inflexible demand, the simulation stops and must be restarted after increasing nameplate capacities of generation and/or storage.

Because the model does not permit load loss at any time, it is designed to exceed the utility industry standard of load loss once every 10 years.

Note S8. Energy, Air Pollution, and Climate Costs

Once LOADMATCH simulations are complete, the resulting energy costs, health costs, and climate costs between WWS and BAU are estimated. All costs are evaluated with a social discount rate of 2 (1-3)% [S14] since the analysis here is a social cost analysis. Social cost analyses are from the perspective of society, not of an individual or firm in the market. Thus, social cost analyses must use a social discount rate, even for the private-market-cost portion of the total social cost.

BAU air pollution health cost estimates (Tables S36 and S37) are based on the projected number of all air pollution deaths per year in 2050 by country (Table S38) multiplied by the fraction of such deaths that are due to energy-related emissions (0.9) ([S14], a 2050 value of statistical life (VOSL) for each country, a cost factor for morbidity (1.15), and a cost factor for non-health and non-climate environmental impacts (1.1) [S14]. Results are shown in ref. [S3] for each country. The mean VOSL in 2050 among all countries is $5.58 million/person (USD 2020). The mean total cost of each life after accounting for associated morbidities and non-health environmental impacts is $7.05 million/person.

Energy-related air pollution deaths due to WWS are assumed to equal zero since 100% WWS results in zero emissions associated with energy, even during the mining and manufacturing of WWS equipment.

BAU climate costs are estimated based on the mean social cost of carbon in each country and region (Table S38) multiplied by the estimated anthropogenic CO_2-equivalent emissions in 2050 (Table S38). The mean social cost of carbon in 2050 in each country is calculated as $558 ($315-$1,188)/tonne-$CO_2$e [S3] and is an update to USD 2020 from values in ref. [S14]. The 2050 estimate assumes 2010 values of $250 ($125-$600)/tonne-$CO_2$e and growth factors of 1.5 (1.8-1.2)% per year between 2010 and 2050 and a multiplier of 1.226 to obtain values in USD 2020. The 2010 SCC is estimated as follows. Ref. [S26] suggests that the 2014 lower bound of the SCC should be at least $125 per tonne-$CO_2$e. Ref. [S27] concludes that incorporating the effect of climate change on the rate of economic growth can increase the SCC to between $200 and $1,000 per tonne-$CO_2$e. Ref. [S28] similarly finds that accounting for the long-term effects of temperature rise on economic productivity results in climate change damage estimates that are 2.5 to 100 times higher than those from earlier studies. Nevertheless, we limit the upper limit of the 2010 SCC to \$600/tonne-CO_2e.

Note S9. Land Requirements

Footprint is the physical area on the top surface of soil or water needed for each energy device [S29]. It does not include the area of underground structures. Spacing is the area between some devices, such as wind turbines, wave devices, and tidal turbines, needed to minimize interference of the wake of one turbine with downwind turbines. Spacing area can be used for multiple purposes, including rangeland, ranching land, industrial land (e.g., installing solar PV panels), open space, or open water. Table S39 provides estimated footprint and spacing areas per megawatt of nameplate capacity of WWS electricity and heat generating technologies considered here.

Applying the footprint and spacing areas per megawatt nameplate capacity from Table S39 to the new nameplate capacities needed to provide grid stability (obtained by subtracting the existing nameplate capacities in Table S10 from the existing plus new nameplate capacities in Table S11) gives the total new land footprint and spacing areas required for each country and region, as shown in Table S40.

New land footprint arises only for solar PV plants, CSP plants, onshore wind turbines, geothermal plants, and solar thermal plants. Offshore wind, wave, and tidal generators are in water, so they don't take up new land, and rooftop PV does not take up new land. The footprint area of a wind turbine is relatively trivial (primarily the area of the tower and of exposed cement above the ground surface).

Note S10. Employment Changes

A final metric discussed relevant to policy decision-making is net job creation and loss. Table S41 provides estimated numbers of long-term full-time construction and operation jobs per megawatt of new nameplate capacity or per kilometer of new transmission line for several electricity-generating and storage technologies and for transmission and distribution expansion. The total number of jobs produced in a region equals the new nameplate capacity of each electricity generator or storage device or the number of kilometers of new transmission/distribution lines multiplied by the respective number of jobs per MW from the table.

The number of jobs per MW was derived for the United States primarily from the Jobs and Economic Development Impact (JEDI) models [S30]. These models estimate the number of construction and operation jobs plus earnings due to building an electric power generator or transmission line. The models treat direct jobs, indirect jobs, and induced jobs.

Direct jobs are jobs for project development, onsite construction, onsite operation, and onsite maintenance of the electricity generating facility. Indirect jobs are revenue and supply chain jobs. They include jobs associated with construction material and component suppliers; analysts and attorneys who assess project feasibility and negotiate agreements; banks financing the project; all equipment manufacturers; and manufacturers of blades and replacement parts. The number of indirect manufacturing jobs is included in the number of construction jobs. Induced jobs result from the reinvestment and spending of earnings from direct and indirect jobs. They include jobs resulting from increased business at local restaurants, hotels, and retail stores, and for childcare providers, for example. Changes in jobs due to changes in energy prices are not included. Energy price changes may trigger changes in factor allocations among capital, energy input, and labor that result in changes in the number of jobs.

Specific output from the JEDI models for each new electric power generator includes temporary construction jobs, permanent operation jobs, and earnings, all per unit nameplate capacity. A temporary construction job is defined as a full-time equivalent job required for building infrastructure for one year. A full-time equivalent (FTE) job is a job that provides 2,080 hours per year of work. Permanent operation jobs are full-time jobs that last as long as the energy facility lasts and that are needed to manage, operate, and maintain an energy generation facility. In a 100% WWS system, permanent jobs are effectively indefinite because, once a plant is decommissioned, another one must be built to replace it. The new plant requires additional construction and operation jobs.

The number of temporary construction jobs is converted to a number of permanent construction jobs as follows. One permanent construction job is defined as the number of consecutive one-year construction jobs for L years to replace $1/L$ of the total nameplate capacity of an energy device every year, all divided by L years, where L is the average facility life. In other words, suppose 40 GW of nameplate capacity of an energy technology must be installed over 40 years, which is also the lifetime of the technology. Also, suppose the installation of 1 MW creates 40 one-year construction jobs (direct, indirect, and induced jobs). In that case, 1 GW of wind is installed each year and 40,000 one-year construction jobs are required each year. Thus, over 40 years, 1.6 million one-year jobs are required. This is equivalent to 40,000 40-year jobs. After the technology life of 40 years, 40,000 more 1-year jobs are needed continuously each year in the future. As such, the 40,000 construction jobs are permanent jobs.

Jobs losses due to a transition to WWS include losses in the mining, transport, processing, and use of fossil fuels, biofuels, bioenergy, and uranium. Jobs will also be lost in the BAU electricity generation industry and in the manufacturing of appliances that use combustion fuels. In addition, when comparing the number of jobs in a BAU versus WWS system, jobs are lost due to *not* constructing BAU electricity generation plants, petroleum refineries, and oil and gas pipelines.

Note S11. Summary of Energy, Storage, Cost, Land, and Employment Results

S11.1. Energy Demand and Generation Results

Tables S4-S6 provide the 2018 annual-average end-use BAU demand, the projected 2050 annual-average end-use BAU demand, and the 2050 annual-average end-use WWS demand by energy sector and country from this study. These values are the same for all four cases (I-IV) here and the same as in ref. [S1].

Tables S4-S6 indicate that transitioning from BAU to 100% WWS in 2050 in 145 countries reduces the 2050 annual-average end-use power demand by an average of 55.9%. Of this, 38.0 percentage points are due to the efficiency of using WWS electricity over combustion;

11.3 percentage points are due to eliminating energy in the mining, transporting, and refining of fossil fuels; and 6.6 percentage points are due to end-use energy efficiency improvements and reduced energy use beyond those with BAU (Tables S4-S6). Of the 38.0% reduction due to the efficiency advantage of WWS electricity, 20.3 percentage points are due to the efficiency advantage of WWS transportation, 4.2 percentage points are due to the efficiency advantage of using WWS electricity for industrial heat, and 13.5 percentage points are due to the efficiency advantage of using heat pumps instead of combustion heaters. Whereas all-purpose energy demand declines by 55.9%, the energy is almost all electricity (with some direct heat), causing world-average electricity consumption to increase by 87% compared with BAU (Tables S4-S6).

Table S7 summarizes the hydrogen production needed for steel production, ammonia production, and for long-distance transport (all non-grid hydrogen applications) by country and region. It also provides the energy needed to produce the hydrogen for each application. Table S8 summarizes the 2050 annual-average end-use WWS demand by sector for each of the 24 regions. Table S9 provides a breakdown of the 2050 annual-average end-use demand by inflexible versus flexible demand. Flexible demand is divided into cold demand subject to storage, low-temperature heat demand subject to storage, demand for non-grid hydrogen, and all other flexible demands, which are subject to demand response. It also summarizes the non-grid hydrogen needed by region. Values in Tables S7-S10 are the same for all four cases (Cases I-IV) here.

Table S10 provides the existing 2020 nameplate capacities of each electricity and heat generator by country. These values are the same for all four cases here. Table S11 provides the final nameplate capacities for each generator in each region. These values are the same for Cases I-III but different for Case IV, as shown in the table. The reason is that in Case IV, batteries are all replaced by GHS for grid electricity storage. Due to the lower round-trip efficiency of GHS than BS, more WWS generators are sometimes needed in Case IV than in Cases I-III.

Table S12 gives the ratio of the final nameplate capacities needed to meet continuous demand in LOADMATCH to the initial estimated nameplate capacities needed to meet annual-average demand, as determined from the spreadsheet analysis used to estimate such demands [S3]. The ratios are referred to as capacity adjustment factors (CAFs). The value, shown are the same for Cases I-III but differ for Case IV for onshore and offshore wind, utility PV, and CSP. Only ~13% more overall generator nameplate capacity is needed, summed over all 145 countries, to meet continuous 2050 demand in Cases I-III than to meet annually-averaged 2050 demand (42.060 TW from summing the "All regions" row of Table S11 for Cases I-III vs. 37.202 TW from estimates of nameplate generators to meet annual-average demand in ref. [S3]). The difference is due to oversizing generation in order to meet continuous demand. Storage is also needed to meet continuous demand (Tables S15 and S17).

Table S13 gives the regional-average modeled capacity factor (CF) of each generator over each three-year simulation in the base case (Case I). Values in each region in Cases II-IV are the same as in Case I, except for slight differences in the CF of hydropower since hydropower's use varies during each simulation since it provides both electricity generation and storage. In addition, in Case IV, the all-region weighted average for each generator differs for onshore and offshore wind, utility PV, and CSP, relative to Cases I-III, because of the different nameplate capacities of generators used in Case IV versus Cases I-III.

Table S14 gives the percent of electricity plus heat produced (to meet demand and losses) from each WWS energy generator, averaged over the three-year simulations in the base case (Case I) for each region. Results for Cases II-III are similar but slightly different because the change in hydropower output in each simulation slightly shifts the percentages of other generators. Results for Case IV differ more due to the additional generator nameplate capacities in that case.

S11.2. Storage Results

Table S15 provides storage maximum charge rates, discharge rates and capacities. The total battery storage capacity among all 145 countries in the base case (Case I) is 68.91 TWh (Table S15). For comparison, the total hydropower storage capacity in reservoirs in the 145 countries is ~1,470 TWh, the same as the worldwide storage capacity estimated by IEA [S20]. Thus, the storage capacity of hydropower already existing in the world is 21.3 times the storage capacity of batteries needed for 100% WWS across all 145 countries in 2050. However, batteries in 2050 have a peak discharge rate of 17.2 TW, whereas hydropower has a peak discharge rate of 1.16 TW, all of which already exists. Thus, batteries in this study are used more for peaking, whereas hydropower is used more for energy storage.

World hydropower output in 2020 was 4,370 TWh/y [S31], which indicates that hydropower cycled 2.97 its storage times per year in 2020 (4,370 TWh/y output divided by 1,470 TWh of storage). In the present study, the 145-country output was 4,940 TWh/y, thus hydropower cycled 3.36 times per year. By contrast, the number of battery cycles needed per year in the Case I simulations varied from 0 to 236, with 15 regions needing 66 cycles or less per year [Column (e) of Table S17]. Table S18 provides the battery storage capacities and maximum charge and discharge rates for all four cases (Cases I-IV).

Although batteries store electricity here for only four hours at their peak discharge rate, longer storage can be obtained by concatenating batteries in series. In other words, if 8-h storage is needed, then two 4-h batteries can be depleted sequentially. Having a low number of hours of storage (e.g., four hours) maximizes the flexibility of batteries both to meet peaks in power demand (GW) and to store electrical energy for long periods (GWh). For example, suppose 100 batteries, each with 4-h storage and a peak discharge rate of 10 kW, are concatenated. This allows for either 400 hours of storage at a peak discharge rate of 10 kW or 4 h of storage at a peak discharge rate of 1,000 kW, or anything in between.

Thus, batteries with longer than 4-h storage are not necessary for keeping the grid stable. However, storage times of greater than four hours and up to 58.1 h, while not needed, can be advantageous for a region. Batteries with storage times longer than ~58.1 h were never needed nor advantageous in Case I [Table S17, Column (k)]. The ratio of the maximum storage capacity (TWh) to the maximum battery discharge rate (TW) that actually occurs during each simulation (R_{ideal}) ranges from four hours to 58.1 h. This ratio is the maximum number of hours of storage ever needed at the maximum discharge rate that actually occurred during a simulation. If this ratio exceeds four hours (the number of hours of storage at the peak discharge rate assumed for all simulations), then the battery peak discharge rate assumed is greater than that needed, so the peak discharge rate assumed can be decreased, without any impact on the results, if the number of hours of storage at that peak discharge rate is proportionately increased in order to maintain constant storage capacity. Table S17, Columns (l) and (m) shows that including GHS reduces the ratio of the maximum storage capacity to the maximum discharge rate of batteries to no more than 28.9 h. In the case of Taiwan, for example, the ratio decreases from 58.1 to 8.8 h. Thus, using GHS together with BS reduces the need to use batteries for storage capacity while maintaining their use for peaking.

S11.3. Cost Results

The net present value of the capital cost to transition all 145 countries in the base case (Case I) while keeping the grid stable is \$62.3 trillion (USD 2020), with new electricity and heat generators comprising \$47.01 trillion of this (Table S35). The remaining costs are for electricity, heat, cold, and hydrogen storage; hydrogen electrolysis and compression; heat pumps for district heating; and long-distance transmission. The capital cost does not include the capital costs of new electric appliances and machines (e.g., heat pumps for buildings, electric vehicles, industrial equipment) since it is assumed that their fossil-fuel counterparts will be replaced in any case within 15 years at similar cost. The overall capital cost increases to \$62.7 trillion in Case II and to \$68.1 trillion in Case IV but declines slightly to \$62.2 trillion in Case III (Table S35). Tables S33-S35 provide a dissection of the levelized cost of energy (LCOE) for each region for all four cases (Cases I-IV).

Among all 145 countries, the 2050 annual social cost for BAU energy, without a conversion to WWS, is \$83.2 trillion/y, which consists of a 2050 private energy cost (\$17.8 trillion/y), health cost (\$33.6 trillion/y), and climate cost (\$31.8 trillion/y) (Table S36). To determine BAU energy costs across all sectors, we assume that the BAU cost per unit-all-energy equals the BAU cost per unit-electricity. This assumption is needed since BAU costs in non-electricity sectors are not readily available whereas those in the electricity sector are. Because annual WWS social (and private) costs are an order of magnitude lower than are corresponding BAU costs, this assumption should make no difference in the conclusions drawn here.

Thus, switching all countries to 100% WWS in the base case (Case I) reduces both social and private energy costs to \$6.895 trillion/y, or by 91.7% and 61.3%, respectively (Table S36). The significant decrease in private energy cost between BAU and WWS occurs because WWS reduces energy demand by 55.9% (Table S36) and the cost per unit energy by ~12.2% The decrease in social energy cost occurs because WWS eliminates health and climate costs in addition to reducing energy needs and cost. Table S37 shows the percent decrease in private and social costs of energy due to WWS in Cases II-IV.

The WWS capital cost divided by the difference between the BAU and WWS annual private and social energy costs is the payback time due to the WWS private and social cost savings, respectively. The 145-country payback time due to annual private energy cost savings is a mean of 5.7 years in the base case (Case I). That due to social cost savings is 0.82 years. The capital cost is paid back through energy sales rather than subsidies.

Among all world regions in the base case (Case I), the average WWS LCOE, between 2020 and 2050, that results in a stable grid, is 8.78 ¢/kWh (Table S35). This cost is dominated by the costs of electricity generation (3.90 ¢/kWh), electricity distribution (2.38 ¢/kWh), short-distance transmission (1.05 ¢/kWh), non-grid hydrogen production/compression/storage (0.61 ¢/kWh), battery storage (0.45 ¢/kWh), , long-distance transmission (0.17 ¢/kWh), geothermal plus solar heat generation (0.078 ¢/kWh), heat pumps for district heating (0.058 ¢/kWh), underground heat storage (0.056 ¢/kWh), CSP and pumped hydro storage (0.021 ¢/kWh), and hot water storage (0.008 ¢/kWh) (Table S35). In Cases II-IV, battery costs drop relative to Case I due to the decreased capacity of batteries needed in Cases II-IV, but either non-grid H_2 (Cases II, IV) or grid H_2 (Cases II-IV) costs rise relative to Case I. The overall (all-region) LCOE increases in Cases II-IV relative to Case I (Table S35).

S11.4. New Land Area Requirements

The total new land area for footprint (before removing the fossil fuel infrastructure) required with 100% WWS in the base case (Case I) is about 0.16% of the 145-country land area (Table S40), almost all for utility PV and CSP. WWS has no footprint associated with mining fuels to run the equipment, but both WWS and BAU energy infrastructures require one-time mining for raw materials for new plus repaired equipment construction.

The only spacing area over land needed in a 100% WWS world is between onshore wind turbines. Table S40 indicates that the spacing area for onshore wind to power the 145 countries in Case I is about 0.39% of the 145-country land area.

Together, the new land footprint plus spacing areas for 100% WWS across all energy sectors in Case I represents 0.55% of the 145-country land area, and most of this land area is multi-purpose spacing land. Since the nameplate capacities of electricity and heat generating technologies in Cases II and III are the same as in Case I, the land requirements in Cases II and III are the same as in Case I. However, since the nameplate capacities of onshore wind and utility PV increase in many regions in Case IV relative to Cases I-III, the new land required in Case IV is 15% greater than in Cases I-III (Table S40).

S11.5. Employment Change Results

Table S42 estimates the number of permanent, full-time jobs created and lost due to a transition in each country to 100% WWS by 2050. The job creation accounts for new direct, indirect, and induced jobs in the electricity, heat, cold, and hydrogen generation, storage, and transmission (including HVDC transmission) industries (Note S10). 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 job losses in Table S42 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.

Table S42 indicates that transitioning to 100% WWS may produce 52.5 million new long-term, full-time jobs. Also, 27.2 million jobs may be lost, for a net increase of 25.3 million long-term, full-time jobs produced among the 145 countries in the base Case. Net job gains occur in 21 out of 24 regions, although not all countries within each region with job gains. Only the regions of Africa, Canada, and Russia experience net job losses. Locations with fewer net job gains or net job losses are usually locations with a substantial fossil fuel industry. However, some countries with high fossil fuel employment (e.g., Saudi Arabia) have net job gains because of the large buildout of WWS infrastructure per capita in those countries. More jobs, not accounted for here, may arise from the need to build more electrical appliances and to improve building energy efficiency.

In Cases II-IV, 23.6 million, 23.6 million, and 26.3 million more long-term, full-time jobs were produced than lost, respectively, among the 145 countries (Table S42). Thus, net employment decreases in Cases II and III relative to Case I. The reason is that substantially fewer batteries were needed in Cases II and III than in Case I. The drop in employment due to fewer batteries was greater than the increase in employment due to adding more hydrogen infrastructure. Employment increased in Case IV relative to Case I because of the additional wind and solar PV generators needed in Case IV.

S11.6. Energy Conservation and Grid Stability

LOADMATCH exactly conserves energy over the three-year simulations for every region and for every case. For example, in Case I, "End-use demand plus losses" for "All regions" in Table S22 equals 11,747 GW averaged over the simulations, and this exactly equals "Supply plus changes in storage." Of that total, 8,970 GW is "annual-average end-use demand," which is the exact total, within roundoff error, shown in Tables S4-S6 for "All Countries." The rest of the total is the sum of transmission and distribution losses, losses going in and out of storage, and curtailment losses.

Supporting Tables

Table S1. Countries and Regions Treated in LOADMATCH, Related to Star Methods.
The 24 world regions comprised of 145 countries treated in this study.

Region	Country(ies) Within Each Region
Africa	Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of the Congo, Côte d'Ivoire, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, Tanzania, Togo, Tunisia, Zambia, Zimbabwe
Australia	Australia
Canada	Canada
Central America	Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua, Panama
Central Asia	Kazakhstan, Kyrgyz Republic, Pakistan, Tajikistan, Turkmenistan, Uzbekistan
China region	China, Hong Kong, Democratic People's Republic of Korea, Mongolia
Cuba	Cuba
Europe	Albania, Austria, Belarus, Belgium, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Gibraltar, Greece, Hungary, Ireland, Italy, Kosovo, Latvia, Lithuania, Luxembourg, Macedonia, Malta, Moldova Republic, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, United Kingdom
Haiti region	Dominican Republic, Haiti
Iceland	Iceland
India region	Bangladesh, India, Nepal, Sri Lanka
Israel	Israel
Jamaica	Jamaica
Japan	Japan
Mauritius	Mauritius
Mideast	Armenia, Azerbaijan, Bahrain, Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic, Turkiye, United Arab Emirates, Yemen
New Zealand	New Zealand
Philippines	Philippines
Russia region	Georgia, Russia
South America	Argentina, Bolivia, Brazil, Chile, Colombia, Curacao, Ecuador, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Venezuela
Southeast Asia	Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Singapore, Thailand, Vietnam
South Korea	Korea, Republic of
Taiwan	Taiwan
United States	United States

Table S2. Processes Treated in LOADMATCH, Related to Star Methods.
Several processes treated within, inputs into, and outputs from the LOADMATCH model for matching demand with supply, storage, and demand response.

WWS electricity and heat generation
Onshore and offshore wind electricity Utility photovoltaic (PV) electricity Residential, commercial/government rooftop PV electricity Concentrated solar power (CSP) electricity Geothermal electricity Tidal and wave electricity Solar and geothermal heat
WWS storage for grid electricity
Existing hydropower reservoirs with water turbines (no uprating turbines) Hydropower used separately for peaking and baseload Pumped hydropower storage with water turbines CSP storage with steam turbines Batteries Green hydrogen storage and fuel cells*
WWS heat and cold storage
Heat storage in water tanks and soil Cold storage in water tanks and soil
WWS hydrogen production, storage, and use
Green hydrogen production by electrolysis using WWS electricity Hydrogen compression Hydrogen storage Separate or combined electrolysis, compression, and storage for grid versus non-grid hydrogen* Hydrogen for steel and ammonia manufacturing in industry Hydrogen fuel cell-electric long-distance aircraft, ships, trains, trucks, military vehicles Hydrogen for grid electricity*
WWS machines and appliances
Battery-electricity vehicles for all but long-distance (where hydrogen fuel cell vehicles used) Battery-electric construction machines and agricultural equipment Electric heat pumps for building cooling and air/water heating Electric heat pumps for district heating and cooling Electric heat pumps for low-temperature industrial heat Electric heat pump dryers Electric induction cooktops, lawn mowers, leaf blowers Electric arc and resistance furnaces for mid- and high-temperature industrial heat
WWS electricity and heat grids
Assumes perfect transmission interconnections AC, HVAC, and HVDC transmission line lengths calculated Transmission and distribution line losses calculated District heating/cooling and distributed heating/cooling treated Losses of electricity and heat in and out of storage calculated Losses of electricity and heat due to curtailment and generator downtime calculated
Costs, jobs, and land use
Costs of all generation, all storage, short- and long-distance transmission/distribution Costs of hydrogen rectifiers, electrolyzers, compressors, storage, dispensing, cooling, fuel cells Avoided cost of air pollution damage Avoided cost of climate damage Changes in job numbers for new generators, storage, transmission Land footprint and spacing requirements for new electricity and heat generators
GATOR-GCMOM output used in LOADMATCH
Onshore and offshore wind, roof PV, utility PV, CSP, solar heat, wave supply Heat and cold demands in buildings Wind supply accounts for array losses due to competition among turbines for kinetic energy Wind and solar supplies account for air temperature changes due to wind and solar devices

*Process added as part of this study.

Table S3. Fuel-to-Electricity Conversion Factors, Related to Star Methods.

Factors to multiply BAU end-use energy consumption by in each of six energy sectors to obtain equivalent WWS end-use energy consumption. The factors are the ratio of BAU work-output/energy-input to WWS work-output/energy-input, by fuel and sector. Values are the same for all four cases (Cases I-IV).

	Residential		Comm./Govt.		Industrial		Transportation		Ag-for-fish		Military-other	
Fuel	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency	Elec: fuel ratio	Extra effic-iency
Oil	0.2[a]	0.84	0.2[a]	0.95	0.78[e]	0.98	.21/.40[f]	0.96	0.21	0.96	0.21	0.96
Natural gas	0.2[a]	0.81	0.2[a]	1	0.78[e]	0.98	.21/.40[g]	0.88	0.2	0.91	0.2	0.91
Coal	0.2[a]	1	0.2[a]	1	0.78[e]	0.97	--	--	0.2	--	0.2	--
Electricity	1[b]	0.77	1[b]	0.78	1[b]	0.92	1[b]	1	1	0.78	1	0.78
Heat for sale	0.25[c]	1.0	0.25[c]	1	0.25[c]	1	--	--	0.25	1	0.25	1
WWS heat	1[d]	1	1[d]	1	1[d]	1	--	--	1	1	1	1
Biofuels/waste	0.2[a]	0.87	0.2[a]	1	0.78[e]	1	0.21/[h]	0.96	0.2	0.93	0.2	0.93

Residential demands include electricity and heat consumed by households, excluding transportation.

Comm./Govt. demands include electricity and heat consumed by commercial and public buildings, excluding transportation.

Industrial demands include energy consumed by all industries, including iron, steel, and cement; chemicals and petrochemicals; non-ferrous metals; non-metallic minerals; transport equipment; machinery; mining (excluding fuels, which are treated under transport); food and tobacco; paper, pulp, and print; wood and wood products; construction; and textile and leather.

Transportation demands include energy consumed during any type of transport by road, rail, domestic and international aviation and navigation, or by pipeline, and by agricultural and industrial use of highways. For pipelines, the energy required is for the support and operation of the pipelines. The transportation category excludes fuel used for agricultural machines, fuel for fishing vessels, and fuel delivered to international ships, since those are included under the agriculture/forestry/fishing category.

Agriculture-forestry-fishing demands include energy consumed by users classified as agriculture, hunting, forestry, or fishing. For agriculture and forestry, it includes consumption of energy for traction (excluding agricultural highway use), electricity, or heating in those industries. For fishing, it includes energy for inland, coastal, and deep-sea fishing, including fuels delivered to ships of all flags that have refueled in the country (including international fishing) and energy used by the fishing industry.

Military-other demands include fuel used by the military for all mobile consumption (ships, aircraft, tanks, on-road, and non-road transport) and stationary consumption (forward operating bases, home bases), regardless of whether the fuel is used by the country or another country.

Elec:fuel ratio (electricity-to-fuel ratio) is the ratio of the energy input of end-use WWS electricity to energy input of BAU fuel needed for the same work output. For example, a value of 0.5 means that the WWS device consumed half the end-use energy as did the BAU device to perform the same work.

Extra efficiency is the effect of the additional efficiency and energy reduction measures in the WWS system beyond those in the BAU system. It assumes moderate economic growth. For example, in the case of natural gas, oil, and biofuels for residential air and water heating, it is the additional efficiency due to better insulation of pipes and weatherizing homes. For residential electricity, it is due to more efficient light bulbs and appliances. In the industrial sector, it is due to faster implementation of more energy efficient technologies than in the BAU case. The improvements are calculated as the product of (a) the ratio of energy use, by fuel and energy sector, of the EIA [S5] *high efficiency all scenarios* (HEAS) case and their *reference* (BAU) case and (b) additional estimates of slight efficiency improvements beyond those in the HEAS case [S14].

Oil includes end-use energy embodied in oil products, including refinery gas, ethane, liquefied petroleum gas, motor gasoline (excluding biofuels), aviation gasoline, gasoline-type jet fuel, kerosene-type jet fuel, other kerosene, gas oil, diesel oil, fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin waxes, petroleum coke, and other oil products. Does not include oil used to generate electricity.

Natural gas includes end-use energy embodied in natural gas. Does not include natural gas used to generate electricity.

Coal includes end-use energy embodied in hard coal, brown coal, anthracite, coking coal, other bituminous coal, sub-bituminous coal, lignite, patent fuel, coke oven coke, gas coke, coal tar, brown coal briquettes, gas works gas, coke oven gas, blast furnace gas, other recovered gases, peat, and peat products. Does not include coal used to generate electricity.

Electricity includes end-use energy embodied in electricity produced by any source.

Heat for sale is end-use energy embodied in any heat produced for sale. This includes mostly waste heat from the combustion of fossil fuels, but it also includes some heat produced by electric heat pumps and boilers.

WWS heat is end-use energy in the heat produced from geothermal heat reservoirs and solar hot water heaters.

Biofuels and waste include end-use energy for heat and transportation from solid biomass, liquid biofuels, biogas, biogasoline, biodiesel, bio jet kerosene, charcoal, industrial waste, and municipal waste.

[a]The ratio 0.2 assumes electric heat pumps (mean coefficient of performance, COP, of 4, with a range of 3.2 to 5.2) replace oil, gas, coal, biofuel, and waste combustion heaters (COP=0.803) for low temperature air and water heating in buildings. The ratio is calculated by dividing the COP of BAU heaters by that of heat pumps. The mean heat pump COP of 4 assumes 60% of heat pumps are air-source at the low end of the range (COP=3.2) and 40% are ground source at the high end of the range (COP=5.2). The COP of combustion heaters assumes 98% have a COP of 0.8 and 2% have a COP of 0.95.

[b]Since *electricity* is already end-use energy, there is no reduction in end-use energy (only in primary energy) from using WWS technologies to produce electricity.

[c]Since *heat for sale* is low-temperature heat, it will be replaced by heat from electric heat pumps (mean COP=4) giving an electricity-to-fuel ratio of 0.25 (=1/4). Heat for sale is also low-temperature heat in the industrial sector, so it is replaced in that sector with heat pumps as well.

[d]Since *WWS heat* is already from WWS resources, there is no reduction in end-use or primary energy upon a transition to 100% WWS for this source.

[e]The ratio 0.78 for industrial heat processes assumes a mixture of electric resistance furnaces, arc furnaces, induction furnaces, and dielectric heaters replace oil, gas, coal, biofuels, and waste combustion heaters for medium and high-temperature heating processes (above 100^{o}C). It also assumes that heat pumps replace those fuels for low-temperature heating processes. The electricity-to-fuel ratio for high-temperature replacement is 0.88 (=0.854/0.97), where 0.854 is the mean COP for natural gas, coal, or oil boilers and 0.97 is that for electric resistance furnaces. The COP for fossil fuel boilers assumes 80% have a COP of 0.8 and 20% have a COP of 107%, which can occur because some industrial boilers recapture waste heat and latent heat of condensation, and the COP is based on the lower heating value. The electricity-to-fuel ratio for heat pumps replacing low-temperature industrial heat processes is 0.21 (=0.854/4), where 0.854 was just defined and 4 is the mean COP of a heat pump. It is assumed that 15% of industrial heat will be with heat pumps (electricity-to-fuel ratio of 0.21) and 85% with high-temperature replacements (0.88), giving a mean replacement ratio of 0.78. The industrial sector electricity-to-fuel ratio and extra efficiency measure factors are applied only after industrial sector BAU energy used for mining and processing fossil fuels, biofuels, bioenergy, and uranium (industry "own use") has been removed from each fuel sector. The amount of industry own use is given by IEA [S4] for each country. The ratio and factors are also applied only after the change in energy between BAU and WWS during steel manufacturing due to purifying iron using green hydrogen in a shaft furnace instead of purifying iron from coke in a blast furnace is accounted for (Table S7), and during ammonia manufacturing due to using green hydrogen instead of gray hydrogen is accounted for (Table S7).

[f]The electricity-to-fuel ratio for a battery-electric (BE) vehicle is 0.21; that for a hydrogen fuel cell (HFC) vehicle is 0.40. The ratio for BE vehicles is calculated assuming 85% of vehicles have a ratio of 0.19 and 15% have a ratio of 0.31. The 0.19 ratio is calculated as the ratio of the low tank-to-wheel efficiency of internal combustion engine (ICE) vehicles (0.17) to the high plug-to-wheel efficiency of a BE vehicle (0.89). The 0.31 value is calculated as the high efficiency of an ICE vehicle (0.2) divided by the low efficiency of a BE vehicle (0.64). The 0.40 ratio for HFC vehicles is calculated assuming 85% of vehicles have a ratio of 0.365 and 15% have a ratio of 0.578. The 0.365 value is the low tank-to-wheel efficiency of an ICE vehicle (0.17) divided by the high efficiency of an HFC vehicle (0.466). The 0.578 value is the high efficiency of an ICE vehicle (0.20) divided by the low efficiency of an HFC vehicle (0.346). 2% of BAU energy in the form of *oil* in the *transportation* sector is used to transport fossil fuels, biofuels, bioenergy, and uranium. That BAU energy is eliminated in a 100% WWS world. Of the remaining 2050 end-use fuel from oil used for transportation, a worldwide average of 75.3% is replaced with battery electricity, and 24.7% is replaced with electrolytic hydrogen (Table S7). The percent replaced by battery electricity is multiplied by the electricity-to-fuel ratio for BE vehicles to determine the WWS electricity used for BE transportation replacing oil and the percent replaced by electrolytic hydrogen is multiplied by the electricity-to-fuel ratio for HFC transportation replacing oil.

[g]About 80% of *natural gas* energy in the transportation sector is used to transport fossil fuels, biofuels, bioenergy, and uranium (e.g., through pipelines or other means). That BAU energy is eliminated in a 100% WWS world. Of the remainder, 95% is assumed to be electrified with BE vehicles and 5% is assumed to be electrified with HFC vehicles.

[h]It is assumed that 100% of *biofuels and waste* currently used in transportation will be electrified in 2050 thus will have the electricity-to-fuel ratio of a BE vehicle.

Table S4. 2018 BAU, 2050 BAU , and 2050 WWS Power Demand, Related to STAR Methods.
1st row of each country: 2018 total annual-average end-use demand (GW) and percentage of the total demand by sector. 2nd row: projected 2050 total annual-average end-use BAU demand (GW) and percentage of the total demand by sector. 3rd row: estimated 2050 total annual-average end-use demand (GW) and percentage of the total demand by sector if 100% of end-use delivered BAU demand in 2050 is instead provided by WWS. Column (k) shows the percentage reductions in total 2050 BAU demand due to switching from BAU to WWS, including the effects of (h) energy use reduction due to the higher work to energy ratio of electricity over combustion, (i) eliminating energy use for the upstream mining, transporting, and/or refining of coal, oil, gas, biofuels, bioenergy, and uranium, and (j) policy-driven increases in end-use efficiency beyond those in the BAU case. Column (l) is the ratio of electricity demand (=all energy demand) in the 2050 WWS case to the electricity demand in the 2050 BAU case. Whereas Column (l) shows that electricity consumption increases in the WWS versus BAU cases, Column (k) shows that all energy decreases. Values are the same for all four cases (Cases I-IV). This table shows results for countries alphabetically from A-G. Tables S5-S6 show results for the remaining countries.

Country	Scenario	(a) Total annual-average end-use demand (GW)	(b) Resi-den-tial % of total	(c) Co m-mer cial % of total	(d) Ind us-try % of total	(e) Tra ns-port % of total	(f) Ag-for-fish % of total	(g) Mil-itary-other % of total	(h) % change end-use dem-and with WWS due to higher work: energy ratio	(i) % change end-use demand with WWS due to elim-inating up-stream	(j) % change end-use demand with WWS due to effic-iency be-yond BAU	(k) Over-all % change in end-use demand with WWS	(l) WWS :BAU elec-tricity dem-and
Albania	BAU 2018	3.0	22.7	9.5	23.8	38.7	5.23	0.00					
	BAU 2050	4.4	27.0	11.7	20.5	36.9	3.97	0.00					
	WWS 2050	2.1	34.9	16.0	27.3	19.7	2.17	0.00	-39.6	-4.5	-9.0	-53.1	1.37
Algeria	BAU 2018	58.0	29.4	1.3	27.5	36.6	0.40	4.81					
	BAU 2050	142.6	21.7	1.1	21.3	51.6	0.34	4.02					
	WWS 2050	43.8	23.2	2.0	40.3	29.0	0.60	4.86	-43.6	-18.2	-7.5	-69.3	2.38
Angola	BAU 2018	14.3	54.2	5.1	13.1	27.5	0.06	0.05					
	BAU 2050	24.5	44.5	4.3	14.8	36.2	0.06	0.05					
	WWS 2050	7.9	41.6	2.6	27.3	28.5	0.04	0.03	-55.7	-4.2	-8.0	-67.9	2.47
Argentina	BAU 2018	83.5	22.4	7.4	33.1	31.6	5.53	0.00					
	BAU 2050	144.4	21.4	6.8	29.6	38.0	4.18	0.00					
	WWS 2050	51.1	21.3	11.6	45.3	19.3	2.54	0.00	-40.8	-16.5	-7.4	-64.6	1.96
Armenia	BAU 2018	3.0	31.6	3.0	16.0	34.6	1.42	13.44					
	BAU 2050	4.8	32.6	3.2	12.5	40.6	1.02	10.20					
	WWS 2050	1.5	37.1	5.1	28.6	13.4	1.57	14.18	-40.2	-18.4	-10.0	-68.6	1.39
Australia	BAU 2018	132.2	10.6	8.3	39.0	39.5	2.65	0.00					
	BAU 2050	208.8	10.4	11.8	41.2	34.5	2.15	0.00					
	WWS 2050	92.3	12.5	19.0	48.0	19.2	1.26	0.00	-34.6	-14.8	-6.4	-55.8	1.58
Austria	BAU 2018	37.7	22.3	8.3	33.2	34.3	1.87	0.00					
	BAU 2050	47.9	21.6	8.7	30.3	37.9	1.54	0.00					
	WWS 2050	20.9	18.2	11.4	45.0	24.2	1.11	0.00	-38.5	-11.2	-6.8	-56.4	1.70
Azerbaijan	BAU 2018	12.6	34.7	6.9	23.3	30.0	5.10	0.00					
	BAU 2050	19.1	37.4	9.3	21.5	28.0	3.84	0.00					
	WWS 2050	6.4	35.8	19.4	20.4	20.8	3.67	0.00	-46.7	-10.7	-9.4	-66.8	1.34
Bahrain	BAU 2018	9.4	11.5	7.4	54.4	26.6	0.07	0.00					
	BAU 2050	17.6	14.5	8.6	52.4	24.4	0.07	0.00					
	WWS 2050	9.6	19.7	12.3	58.1	9.8	0.10	0.00	-22.7	-15.7	-7.2	-45.5	1.36
Bangladesh	BAU 2018	42.8	48.2	2.1	30.9	14.6	3.72	0.42					
	BAU 2050	82.7	38.1	2.5	31.9	23.6	3.51	0.42					
	WWS 2050	35.8	26.6	3.8	58.0	9.0	1.85	0.75	-39.8	-8.1	-8.8	-56.7	1.96
Belarus	BAU 2018	25.8	26.7	10.9	34.5	22.0	5.92	0.00					
	BAU 2050	37.5	28.3	12.5	31.7	22.7	4.70	0.00					
	WWS 2050	12.8	25.1	17.7	37.9	15.5	3.82	0.00	-47.5	-12.7	-5.7	-65.8	1.86
Belgium	BAU 2018	63.5	16.8	9.6	30.3	41.5	1.66	0.10					

	BAU 2050	73.3	16.7	10.6	30.9	40.2	1.55	0.09					
	WWS 2050	30.5	13.0	13.4	46.4	26.1	1.13	0.04	-43.7	-8.1	-6.6	-58.4	2.11
Benin	BAU 2018	5.9	37.7	8.2	1.8	51.9	0.45	0.00					
	BAU 2050	11.0	26.0	9.2	2.0	62.5	0.48	0.00					
	WWS 2050	2.6	22.3	11.2	6.8	59.1	0.59	0.00	-69.2	-1.2	-6.1	-76.5	7.17
Bolivia	BAU 2018	10.0	12.8	3.4	31.4	49.6	2.75	0.00					
	BAU 2050	18.3	8.9	3.2	26.6	59.4	2.04	0.00					
	WWS 2050	5.2	13.7	7.5	41.8	34.1	3.05	0.00	-42.9	-23.1	-5.8	-71.7	2.96
Bosnia & Herz.	BAU 2018	6.2	37.0	7.5	27.9	26.7	0.90	0.00					
	BAU 2050	9.0	38.6	9.1	25.6	26.0	0.69	0.00					
	WWS 2050	3.8	36.1	13.3	34.3	15.9	0.45	0.00	-40.2	-9.0	-8.4	-57.7	1.38
Botswana	BAU 2018	2.8	32.5	4.8	17.2	43.5	1.44	0.58					
	BAU 2050	5.4	24.8	6.1	17.1	49.9	1.50	0.62					
	WWS 2050	2.1	22.1	11.3	33.1	30.3	2.05	1.19	-52.3	-2.2	-7.6	-62.1	1.98
Brazil	BAU 2018	325.6	10.8	5.2	42.4	36.2	5.03	0.37					
	BAU 2050	591.3	8.8	5.1	42.1	38.8	4.83	0.33					
	WWS 2050	272.1	10.8	8.2	58.0	18.6	3.68	0.72	-37.0	-11.5	-5.5	-54.0	2.14
Brunei	BAU 2018	2.7	7.7	7.6	56.5	26.7	0.00	1.48					
	BAU 2050	5.2	8.2	10.3	48.2	31.9	0.00	1.38					
	WWS 2050	1.5	19.3	28.1	25.8	25.8	0.00	0.97	-37.1	-29.4	-5.0	-71.5	1.44
Bulgaria	BAU 2018	14.8	20.0	10.2	34.8	33.4	1.67	0.00					
	BAU 2050	22.4	23.1	13.0	30.3	32.3	1.27	0.00					
	WWS 2050	10.0	27.2	19.1	35.6	17.3	0.78	0.00	-36.4	-11.3	-7.6	-55.3	1.31
Cambodia	BAU 2018	9.6	44.5	5.8	20.9	28.1	0.00	0.65					
	BAU 2050	17.3	34.5	7.0	21.6	36.2	0.00	0.66					
	WWS 2050	6.8	23.2	11.4	42.6	22.6	0.00	0.33	-52.0	-1.1	-7.5	-60.5	2.93
Cameroon	BAU 2018	9.9	64.5	15.2	5.9	12.9	0.07	1.44					
	BAU 2050	15.8	52.7	19.4	7.5	18.3	0.09	1.88					
	WWS 2050	4.3	40.4	16.5	22.5	16.0	0.25	4.38	-63.6	-0.9	-8.2	-72.6	2.37
Canada	BAU 2018	320.9	14.9	11.0	42.3	28.8	3.00	0.03					
	BAU 2050	442.5	13.4	11.8	45.5	26.5	2.76	0.02					
	WWS 2050	170.3	16.1	19.0	44.1	18.8	1.99	0.04	-32.8	-22.7	-6.1	-61.5	1.44
Chile	BAU 2018	38.8	15.8	6.5	39.7	35.2	2.51	0.20					
	BAU 2050	67.5	14.7	10.3	38.9	33.4	2.37	0.22					
	WWS 2050	34.9	12.5	11.5	57.5	16.4	1.79	0.42	-36.4	-4.8	-7.0	-48.3	1.76
China	BAU 2018	2,798.8	16.4	4.4	57.1	16.4	2.14	3.62					
	BAU 2050	4,970.5	17.6	4.5	48.7	24.9	1.47	2.83					
	WWS 2050	2,382.8	15.9	5.4	63.7	10.2	1.18	3.56	-31.5	-14.3	-6.3	-52.1	1.78
Colombia	BAU 2018	43.8	18.7	5.0	32.3	37.4	0.75	5.90					
	BAU 2050	70.5	16.5	5.2	31.6	40.9	0.62	5.30					
	WWS 2050	27.5	18.9	8.6	45.6	22.6	0.58	3.68	-43.5	-11.0	-6.5	-61.0	2.00
Congo	BAU 2018	2.7	57.4	13.8	5.5	23.3	0.00	0.00					
	BAU 2050	4.6	45.4	17.7	6.2	30.7	0.00	0.00					
	WWS 2050	1.3	38.3	23.3	12.6	25.8	0.00	0.00	-60.9	-2.0	-8.3	-71.2	2.23
Congo, DR	BAU 2018	26.0	90.2	0.1	4.4	4.2	1.03	0.00					
	BAU 2050	35.8	84.4	0.3	6.7	6.9	1.64	0.00					
	WWS 2050	8.5	68.5	1.0	22.2	7.0	1.29	0.00	-65.2	-0.6	-10.6	-76.4	3.67
Costa Rica	BAU 2018	5.5	11.3	9.6	23.7	52.9	1.82	0.65					
	BAU 2050	8.6	11.6	10.6	20.0	55.6	1.57	0.56					
	WWS 2050	3.9	17.4	16.8	34.7	29.2	1.51	0.42	-46.4	-1.5	-7.2	-55.0	1.88
Côte d'Ivoire	BAU 2018	10.0	59.3	9.6	9.0	20.8	1.33	0.01					
	BAU 2050	16.6	46.9	12.7	10.6	28.2	1.59	0.02					
	WWS 2050	5.1	35.9	16.6	23.5	22.3	1.59	0.04	-58.6	-2.0	-8.5	-69.0	2.40
Croatia	BAU 2018	10.0	30.4	10.8	24.7	31.0	3.11	0.00					
	BAU 2050	14.8	31.9	14.0	22.1	29.6	2.37	0.00					
	WWS 2050	6.0	30.4	21.7	27.9	18.8	1.32	0.00	-42.7	-8.1	-8.5	-59.2	1.54
Cuba	BAU 2018	11.0	15.0	3.3	55.6	14.1	2.56	9.41					
	BAU 2050	15.8	16.4	4.1	52.0	16.6	2.35	8.55					
	WWS 2050	9.0	18.0	5.4	63.8	8.6	1.16	2.99	-31.8	-4.9	-6.2	-42.9	2.48
Curacao	BAU 2018	3.2	3.3	0.9	15.2	80.6	0.00	0.00					
	BAU 2050	5.2	2.4	1.0	14.1	82.6	0.00	0.00					

	WWS 2050	1.4	4.1	2.8	14.3	78.7	0.00	0.00	-59.4	-9.4	-4.1	-72.8	9.03
Cyprus	BAU 2018	2.8	15.2	11.2	11.9	58.8	2.06	0.80					
	BAU 2050	4.2	16.7	15.3	9.6	56.2	1.59	0.62					
	WWS 2050	1.8	26.2	25.4	15.6	30.6	1.49	0.69	-46.4	-2.0	-8.3	-56.6	1.56
Czech Republic	BAU 2018	35.8	25.6	11.5	34.3	26.1	2.29	0.15					
	BAU 2050	43.9	25.6	12.4	33.8	26.1	1.97	0.13					
	WWS 2050	18.0	20.0	16.5	43.7	18.3	1.35	0.06	-41.1	-11.2	-6.7	-59.0	1.56
Denmark	BAU 2018	21.9	26.7	12.1	20.4	36.5	4.29	0.03					
	BAU 2050	26.1	27.8	13.5	21.2	33.6	3.86	0.03					
	WWS 2050	9.7	25.3	20.3	27.4	23.6	3.42	0.01	-48.1	-8.2	-6.6	-62.8	1.71
Dominican Rep.	BAU 2018	9.1	21.3	6.7	25.5	44.1	2.36	0.00					
	BAU 2050	14.0	16.9	7.6	25.4	48.0	2.14	0.00					
	WWS 2050	6.3	17.3	11.8	42.6	25.6	2.63	0.00	-44.9	-2.9	-7.3	-55.1	1.88
Ecuador	BAU 2018	18.4	12.7	7.3	17.9	51.3	2.59	8.15					
	BAU 2050	28.0	10.3	7.7	16.9	55.9	2.22	7.05					
	WWS 2050	10.0	14.6	12.8	29.2	37.7	1.25	4.48	-53.1	-4.9	-6.2	-64.2	2.03
Egypt	BAU 2018	83.2	22.4	5.5	39.6	30.1	2.30	0.10					
	BAU 2050	186.8	19.5	7.0	34.1	37.3	2.07	0.08					
	WWS 2050	88.8	22.8	11.4	47.7	16.1	2.04	0.04	-32.8	-11.9	-7.8	-52.4	1.75
El Salvador	BAU 2018	3.7	20.9	5.7	23.5	48.6	0.00	1.29					
	BAU 2050	5.5	16.6	7.0	21.3	53.8	0.00	1.26					
	WWS 2050	2.4	17.0	12.2	38.7	29.9	0.00	2.26	-47.6	-1.4	-7.5	-56.5	1.92
Equator. Guinea	BAU 2018	3.1	5.4	2.3	75.6	15.4	0.00	1.27					
	BAU 2050	6.6	4.3	2.5	75.4	16.7	0.00	1.20					
	WWS 2050	4.1	3.4	2.5	87.3	6.4	0.00	0.54	-29.7	-3.8	-3.4	-36.9	10.19
Eritrea	BAU 2018	0.7	73.1	7.0	3.5	16.3	0.00	0.00					
	BAU 2050	1.1	61.7	10.0	4.5	23.7	0.00	0.00					
	WWS 2050	0.3	49.9	15.2	12.7	22.2	0.00	0.00	-61.8	-0.8	-9.6	-72.2	2.32
Estonia	BAU 2018	4.8	25.8	13.4	24.3	32.8	3.42	0.30					
	BAU 2050	6.0	26.4	14.9	25.7	29.8	2.96	0.27					
	WWS 2050	2.1	23.9	24.8	27.5	20.9	2.27	0.60	-45.6	-12.8	-6.6	-65.0	1.30
Ethiopia	BAU 2018	55.0	86.7	1.4	3.7	7.3	0.45	0.45					
	BAU 2050	76.9	79.5	2.2	5.2	11.8	0.63	0.63					
	WWS 2050	18.0	64.1	4.4	17.4	13.0	0.54	0.54	-66.1	-0.2	-10.2	-76.5	6.36
Finland	BAU 2018	36.2	19.0	11.1	46.9	19.6	2.62	0.71					
	BAU 2050	42.6	21.0	13.0	44.3	18.8	2.35	0.65					
	WWS 2050	22.3	18.1	14.6	55.4	10.2	1.39	0.26	-34.3	-6.9	-6.5	-47.7	1.61
France	BAU 2018	204.6	23.9	15.0	23.6	34.4	2.85	0.34					
	BAU 2050	248.6	25.0	16.8	23.1	32.3	2.52	0.30					
	WWS 2050	111.6	24.2	21.7	30.8	21.4	1.70	0.18	-40.2	-6.3	-8.6	-55.1	1.35

2018 BAU values are from IEA (2022). These values are projected to 2050 using the U.S. Energy Information Administration "reference scenario" projections [S5], as described in the text. The EIA projections account for policies, population growth, modest economic and energy growth, some modest renewable energy additions, and modest energy efficiency measures and reduced energy use in each sector. The transportation demand includes, among other demands, energy produced in each country for aircraft and shipping. 2050 WWS values are estimated from 2050 BAU values assuming electrification of end-uses and effects of additional energy-efficiency measures beyond those in the BAU case, using the factors from Table S3. In the case of the industrial sector, the factors are applied after accounting for the change in energy between BAU and WWS during steel manufacturing due to purifying iron using green hydrogen in a shaft furnace instead of purifying it using coke in a blast furnace (Table S7), and during ammonia manufacturing due to using green hydrogen instead of gray hydrogen (Table S7). Multiply annual-average demand (GW) by 8,760 hours per year to obtain annual energy per year (GWh/y) consumed.

Table S5. 2018 BAU, 2050 BAU , and 2050 WWS Power Demand, Related to STAR Methods.
Same as Table S4, but for countries alphabetically from G-O.

Country	Scenario	(a) Total annual-average end-use demand (GW)	(b) Resi-den-tial % of total	(c) Co m-mer cial % of total	(d) Ind us-try % of total	(e) Tra ns-port % of total	(f) Ag-for-fish % of total	(g) Mil-itary-other % of total	(h) % change end-use dem-and with WWS due to higher work: energy ratio	(i) % change end-use demand with WWS due to elim-inating up-stream	(j) % change end-use demand with WWS due to effic-iency be-yond BAU	(k) Over-all % change in end-use demand with WWS	(l) WWS :BAU elec-tricity dem-and
Gabon	BAU 2018	6.1	27.9	0.9	65.8	5.2	0.09	0.11					
	BAU 2050	11.8	20.0	1.1	72.6	6.1	0.09	0.11					
	WWS 2050	7.3	9.0	1.1	87.2	2.5	0.10	0.06	-31.2	-4.1	-3.5	-38.7	10.39
Georgia	BAU 2018	5.6	29.0	12.1	19.8	34.5	0.64	3.90					
	BAU 2050	8.6	29.9	15.3	15.8	35.4	0.49	3.03					
	WWS 2050	3.6	23.2	23.2	31.5	16.1	0.44	5.63	-40.2	-7.7	-10.2	-58.0	1.47
Germany	BAU 2018	301.7	23.8	12.8	32.0	29.8	1.58	0.03					
	BAU 2050	361.0	23.7	13.8	31.4	29.7	1.39	0.03					
	WWS 2050	154.6	18.7	16.7	44.8	18.9	0.88	0.01	-41.4	-8.3	-7.4	-57.2	1.64
Ghana	BAU 2018	10.7	40.4	4.8	17.4	35.8	1.61	0.00					
	BAU 2050	20.7	32.0	6.1	18.3	41.9	1.63	0.00					
	WWS 2050	8.4	29.6	8.9	35.7	24.9	0.81	0.00	-50.4	-1.2	-8.0	-59.6	2.05
Gibraltar	BAU 2018	5.6	0.0	0.1	0.1	99.5	0.00	0.36					
	BAU 2050	6.0	0.0	0.1	0.1	99.4	0.00	0.37					
	WWS 2050	1.5	0.0	0.4	0.2	98.2	0.00	1.19	-69.5	-1.9	-4.2	-75.6	49.98
Greece	BAU 2018	26.8	19.0	9.1	23.9	45.4	1.39	1.14					
	BAU 2050	32.5	19.5	12.1	25.6	40.6	1.25	1.01					
	WWS 2050	13.0	24.4	21.9	26.1	25.1	1.95	0.51	-40.7	-11.9	-7.5	-60.1	1.40
Guatemala	BAU 2018	16.2	60.2	3.6	8.4	27.7	0.00	0.00					
	BAU 2050	20.2	49.7	4.3	9.4	36.7	0.00	0.00					
	WWS 2050	5.8	38.3	9.0	23.1	29.6	0.00	0.00	-60.8	-1.8	-8.6	-71.2	2.68
Haiti	BAU 2018	4.6	74.7	1.6	8.8	14.9	0.00	0.00					
	BAU 2050	5.1	66.4	1.5	10.3	21.9	0.00	0.00					
	WWS 2050	1.3	47.2	1.5	30.7	20.6	0.00	0.00	-64.9	-0.5	-8.9	-74.3	15.33
Honduras	BAU 2018	6.0	40.9	9.4	15.0	32.9	1.72	0.09					
	BAU 2050	8.2	33.1	10.2	14.8	40.1	1.66	0.08					
	WWS 2050	3.0	26.2	14.7	32.3	25.8	0.89	0.05	-54.1	-0.8	-8.1	-62.9	2.18
Hong Kong	BAU 2018	36.0	4.9	10.7	8.2	76.2	0.00	0.03					
	BAU 2050	82.6	4.7	11.6	6.6	77.0	0.00	0.02					
	WWS 2050	29.8	8.7	23.6	13.1	54.6	0.00	0.03	-55.4	-2.0	-6.5	-63.9	2.24
Hungary	BAU 2018	25.9	29.8	10.8	30.0	26.0	3.29	0.19					
	BAU 2050	31.7	30.1	10.9	29.1	26.8	2.87	0.17					
	WWS 2050	12.6	22.5	13.6	42.9	18.6	2.32	0.12	-43.5	-9.2	-7.6	-60.3	1.75
Iceland	BAU 2018	5.0	13.5	13.7	42.1	23.0	7.43	0.27					
	BAU 2050	5.6	14.4	14.6	41.5	22.2	7.01	0.26					
	WWS 2050	3.2	9.1	13.5	62.6	10.8	3.90	0.11	-34.9	-2.1	-5.9	-43.0	1.21
India	BAU 2018	797.9	29.0	4.3	40.8	18.3	4.88	2.67					
	BAU 2050	1,870.8	20.3	4.0	40.5	28.0	4.55	2.65					
	WWS 2050	951.6	15.9	3.8	60.3	12.9	5.00	2.05	-36.0	-6.4	-6.7	-49.1	2.40
Indonesia	BAU 2018	215.4	21.5	3.7	38.8	34.7	1.13	0.18					
	BAU 2050	423.9	16.1	4.6	37.2	40.9	1.05	0.16					
	WWS 2050	191.9	14.7	7.4	55.9	21.2	0.63	0.07	-42.7	-6.1	-6.0	-54.7	2.77
Iran	BAU 2018	253.8	27.9	5.8	35.7	26.3	4.09	0.22					
	BAU 2050	444.0	24.0	5.1	38.3	28.1	4.35	0.24					
	WWS 2050	186.3	17.4	5.7	58.7	13.2	4.55	0.44	-39.5	-11.2	-7.3	-58.0	2.82
Iraq	BAU 2018	36.7	19.5	0.8	32.2	44.2	0.00	3.36					

	BAU 2050	62.1	17.9	1.0	32.5	44.9	0.00	3.69					
	WWS 2050	23.1	27.0	2.1	35.0	28.3	0.00	7.61	-42.6	-13.8	-6.3	-62.7	1.99
Ireland	BAU 2018	16.7	21.7	11.6	22.7	42.0	1.97	0.00					
	BAU 2050	18.9	21.2	13.3	22.6	40.9	1.88	0.00					
	WWS 2050	8.0	19.2	16.9	38.6	23.9	1.40	0.00	-45.7	-4.2	-7.7	-57.6	1.75
Israel	BAU 2018	21.5	12.9	10.3	24.7	46.0	1.58	4.52					
	BAU 2050	26.1	15.1	14.2	24.8	40.4	1.45	4.07					
	WWS 2050	12.8	24.0	21.8	28.8	19.1	2.31	3.98	-35.2	-7.4	-8.4	-51.0	1.28
Italy	BAU 2018	168.4	25.2	13.3	25.8	33.2	2.39	0.09					
	BAU 2050	215.7	24.1	13.9	24.5	35.5	2.01	0.07					
	WWS 2050	83.6	18.8	20.4	34.7	24.6	1.61	0.04	-42.3	-11.1	-7.8	-61.2	1.52
Jamaica	BAU 2018	3.7	5.4	7.7	38.7	47.7	0.50	0.00					
	BAU 2050	5.5	5.5	6.4	35.0	52.6	0.44	0.00					
	WWS 2050	2.6	7.5	4.6	59.3	28.4	0.19	0.00	-47.8	-1.0	-4.8	-53.7	4.14
Japan	BAU 2018	370.8	15.2	17.4	36.1	29.5	1.66	0.19					
	BAU 2050	355.4	15.9	19.1	34.4	29.2	1.24	0.17					
	WWS 2050	186.3	15.8	20.6	47.2	15.7	0.57	0.06	-31.2	-8.6	-7.8	-47.6	1.52
Jordan	BAU 2018	9.1	21.3	7.3	13.9	50.2	3.40	3.87					
	BAU 2050	15.8	21.1	7.3	14.5	49.6	3.64	3.84					
	WWS 2050	6.9	31.6	10.9	22.3	26.9	6.52	1.76	-44.9	-3.3	-8.2	-56.4	1.51
Kazakhstan	BAU 2018	65.4	23.1	10.7	45.7	14.0	3.36	3.06					
	BAU 2050	87.2	22.1	11.2	45.6	15.2	3.00	2.82					
	WWS 2050	33.6	18.8	10.0	57.4	10.0	1.96	1.82	-41.4	-15.0	-5.0	-61.4	1.97
Kenya	BAU 2018	23.6	69.4	0.6	7.7	21.6	0.28	0.36					
	BAU 2050	37.1	57.1	1.2	9.8	31.1	0.35	0.45					
	WWS 2050	10.4	41.5	3.2	28.1	26.6	0.25	0.32	-62.5	-0.6	-8.8	-71.9	4.08
Korea, DPR	BAU 2018	6.9	3.1	0.0	52.1	8.9	0.00	35.95					
	BAU 2050	13.3	1.9	0.0	51.7	10.7	0.00	35.70					
	WWS 2050	7.4	0.6	0.0	72.0	4.7	0.00	22.73	-37.1	-2.3	-5.4	-44.8	2.59
Korea, Rep. of	BAU 2018	217.4	13.1	13.1	40.8	30.5	1.60	0.81					
	BAU 2050	304.9	11.4	15.2	42.5	28.8	1.49	0.66					
	WWS 2050	154.4	8.4	20.1	56.1	13.4	1.65	0.26	-32.5	-9.6	-7.3	-49.4	1.47
Kosovo	BAU 2018	2.0	37.5	10.1	22.0	28.4	2.02	0.00					
	BAU 2050	3.0	41.7	11.8	17.9	27.1	1.56	0.00					
	WWS 2050	1.4	43.4	15.2	25.7	14.3	1.35	0.00	-40.7	-3.5	-10.2	-54.3	1.23
Kuwait	BAU 2018	31.3	12.3	3.3	53.1	30.8	0.51	0.00					
	BAU 2050	57.4	16.0	4.0	50.7	28.9	0.52	0.00					
	WWS 2050	23.5	28.9	7.6	46.1	16.5	0.99	0.00	-31.4	-21.7	-5.9	-59.0	1.50
Kyrgyzstan	BAU 2018	5.5	62.8	7.6	15.8	12.3	0.63	0.94					
	BAU 2050	7.3	62.7	8.3	14.6	13.1	0.56	0.82					
	WWS 2050	3.4	61.7	7.9	22.1	6.7	0.75	0.73	-40.7	-1.6	-11.0	-53.3	1.20
Lao PDR	BAU 2018	4.2	40.3	12.1	13.3	34.2	0.06	0.00					
	BAU 2050	7.6	32.4	9.7	14.0	43.9	0.07	0.00					
	WWS 2050	2.8	26.6	12.5	31.9	28.8	0.15	0.00	-54.5	-0.8	-7.8	-63.2	2.00
Latvia	BAU 2018	5.7	28.5	13.7	23.1	30.2	4.35	0.14					
	BAU 2050	8.1	29.5	16.6	20.1	30.2	3.50	0.11					
	WWS 2050	3.2	22.8	21.8	33.4	19.7	2.22	0.05	-50.8	-2.6	-6.8	-60.2	2.05
Lebanon	BAU 2018	7.3	18.8	5.3	13.9	55.3	0.00	6.71					
	BAU 2050	13.2	20.3	6.3	14.3	52.5	0.00	6.74					
	WWS 2050	6.2	28.9	10.5	26.0	24.6	0.00	10.06	-43.3	-1.0	-9.1	-53.4	1.30
Libya	BAU 2018	14.4	13.4	1.5	25.3	55.3	1.00	3.45					
	BAU 2050	31.4	12.8	2.0	23.5	57.4	0.97	3.35					
	WWS 2050	13.2	19.1	3.7	39.1	30.1	1.81	6.22	-48.3	-3.2	-6.5	-58.0	2.40
Lithuania	BAU 2018	8.6	22.6	10.0	28.8	36.9	1.66	0.11					
	BAU 2050	12.6	23.7	12.0	26.7	36.2	1.33	0.08					
	WWS 2050	5.0	21.4	16.7	37.5	23.3	1.00	0.04	-43.9	-10.5	-6.0	-60.4	2.01
Luxembourg	BAU 2018	5.8	11.3	10.9	15.4	61.9	0.52	0.00					
	BAU 2050	6.5	11.5	12.3	15.6	60.1	0.50	0.00					
	WWS 2050	2.5	9.0	17.1	31.0	42.5	0.36	0.00	-53.2	-2.3	-6.6	-62.2	2.12
Macedonia, Nor.	BAU 2018	2.5	25.6	11.2	24.1	38.1	1.06	0.00					
	BAU 2050	3.8	31.1	13.6	19.3	35.3	0.80	0.00					

	WWS 2050	1.9	36.1	17.1	27.8	18.3	0.73	0.00	-37.7	-2.6	-9.7	-50.0	1.29
Malaysia	BAU 2018	79.1	5.6	7.4	45.0	40.2	1.71	0.00					
	BAU 2050	169.0	5.4	8.7	40.3	44.1	1.46	0.00					
	WWS 2050	80.7	8.0	13.6	56.3	21.4	0.71	0.00	-38.6	-7.8	-5.8	-52.3	1.99
Malta	BAU 2018	3.8	3.0	4.2	2.1	90.4	0.24	0.07					
	BAU 2050	5.5	4.2	5.9	1.7	88.0	0.19	0.06					
	WWS 2050	1.7	10.0	13.8	4.6	71.3	0.18	0.15	-62.4	-1.8	-5.6	-69.8	2.94
Mauritius	BAU 2018	2.3	8.0	5.8	12.0	73.8	0.23	0.12					
	BAU 2050	5.1	7.5	6.7	10.9	74.5	0.21	0.11					
	WWS 2050	1.9	13.2	13.0	24.4	48.9	0.29	0.23	-55.4	-1.5	-6.3	-63.2	2.15
Mexico	BAU 2018	189.1	12.7	2.9	38.4	41.0	3.11	1.91					
	BAU 2050	312.5	12.6	4.8	38.0	39.5	3.06	2.10					
	WWS 2050	133.7	14.6	6.5	52.1	20.4	2.55	3.84	-39.5	-11.6	-6.1	-57.2	1.79
Moldova, Rep.	BAU 2018	4.3	43.3	8.9	20.1	23.7	3.55	0.44					
	BAU 2050	6.0	44.1	10.9	17.6	24.2	2.83	0.37					
	WWS 2050	2.3	34.7	15.1	32.2	15.9	1.84	0.22	-50.5	-2.4	-8.9	-61.8	1.86
Mongolia	BAU 2018	5.4	25.2	7.9	33.6	18.7	2.21	12.30					
	BAU 2050	9.9	19.9	6.3	35.0	23.5	2.24	13.04					
	WWS 2050	3.9	17.2	4.0	53.9	14.1	1.37	9.43	-53.1	-3.4	-3.7	-60.2	2.34
Montenegro	BAU 2018	1.0	32.4	11.5	19.5	35.9	0.65	0.00					
	BAU 2050	1.6	36.6	15.0	15.0	32.9	0.48	0.00					
	WWS 2050	0.8	38.6	21.1	22.6	17.4	0.31	0.00	-37.2	-1.9	-10.9	-50.0	1.16
Morocco	BAU 2018	22.3	24.1	7.7	20.0	40.9	7.27	0.00					
	BAU 2050	44.6	17.6	8.7	20.2	46.3	7.25	0.00					
	WWS 2050	19.4	18.7	9.4	37.5	28.7	5.75	0.00	-48.3	-0.9	-7.2	-56.5	2.04
Mozambique	BAU 2018	6.8	37.7	14.7	23.9	22.9	0.08	0.78					
	BAU 2050	12.7	28.0	16.0	26.5	28.4	0.09	0.88					
	WWS 2050	5.3	17.6	9.2	54.7	16.8	0.10	1.65	-49.9	-1.5	-7.0	-58.4	1.61
Myanmar	BAU 2018	26.9	55.5	3.7	20.8	10.7	6.57	2.69					
	BAU 2050	44.7	45.9	4.2	23.1	16.7	7.17	2.95					
	WWS 2050	15.7	31.1	6.2	46.8	9.9	4.10	1.79	-52.6	-4.3	-8.0	-65.0	3.22
Namibia	BAU 2018	2.5	9.1	0.1	9.9	39.4	18.79	22.74					
	BAU 2050	5.1	5.6	0.1	9.8	43.5	17.96	23.00					
	WWS 2050	1.9	2.6	0.0	21.0	28.3	9.49	38.61	-54.2	-0.8	-7.1	-62.1	1.92
Nepal	BAU 2018	18.7	73.5	2.6	8.1	13.5	2.17	0.18					
	BAU 2050	28.5	63.8	2.6	10.2	20.5	2.60	0.23					
	WWS 2050	7.9	46.1	3.5	29.0	18.6	2.15	0.64	-62.6	-0.4	-9.2	-72.2	4.74
Netherlands	BAU 2018	88.4	14.4	10.2	30.8	38.9	5.69	0.10					
	BAU 2050	104.5	15.0	11.5	31.6	36.6	5.23	0.09					
	WWS 2050	41.6	12.0	16.0	43.8	23.7	4.49	0.04	-43.7	-10.0	-6.6	-60.2	2.09
New Zealand	BAU 2018	20.7	9.5	7.7	33.5	44.7	4.30	0.28					
	BAU 2050	32.4	10.0	10.6	36.9	38.0	4.12	0.33					
	WWS 2050	16.7	12.8	14.8	50.8	17.6	3.54	0.50	-36.4	-5.2	-6.9	-48.5	1.75
Nicaragua	BAU 2018	3.5	42.5	11.1	15.8	28.1	2.06	0.41					
	BAU 2050	4.7	34.4	11.7	16.4	34.9	2.05	0.45					
	WWS 2050	1.6	27.0	15.1	30.8	24.1	1.88	1.00	-53.6	-3.4	-8.0	-65.0	2.02
Niger	BAU 2018	4.2	78.4	1.4	4.0	16.1	0.03	0.00					
	BAU 2050	6.3	68.5	2.0	5.2	24.2	0.04	0.00					
	WWS 2050	1.6	58.8	3.4	15.3	22.4	0.14	0.00	-64.5	-0.9	-9.6	-75.0	3.41
Nigeria	BAU 2018	193.2	72.6	2.3	8.7	16.3	0.00	0.12					
	BAU 2050	294.0	61.3	3.3	11.0	24.2	0.00	0.15					
	WWS 2050	70.6	49.2	4.6	24.8	21.2	0.00	0.13	-64.0	-3.6	-8.3	-76.0	8.04
Norway	BAU 2018	34.0	16.1	11.5	49.5	21.0	1.73	0.20					
	BAU 2050	47.3	16.8	12.7	48.0	21.0	1.35	0.16					
	WWS 2050	20.7	26.5	20.0	40.3	11.8	1.37	0.07	-22.8	-25.9	-7.6	-56.3	1.00
Oman	BAU 2018	35.2	5.9	27.2	37.9	25.8	0.17	3.04					
	BAU 2050	59.9	8.0	21.6	41.0	26.1	0.19	3.11					
	WWS 2050	26.0	13.5	17.0	54.0	13.8	0.33	1.43	-40.6	-11.6	-4.5	-56.6	2.91

Table S6. 2018 BAU, 2050 BAU , and 2050 WWS Power Demand, Related to STAR Methods.
Same as Table S4, but for countries alphabetically from P-Z and for all countries combined.

Country	Scenario	(a) Total annual-average end-use demand (GW)	(b) Resi-den-tial % of total	(c) Com-mercial % of total	(d) Indus-try % of total	(e) Trans-port % of total	(f) Ag-for-fish % of total	(g) Mil-itary-other % of total	(h) % change end-use dem-and with WWS due to higher work: energy ratio	(i) % change end-use demand with WWS due to elim-inating up-stream	(j) % change end-use demand with WWS due to effic-iency be-yond BAU	(k) Over-all % change in end-use demand with WWS	(l) WWS :BAU elec-tricity dem-and
Pakistan	BAU 2018	124.3	46.6	3.3	27.1	21.6	1.07	0.33					
	BAU 2050	233.1	36.8	3.5	28.3	30.0	1.12	0.32					
	WWS 2050	96.0	25.9	4.8	52.6	14.4	2.09	0.16	-45.8	-5.0	-8.0	-58.8	2.95
Panama	BAU 2018	11.5	6.6	6.2	9.0	78.1	0.15	0.01					
	BAU 2050	18.5	5.5	6.8	7.4	80.1	0.12	0.01					
	WWS 2050	6.0	9.2	15.1	17.4	58.2	0.07	0.02	-60.0	-1.6	-5.8	-67.4	3.05
Paraguay	BAU 2018	8.8	26.7	6.2	25.7	41.4	0.00	0.00					
	BAU 2050	12.9	22.4	7.8	23.0	46.7	0.00	0.00					
	WWS 2050	5.7	20.9	13.6	40.2	25.3	0.00	0.00	-46.7	-1.4	-7.3	-55.4	2.15
Peru	BAU 2018	29.4	17.8	6.2	30.9	44.0	1.01	0.00					
	BAU 2050	47.4	13.0	6.0	28.8	51.3	0.88	0.00					
	WWS 2050	18.7	12.7	8.9	49.8	27.3	1.24	0.00	-42.8	-11.4	-6.3	-60.5	2.06
Philippines	BAU 2018	47.2	21.2	13.1	25.0	39.4	1.24	0.00					
	BAU 2050	93.9	17.0	12.5	23.4	45.9	1.18	0.00					
	WWS 2050	41.0	18.1	15.8	38.8	26.0	1.37	0.00	-45.8	-3.1	-7.4	-56.3	1.76
Poland	BAU 2018	103.8	25.0	10.2	29.5	30.3	5.04	0.00					
	BAU 2050	126.7	22.9	11.6	29.3	31.8	4.36	0.00					
	WWS 2050	48.9	17.8	17.7	41.4	20.6	2.52	0.00	-43.0	-12.4	-6.0	-61.4	1.70
Portugal	BAU 2018	25.2	14.0	10.4	31.1	42.0	2.43	0.14					
	BAU 2050	30.2	15.1	13.3	30.7	38.6	2.19	0.12					
	WWS 2050	13.5	16.3	20.5	38.6	22.9	1.58	0.05	-39.4	-8.8	-7.1	-55.3	1.58
Qatar	BAU 2018	44.1	5.7	2.2	70.1	20.9	0.00	1.07					
	BAU 2050	78.8	7.8	2.7	68.3	20.1	0.00	1.12					
	WWS 2050	33.2	13.8	4.9	67.6	11.6	0.00	2.07	-24.3	-29.5	-4.1	-57.9	2.74
Romania	BAU 2018	34.1	30.1	7.7	34.1	25.2	2.20	0.82					
	BAU 2050	48.4	31.9	9.2	31.3	25.1	1.79	0.65					
	WWS 2050	18.9	25.4	11.8	44.5	16.7	1.22	0.33	-44.6	-9.0	-7.3	-60.9	1.77
Russia	BAU 2018	683.1	28.8	7.2	39.1	23.0	1.86	0.00					
	BAU 2050	779.2	27.5	7.3	36.6	27.1	1.39	0.00					
	WWS 2050	264.7	24.6	10.7	49.3	14.2	1.30	0.00	-40.4	-19.3	-6.3	-66.0	1.72
Saudi Arabia	BAU 2018	188.4	9.2	7.7	45.7	37.0	0.30	0.03					
	BAU 2050	349.0	11.6	9.1	44.6	34.4	0.30	0.03					
	WWS 2050	183.6	16.2	13.5	53.9	15.9	0.44	0.04	-32.9	-8.0	-6.6	-47.4	2.15
Senegal	BAU 2018	3.7	39.9	6.4	15.0	37.0	0.36	1.30					
	BAU 2050	6.9	29.2	8.1	16.0	44.8	0.41	1.47					
	WWS 2050	2.6	21.4	13.6	32.1	29.1	0.83	2.98	-52.2	-1.4	-8.1	-61.7	2.21
Serbia	BAU 2018	12.5	30.0	9.4	34.6	24.1	1.80	0.00					
	BAU 2050	18.8	34.6	11.2	30.0	22.8	1.37	0.00					
	WWS 2050	8.9	37.8	13.6	35.0	12.7	0.92	0.00	-36.1	-8.5	-8.4	-53.0	1.26
Singapore	BAU 2018	95.4	1.0	2.6	13.9	82.4	0.00	0.04					
	BAU 2050	216.6	1.0	2.9	11.2	84.8	0.00	0.03					
	WWS 2050	69.7	2.2	6.8	22.4	68.5	0.00	0.07	-59.7	-3.6	-4.5	-67.8	4.60
Slovak Republic	BAU 2018	15.3	17.8	11.4	45.2	24.4	1.16	0.00					
	BAU 2050	20.0	16.8	11.7	42.0	28.6	0.94	0.00					
	WWS 2050	8.6	13.2	15.1	56.5	14.6	0.65	0.00	-32.8	-17.8	-6.4	-57.0	1.78
Slovenia	BAU 2018	7.1	20.0	8.0	28.4	41.7	1.37	0.45					

	BAU 2050	8.3	21.7	10.0	27.2	39.3	1.25	0.41					
	WWS 2050	3.9	18.8	14.5	42.6	23.3	0.62	0.18	-42.5	-3.5	-7.4	-53.5	1.60
South Africa	BAU 2018	117.6	15.1	6.9	48.1	26.2	2.55	1.21					
	BAU 2050	234.2	12.9	8.4	45.2	29.7	2.56	1.21					
	WWS 2050	103.2	15.1	10.6	54.6	16.8	1.99	0.94	-36.5	-13.9	-5.5	-55.9	1.63
South Sudan	BAU 2018	0.7	27.8	2.1	19.0	47.2	3.92	0.00					
	BAU 2050	1.4	21.4	2.1	17.0	55.5	4.05	0.00					
	WWS 2050	0.4	25.6	2.7	15.7	51.4	4.67	0.00	-55.8	-10.9	-5.7	-72.5	2.82
Spain	BAU 2018	136.5	14.4	10.5	29.5	42.6	2.66	0.31					
	BAU 2050	166.0	15.1	12.2	30.4	39.6	2.35	0.28					
	WWS 2050	69.0	17.8	18.3	36.2	25.7	1.67	0.27	-39.5	-12.1	-6.8	-58.4	1.57
Sri Lanka	BAU 2018	14.8	29.8	4.6	24.0	39.7	0.00	1.92					
	BAU 2050	28.6	22.1	5.0	23.3	47.7	0.00	1.81					
	WWS 2050	11.5	17.7	8.2	45.1	28.2	0.00	0.89	-51.8	-1.4	-6.4	-59.6	2.98
Sudan	BAU 2018	17.2	43.5	13.7	11.3	29.4	1.51	0.56					
	BAU 2050	32.0	34.3	15.2	12.6	35.6	1.65	0.59					
	WWS 2050	11.2	31.8	13.0	27.2	25.1	2.60	0.34	-56.6	-1.1	-7.3	-65.0	2.54
Suriname	BAU 2018	0.8	17.2	7.9	15.7	42.3	16.51	0.34					
	BAU 2050	1.2	16.0	9.0	14.8	45.8	14.13	0.32					
	WWS 2050	0.5	23.3	15.5	26.1	27.5	7.07	0.63	-49.0	-3.4	-7.7	-60.0	1.42
Sweden	BAU 2018	45.9	21.7	11.9	35.9	28.6	1.89	0.00					
	BAU 2050	55.4	24.0	14.1	32.6	27.7	1.63	0.00					
	WWS 2050	30.3	23.7	16.0	44.3	15.1	0.87	0.00	-33.1	-4.6	-7.6	-45.3	1.35
Switzerland	BAU 2018	26.5	25.3	15.9	19.5	37.8	0.53	1.03					
	BAU 2050	32.1	24.9	17.5	18.4	37.9	0.48	0.92					
	WWS 2050	14.3	23.6	21.6	28.3	25.4	0.71	0.40	-43.0	-3.7	-8.6	-55.2	1.30
Syria	BAU 2018	8.5	21.3	4.3	28.6	39.1	3.59	3.15					
	BAU 2050	14.4	19.1	4.1	29.8	39.9	3.67	3.36					
	WWS 2050	6.3	24.1	4.9	42.6	22.6	1.67	4.16	-42.3	-6.4	-7.2	-55.9	1.70
Taiwan	BAU 2018	80.4	9.6	8.4	53.4	26.7	1.03	0.81					
	BAU 2050	165.3	9.5	9.3	49.0	30.5	0.94	0.76					
	WWS 2050	89.9	11.7	11.8	60.8	14.1	0.77	0.83	-31.0	-7.7	-6.9	-45.6	1.39
Tajikistan	BAU 2018	3.9	27.6	7.7	29.1	14.9	6.55	14.22					
	BAU 2050	5.8	33.9	11.7	24.1	14.3	5.29	10.71					
	WWS 2050	3.4	36.4	15.2	31.9	6.0	6.92	3.59	-28.4	-1.1	-10.9	-40.3	1.13
Tanzania	BAU 2018	24.2	69.6	0.8	10.9	11.0	5.05	2.61					
	BAU 2050	38.1	57.3	1.4	14.8	15.8	7.03	3.65					
	WWS 2050	11.4	38.3	3.6	38.7	12.4	4.59	2.44	-60.9	-0.3	-8.7	-70.0	5.81
Thailand	BAU 2018	122.3	10.1	5.3	44.2	36.6	3.15	0.70					
	BAU 2050	257.5	8.1	6.1	38.9	43.5	2.72	0.65					
	WWS 2050	116.9	9.4	9.7	57.2	21.4	1.24	1.11	-39.0	-10.0	-5.6	-54.6	2.40
Togo	BAU 2018	2.8	66.5	10.1	4.6	18.9	0.00	0.00					
	BAU 2050	4.5	54.4	13	5.9	26.7	0.00	0.00					
	WWS 2050	1.2	44.0	12.7	18.9	24.0	0.00	0.00	-64.9	-0.5	-8.4	-73.8	3.24
Trinidad & Tob.	BAU 2018	9.6	5.0	1.2	73.8	20.0	0.00	0.00					
	BAU 2050	15.4	5.0	1.3	73.0	20.7	0.00	0.00					
	WWS 2050	8.5	5.3	3.1	84.2	8.8	0.00	0.00	4.0	-44.8	-4.1	-44.8	5.18
Tunisia	BAU 2018	11.6	24.9	8	28.2	32.9	6.02	0.00					
	BAU 2050	30.0	15.1	6.8	21.8	51.6	4.62	0.00					
	WWS 2050	10.7	17.6	11.6	44.8	21.8	4.10	0.00	-39.4	-17.7	-7.3	-64.4	2.13
Turkiye	BAU 2018	144.6	18.9	11.5	35.5	30.0	4.16	0.00					
	BAU 2050	173.7	19.3	12.9	34.2	29.9	3.69	0.00					
	WWS 2050	81.3	17.1	16.2	48.0	15.6	3.21	0.00	-37.4	-8.6	-7.3	-53.2	1.85
Turkmenistan	BAU 2018	28.0	1.8	34	18.6	22.8	1.62	21.06					
	BAU 2050	40.0	2.2	33.5	19.1	27.0	1.35	16.75					
	WWS 2050	9.2	6.2	30.8	26.0	18.4	4.59	15.54	-54.8	-18.8	-3.5	-77.0	3.31
Ukraine	BAU 2018	71.1	31.1	8	39.1	18.3	3.53	0.00					
	BAU 2050	104.2	33.9	9.5	34.7	19.1	2.77	0.00					
	WWS 2050	48.2	25.0	12.1	52.4	10.2	1.86	0.00	-35.5	-10.3	-8.0	-53.7	1.81
United Arab Em.	BAU 2018	108.5	4.6	4.2	43.5	44.6	0.00	3.08					
	BAU 2050	205.6	6.0	4.8	45.7	40.5	0.00	3.02					

	WWS 2050	110.9	8.3	6.8	63.1	17.3	0.00	4.32	-38.3	-2.2	-5.5	-46.0	3.49
United Kingdom	BAU 2018	195.3	25.8	11.6	22.9	37.8	1.01	0.84					
	BAU 2050	232.4	26.6	12.8	24.3	34.6	0.91	0.76					
	WWS 2050	87.9	23.9	18.8	31.3	24.7	0.84	0.38	-44.8	-9.3	-8.1	-62.2	1.58
United States	BAU 2018	2,172.8	16.6	13.3	25.7	41.9	1.29	1.24					
	BAU 2050	2,397.7	14.9	14.9	30.1	37.4	1.38	1.32					
	WWS 2050	959.5	18.7	19.4	37.9	20.0	1.05	2.58	-40.8	-12.2	-7.0	-60.0	1.57
Uruguay	BAU 2018	6.8	16.0	6.3	43.4	29.9	4.45	0.00					
	BAU 2050	10.0	15.4	7.5	39.5	33.6	4.00	0.00					
	WWS 2050	5.1	16.3	10.2	55.6	15.6	2.15	0.00	-38.1	-4.1	-6.4	-48.6	2.16
Uzbekistan	BAU 2018	48.5	30.8	9.9	37.7	15.9	4.51	1.26					
	BAU 2050	73.2	31.1	9.9	35.4	19.0	3.57	1.04					
	WWS 2050	21.2	28.8	11.2	41.9	8.5	9.20	0.70	-41.0	-22.9	-7.0	-71.0	2.02
Venezuela	BAU 2018	49.2	10.0	6.3	52.2	31.3	0.11	0.00					
	BAU 2050	78.7	10.0	6.8	50.7	32.4	0.10	0.00					
	WWS 2050	28.0	15.7	12.6	51.0	20.1	0.21	0.00	-36.8	-22.8	-4.9	-64.5	2.07
Vietnam	BAU 2018	80.8	16.5	4.7	54.6	22.1	2.06	0.00					
	BAU 2050	159.1	15.2	3.9	52.8	26.1	1.97	0.00					
	WWS 2050	98.6	14.7	3	70.9	10.1	1.35	0.00	-30.4	-1.2	-6.4	-38.0	2.08
Yemen	BAU 2018	3.0	27.7	3.5	19.3	44.0	2.08	3.40					
	BAU 2050	4.8	22.4	3.1	21.2	47.6	2.26	3.42					
	WWS 2050	1.7	28.1	3.1	34.1	30.4	1.24	2.92	-51.2	-5.2	-7.0	-63.4	2.49
Zambia	BAU 2018	13.0	60.4	1.2	29.8	7.3	0.52	0.80					
	BAU 2050	21.9	49.3	1.7	37.6	9.8	0.63	0.93					
	WWS 2050	10.2	27.1	2.3	64.1	5.3	0.68	0.51	-44.6	-0.6	-8.0	-53.2	2.76
Zimbabwe	BAU 2018	13.9	73.9	1.2	8.0	10.2	5.54	1.23					
	BAU 2050	21.5	63.2	2.1	10.6	14.8	7.69	1.57					
	WWS 2050	6.3	46.8	5.5	28.4	12.0	6.08	1.19	-60.1	-0.8	-9.7	-70.6	2.53
All Countries	**BAU 2018**	**13,102**	**20.8**	**8.2**	**38.1**	**29.2**	**2.22**	**1.52**					
	BAU 2050	**20,359**	**19.1**	**8**	**37.6**	**31.7**	**2.05**	**1.48**					
	WWS 2050	**8,970**	**17.3**	**10.4**	**52.4**	**16.2**	**1.82**	**1.83**	**-38.0**	**-11.3**	**-6.6**	**-55.9**	**1.87**

Table S7. Hydrogen Needed, Related to Star Methods.
2050 estimated mass of hydrogen needed per year for (a) steel manufacturing, (b) ammonia manufacturing, (c) long-distance hydrogen fuel cell-electric vehicles, (d) the sum of all of these by country and world region, (e) the power needed to produce and compress hydrogen for steel plus ammonia manufacturing, (f) the power needed to produce and compress hydrogen for transportation, and (g) the power needed to produce and compress hydrogen for steel and ammonia manufacturing and transportation. From ref. [S1]. Values are the same for all four cases (Cases I-IV).

Region or country	(a) 2050 Tg-H_2/y needed to purify iron by hydrogen direct reduction	(b) 2050 Tg-H_2/y needed to make NH_3	(c) 2050 Tg-H_2/y needed for HFC vehicles	(d) 2050 Total Tg-H_2/y produced for steel, ammonia, and vehicles = a+b+c	(e) 2050 Power needed to produce and compress H_2 for steel and ammonia (GW)	(f) 2050 power needed to produce and compress H_2 for transport (GW)	(g) 2050 power needed to produce and compress H_2 for steel, ammonia, and transport (GW) = e+f
Africa	**0.70**	**1.638**	**6.333**	**8.674**	**12.587**	**34.05**	**46.64**
Algeria	0.18	0.475	0.951	1.610	3.544	5.11	8.66
Angola	0	0	0.198	0.198	0	1.06	1.06
Benin	0	0	0.073	0.073	0	0.39	0.39
Botswana	0	0	0.037	0.037	0	0.20	0.20
Cameroon	0	0	0.049	0.049	0	0.26	0.26
Congo	0	0	0.026	0.026	0	0.14	0.14
Congo, DR	0	0	0.041	0.041	0	0.22	0.22
Côte d'Ivoire	0	0	0.091	0.091	0	0.49	0.49
Egypt	0.30	0.907	1.104	2.313	6.499	5.94	12.43
Equator. Guinea	0	0	0.020	0.020	0	0.11	0.11
Eritrea	0	0	0.006	0.006	0	0.03	0.03
Ethiopia	0	0	0.221	0.221	0	1.19	1.19
Gabon	0	0	0.015	0.015	0	0.08	0.08
Ghana	0	0	0.150	0.150	0	0.80	0.80
Kenya	0	0	0.200	0.200	0	1.08	1.08
Libya	0.05	0.005	0.176	0.230	0.291	0.95	1.24
Morocco	0	0	0.566	0.566	0	3.04	3.04
Mozambique	0	0	0.076	0.076	0	0.41	0.41
Namibia	0	0	0.044	0.044	0	0.24	0.24
Niger	0	0	0.021	0.021	0	0.11	0.11
Nigeria	0	0.153	0.407	0.560	0.824	2.19	3.01
Senegal	0	0	0.064	0.064	0	0.34	0.34
South Africa	0.17	0.097	1.161	1.426	1.425	6.24	7.67
South Sudan	0	0	0.018	0.018	0	0.10	0.10
Sudan	0	0	0.230	0.230	0	1.23	1.23
Tanzania	0	0	0.094	0.094	0	0.51	0.51
Togo	0	0	0.018	0.018	0	0.10	0.10
Tunisia	0	0	0.183	0.183	0	0.99	0.99
Zambia	0	0	0.043	0.043	0	0.23	0.23
Zimbabwe	0	0.001	0.052	0.053	0.005	0.28	0.29
Australia	**0.206**	**0.345**	**1.210**	**1.761**	**2.964**	**6.51**	**9.47**
Canada	**0.422**	**0.841**	**1.419**	**2.682**	**6.792**	**7.63**	**14.42**
Central America	**0.460**	**0.024**	**1.978**	**2.462**	**2.605**	**10.63**	**13.24**
Costa Rica	0	0	0.076	0.076	0	0.41	0.41
El Salvador	0	0	0.053	0.053	0	0.29	0.29
Guatemala	0	0	0.107	0.107	0	0.57	0.57
Honduras	0	0	0.056	0.056	0	0.30	0.30
Mexico	0.460	0.024	1.416	1.901	2.605	7.62	10.22
Nicaragua	0	0	0.030	0.030	0	0.16	0.16
Panama	0	0	0.240	0.240	0	1.29	1.29
Central Asia	**0.168**	**1.131**	**1.282**	**2.581**	**6.985**	**6.89**	**13.88**

Kazakhstan	0.168	0.039	0.190	0.397	1.112	1.02	2.13
Kyrgyz Republic	0	0	0.014	0.014	0	0.08	0.08
Pakistan	0	0.712	0.843	1.556	3.831	4.53	8.36
Tajikistan	0	0	0.017	0.017	0	0.09	0.09
Turkmenistan	0	0.142	0.123	0.265	0.766	0.66	1.42
Uzbekistan	0	0.237	0.095	0.332	1.277	0.51	1.79
China region	**47.05**	**8.420**	**13.13**	**68.60**	**298.2**	**70.60**	**368.8**
China	47.04	8.420	11.56	67.01	298.2	62.14	360.3
Hong Kong	0	0	1.507	1.507	0	8.10	8.10
Korea, DPR	0.014	0	0.026	0.040	0.073	0.14	0.21
Mongolia	0	0	0.040	0.040	0	0.21	0.21
Cuba	**0**	**0**	**0.067**	**0.067**	**0**	**0.36**	**0.36**
Europe	**5.828**	**3.687**	**13.59**	**23.11**	**51.16**	**73.07**	**124.2**
Albania	0	0	0.034	0.034	0	0.19	0.19
Austria	0.330	0.091	0.287	0.708	2.264	1.54	3.81
Belarus	0	0.165	0.140	0.305	0.886	0.75	1.64
Belgium	0.227	0.184	0.657	1.068	2.210	3.53	5.74
Bosnia-Herzeg.	0.040	0	0.056	0.096	0.215	0.30	0.52
Bulgaria	0	0.050	0.146	0.196	0.267	0.78	1.05
Croatia	0	0.080	0.094	0.174	0.430	0.51	0.94
Cyprus	0	0	0.038	0.038	0	0.20	0.20
Czech Rep.	0.211	0.020	0.194	0.426	1.243	1.05	2.29
Denmark	0	0	0.165	0.165	0	0.89	0.89
Estonia	0	0.004	0.033	0.037	0.022	0.18	0.20
Finland	0.135	0.017	0.151	0.303	0.818	0.81	1.63
France	0.514	0.177	1.655	2.347	3.720	8.90	12.62
Germany	1.419	0.503	1.813	3.734	10.333	9.75	20.08
Gibraltar	0	0	0.107	0.107	0	0.57	0.57
Greece	0	0.022	0.245	0.266	0.116	1.32	1.43
Hungary	0.032	0.093	0.136	0.261	0.674	0.73	1.40
Ireland	0	0	0.167	0.167	0	0.90	0.90
Italy	0.211	0.134	1.227	1.572	1.855	6.60	8.45
Kosovo	0	0	0.015	0.015	0	0.08	0.08
Latvia	0	0	0.056	0.056	0	0.30	0.30
Lithuania	0	0.182	0.107	0.289	0.979	0.57	1.55
Luxembourg	0	0	0.087	0.087	0	0.47	0.47
Macedonia	0	0	0.033	0.033	0	0.18	0.18
Malta	0	0	0.094	0.094	0	0.50	0.50
Moldova	0	0	0.030	0.030	0	0.16	0.16
Montenegro	0	0	0.013	0.013	0	0.07	0.07
Netherlands	0.319	0.453	0.648	1.421	4.156	3.48	7.64
Norway	0.004	0.071	0.162	0.238	0.406	0.87	1.28
Poland	0.195	0.488	0.698	1.381	3.674	3.75	7.43
Portugal	0	0	0.255	0.255	0	1.37	1.37
Romania	0.114	0.101	0.254	0.470	1.157	1.37	2.52
Serbia	0.060	0	0.097	0.157	0.322	0.52	0.84
Slovakia	0.168	0.077	0.064	0.309	1.315	0.34	1.66
Slovenia	0	0	0.067	0.067	0	0.36	0.36
Spain	0.217	0.091	1.441	1.748	1.652	7.75	9.40
Sweden	0.168	0	0.233	0.401	0.903	1.26	2.16
Switzerland	0	0.002	0.026	0.028	0.012	0.14	0.15
Ukraine	1.148	0.497	0.314	1.959	8.847	1.69	10.53
United Kingdom	0.314	0.186	1.554	2.053	2.687	8.35	11.04
Haiti region	**0**	**0**	**0.136**	**0.136**	**0**	**0.73**	**0.73**
Dominican Rep.	0	0	0.116	0.116	0	0.62	0.62
Haiti	0	0	0.020	0.020	0	0.11	0.11
Iceland	**0**	**0**	**0.025**	**0.025**	**0**	**0.14**	**0.14**
India region	**6.314**	**2.815**	**10.52**	**19.65**	**49.09**	**56.55**	**105.6**
Bangladesh	0	0.181	0.282	0.463	0.975	1.52	2.49
India	6.314	2.634	9.874	18.821	48.110	53.09	101.20
Nepal	0	0	0.131	0.131	0	0.70	0.70
Sri Lanka	0	0	0.231	0.231	0	1.24	1.24

Israel	**0**	**0**	**0.148**	**0.148**	**0**	**0.80**	**0.80**
Jamaica	**0**	**0**	**0.062**	**0.062**	**0**	**0.33**	**0.33**
Japan	**3.807**	**0.139**	**1.586**	**5.532**	**21.21**	**8.53**	**29.74**
Mauritius	**0**	**0**	**0.069**	**0.069**	**0**	**0.37**	**0.37**
Mideast	**3.065**	**3.178**	**7.887**	**14.13**	**33.57**	**42.41**	**75.97**
Armenia	0	0	0.008	0.008	0	0.05	0.05
Azerbaijan	0	0	0.089	0.089	0	0.48	0.48
Bahrain	0.076	0.082	0.040	0.198	0.850	0.22	1.07
Iran	1.760	0.777	1.643	4.180	13.641	8.83	22.47
Iraq	0	0.019	0.432	0.451	0.104	2.32	2.43
Jordan	0	0	0.125	0.125	0	0.67	0.67
Kuwait	0	0	0.251	0.251	0	1.35	1.35
Lebanon	0	0	0.062	0.062	0	0.33	0.33
Oman	0.092	0.374	0.204	0.669	2.503	1.09	3.60
Qatar	0.043	0.712	0.291	1.047	4.064	1.57	5.63
Saudi Arabia	0.330	0.928	2.260	3.518	6.768	12.15	18.92
Syria	0	0.004	0.120	0.125	0.023	0.65	0.67
Turkiye	0.563	0.080	1.168	1.811	3.457	6.28	9.74
UAE	0.200	0.201	1.160	1.561	2.157	6.24	8.39
Yemen	0	0	0.034	0.034	0	0.18	0.18
New Zealand	**0.038**	**0.027**	**0.204**	**0.269**	**0.349**	**1.10**	**1.45**
Philippines	**0**	**0**	**0.848**	**0.848**	**0**	**4.56**	**4.56**
Russia region	**3.325**	**3.525**	**1.962**	**8.811**	**36.83**	**10.55**	**47.38**
Georgia	0	0.043	0.030	0.073	0.232	0.16	0.39
Russia	3.325	3.482	1.932	8.739	36.596	10.39	46.99
South America	**1.879**	**1.107**	**6.043**	**9.028**	**16.05**	**32.49**	**48.54**
Argentina	0.190	0.138	0.645	0.972	1.762	3.47	5.23
Bolivia	0	0	0.115	0.115	0	0.62	0.62
Brazil	1.543	0.026	3.198	4.767	8.437	17.19	25.63
Chile	0.038	0	0.437	0.475	0.204	2.35	2.55
Colombia	0.009	0	0.376	0.384	0.048	2.02	2.07
Curacao	0	0	0.108	0.108	0	0.58	0.58
Ecuador	0	0	0.281	0.281	0	1.51	1.51
Paraguay	0.002	0	0.108	0.109	0.010	0.58	0.59
Peru	0	0.002	0.414	0.416	0.013	2.23	2.24
Suriname	0	0	0.010	0.010	0	0.05	0.05
Trinidad/Tobago	0.081	0.899	0.048	1.028	5.272	0.26	5.53
Uruguay	0	0	0.057	0.057	0	0.30	0.30
Venezuela	0.016	0.041	0.249	0.306	0.308	1.34	1.65
Southeast Asia	**0.731**	**1.803**	**10.61**	**13.14**	**13.62**	**57.04**	**70.66**
Brunei	0	0	0.023	0.023	0	0.12	0.12
Cambodia	0	0	0.124	0.124	0	0.66	0.66
Indonesia	0.162	1.274	2.616	4.052	7.722	14.06	21.79
Lao PDR	0	0	0.060	0.060	0	0.32	0.32
Malaysia	0.038	0.281	0.998	1.317	1.713	5.37	7.08
Myanmar	0	0	0.119	0.119	0	0.64	0.64
Singapore	0	0	3.940	3.940	0	21.18	21.18
Thailand	0	0	1.993	1.993	0	10.72	10.72
Vietnam	0.531	0.248	0.735	1.514	4.188	3.95	8.14
South Korea	**2.513**	**0**	**1.690**	**4.203**	**13.51**	**9.09**	**22.60**
Taiwan	**0.823**	**0**	**0.738**	**1.561**	**4.426**	**3.97**	**8.40**
United States	**1.392**	**3.023**	**9.711**	**14.13**	**23.73**	**52.21**	**75.95**
All regions	**78.72**	**31.70**	**91.24**	**201.7**	**593.7**	**490.6**	**1,084.3**

Column (e) is the sum of Columns (a) and (b), all multiplied by 47.1 TWh/Tg-H_2 (Footnote to Table S28) and divided by 8,760 hours per year; Column (f) is Column (c) multiplied by 47.1 TWh/Tg-H_2 and divided by 8,760 hours per year; Column (g) is the sum of Columns (e) and (f).

Table S8. Energy Demands by Sector and Region, Related to Star Methods.
2050 annual-average end-use electric plus heat demand (GW) by sector and region after energy in all sectors has been converted to WWS. Instantaneous demands can be higher or lower than annual-average demands. Values for each region equal the sum over all country values from Tables S4-S6 in each region, where Table S1 defines the regions. Values are the same for all four cases (Cases I-IV).

Region	(a) Total	(b) Residential	(c) Commercial	(e) Industrial	(f) Transport	(g) Agriculture-forestry-fishing	(h) Military-other
Africa	482.15	139.01	37.09	197.89	94.51	7.88	5.77
Australia	92.29	11.55	17.58	44.29	17.71	1.16	0.00
Canada	170.29	27.35	32.41	75.04	32.05	3.38	0.06
Central America	156.49	24.57	11.77	75.85	35.55	3.53	5.22
Central Asia	166.87	41.26	13.78	82.94	21.10	5.31	2.49
China region	2423.94	383.05	136.90	1529.15	259.78	28.11	86.96
Cuba	8.99	1.62	0.49	5.74	0.77	0.11	0.27
Europe	958.25	199.69	167.93	374.62	199.98	14.86	1.17
Haiti region	7.60	1.71	0.76	3.09	1.88	0.17	0.00
Iceland	3.22	0.29	0.43	2.02	0.35	0.13	0.00
India region	1006.84	166.59	39.06	601.98	130.83	48.45	19.93
Israel	12.77	3.07	2.79	3.68	2.44	0.30	0.51
Jamaica	2.56	0.19	0.12	1.51	0.73	0.01	0.00
Japan	186.33	29.53	38.46	87.92	29.25	1.06	0.12
Mauritius	1.89	0.25	0.25	0.46	0.93	0.01	0.00
Mideast	706.51	117.00	68.71	386.51	111.45	13.05	9.79
New Zealand	16.70	2.13	2.47	8.49	2.94	0.59	0.08
Philippines	41.02	7.41	6.49	15.90	10.66	0.56	0.00
Russia region	268.31	65.89	29.14	131.55	38.08	3.45	0.21
South America	468.71	61.32	43.17	254.84	93.02	12.81	3.56
Southeast Asia	584.57	69.27	46.74	316.53	145.03	5.20	1.80
South Korea	154.39	13.02	31.08	86.61	20.73	2.55	0.40
Taiwan	89.91	10.53	10.60	54.71	12.64	0.69	0.75
United States	959.46	179.38	190.27	363.44	191.60	10.05	24.73
Total 2050	**8970.1**	**1555.7**	**928.5**	**4704.7**	**1454.0**	**163.39**	**163.81**

Sector values in each region are obtained by multiplying the total WWS 2050 value for each country by the percentage of the total in each sector, given in Tables S4-S6, and summing the result over all countries in a region.

Table S9. Inflexible and Flexible Demands, Related to Star Methods.

Annual-average WWS all-sector inflexible and flexible demands (GW) for 2050 by region. "Total demand" is the sum of columns (b) and (c). "Flexible demand" is the sum of columns (d)-(g). DR is demand-response. "Demand for non-grid H_2" accounts for the production, compression, storage, and leakage of hydrogen (at a 0.3% leakage rate). Annual-average demands are distributed in time at 30-s resolution, as described in the text. Instantaneous demands, either flexible or inflexible, can be much higher or lower than annual-average demands. Column (h) shows the annual hydrogen mass production rate needed for steel and ammonia manufacturing and long-distance transport (shown by country in Table S7) in each region, estimated as the H_2 demand multiplied by 8,760 h/y and divided by 47.1 kWh/kg-H_2. Column (i) provides the estimated percent of 2050 annual average power demand already supplied in the annual average by WWS in 2018-2020. It is calculated as the 2018-2020 nameplate capacities from Table S10 multiplied by the capacity factors from Table S13, with the resulting average power outputs summed over all technologies, and the result divided by Column (a) here. Table S1 defines the regions. Values are the same for all four cases (Cases I-IV).

Region	(a) 2050 Total end-use dem-and (GW) =b+c	(b) Inflex-ible dem-and (GW)	(c) Flex-ible dem-and (GW) =d+e +f+g	(d) Cold dem-and subject to storage (GW)	(e) Low-temp-erature heat demand subject to storage (GW)	(f) Dem-and sub-ject to DR	(g) Dem-and for non-grid H_2 (GW)	(h) Non-grid H_2 needed (Tg-H_2/y)	(i) Percent of 2050 demand supplied by 2018-2020 WWS
Africa	482.1	233.1	249.0	9.5	30.7	162.3	46.6	8.67	3.62
Australia	92.3	47.8	44.5	0.5	2.9	31.7	9.5	1.76	12.24
Canada	170.3	86.7	83.6	0.6	9.7	58.8	14.4	2.68	26.11
Central America	156.5	72.7	83.8	1.7	5.3	63.6	13.2	2.46	8.76
Central Asia	166.9	89.2	77.7	0.2	7.6	56.0	13.9	2.58	5.73
China region	2,423.9	1,112	1,312	29.1	172.0	742.1	368.8	68.59	17.28
Cuba	9.0	4.4	4.6	0.3	0.4	3.6	0.4	0.07	0.67
Europe	958.3	426.9	531.4	11.4	128.8	267.0	124.2	23.11	22.50
Haiti region	7.6	3.7	3.9	0.1	0.3	2.7	0.7	0.14	6.24
Iceland	3.2	1.2	2.0	0.0	0.6	1.3	0.1	0.03	97.30
India region	1,006.8	470.1	536.8	11.7	42.1	377.3	105.7	19.65	4.92
Israel	12.8	6.7	6.1	0.3	0.7	4.3	0.8	0.15	7.98
Jamaica	2.6	1.1	1.4	0.0	0.0	1.1	0.3	0.06	2.57
Japan	186.3	102.3	84.1	0.4	7.2	46.8	29.7	5.53	14.67
Mauritius	1.9	0.6	1.2	0.1	0.1	0.7	0.4	0.07	3.30
Mideast	706.5	342.4	364.1	2.9	22.4	262.8	76.0	14.13	5.05
New Zealand	16.7	8.8	7.9	0.0	0.4	6.1	1.4	0.27	24.59
Philippines	41.0	17.9	23.1	1.7	2.8	14.1	4.6	0.85	8.93
Russia region	268.3	109.9	158.4	3.4	42.0	65.7	47.4	8.81	7.31
South America	468.7	222.2	246.5	7.3	13.1	177.6	48.5	9.03	21.32
Southeast Asia	584.6	257.4	327.2	8.1	19.3	229.1	70.7	13.14	4.54
South Korea	154.4	81.8	72.5	0.4	6.8	42.8	22.6	4.20	3.37
Taiwan	89.9	43.4	46.5	0.6	4.2	33.3	8.4	1.56	2.77
United States	959.5	484.5	475.0	7.4	53.4	338.2	75.9	14.12	10.41
Total	**8,970.1**	**4,227**	**4,743**	**97.5**	**572.9**	**2,989**	**1,084**	**201.7**	**12.37**

Table S10. Existing Nameplate Capacities, Related to Star Methods.
Existing nameplate capacity (GW) by WWS generator in each region in 2020 (except solar heat data are from 2018 and geothermal heat data are from 2019). Values are the same for all four cases (Cases I-IV). Ref. [S1] contain values for each country in each region.

Region or country	On-shore wind	Off-shore wind	Resi-dential roof PV	Com /gov roof PV	Utility PV	CSP with storage	Geo-ther-mal elec-tricity	Hydro	Tidal	Wave	Solar heat	Geoth ermal heat
Africa	6.483	0	1.751	1.751	5.253	1.076	0.8313	31.516	0.0004	0	2.654	0.1942
Australia	9.457	0	3.525	3.525	10.575	0.002	0.0001	7.45	0	0.001	6.451	0.0944
Canada	13.577	0	0.665	0.665	1.995	0	0	81.823	0	0.02	0.637	1.8313
Central America	9.327	0	1.389	1.389	4.167	0.014	1.6136	19.857	0	0	3.027	0.1655
Central Asia	1.774	0	0.492	0.492	1.476	0	0	24.956	0	0	0	0.0029
China region	278.48	9.996	50.793	50.793	152.380	0.521	0.0258	343.7	0	0.005	337.62	40.63
Cuba	0.012	0	0.033	0.033	0.098	0	0	0.068	0	0	0	0
Europe	184.90	25.015	32.227	32.227	96.680	2.3212	0.896	166.3	0.0001	0.2431	39.166	31.637
Haiti region	0.370	0	0.075	0.075	0.224	0	0	0.676	0	0	0	0
Iceland	0.002	0	0.001	0.001	0.004	0	0.756	2.086	0	0	0	2.373
India region	38.880	0	7.915	7.915	23.744	0.2285	0	49.08	0	0	9.457	0.3612
Israel	0.027	0	0.238	0.238	0.714	0.248	0	0.007	0	0	3.351	0.0824
Jamaica	0.099	0	0.019	0.019	0.056	0	0	0.03	0	0	0	0
Japan	4.373	0.085	13.400	13.400	40.200	0	0.525	22.379	0	0	2.58	2.5705
Mauritius	0.011	0	0.017	0.017	0.050	0	0	0.061	0	0	0.093	0
Mideast	10.262	0	2.415	2.415	7.246	0.2011	1.613	48.849	0	0	19.061	3.7754
New Zealand	0.784	0	0.028	0.028	0.085	0	0.984	5.354	0	0	0.112	0.518
Philippines	0.443	0	0.210	0.210	0.629	0	1.9279	3.7	0	0	0	0.0017
Russia region	0.966	0	0.286	0.286	0.857	0	0.074	51.976	0	0.002	0.018	0.5022
South America	25.769	0	2.524	2.524	7.572	0.1	0.04	175.63	0.0001	0	11.590	0.6207
Southeast Asia	2.206	0.099	4.359	4.359	13.078	0.005	2.1313	45.057	0	0	0.11	0.154
South Korea	1.515	0.136	2.915	2.915	8.745	0	0	1.806	0	0.256	1.324	1.4898
Taiwan	0.726	0.128	1.163	1.163	3.490	0	0	2.092	0	0	1.22	0.0001
United States	122.28	0.042	14.763	14.763	44.288	1.758	2.587	79.145	0	0	17.935	20.713
All regions	**712.72**	**35.50**	**141.20**	**141.20**	**423.61**	**6.47**	**14.01**	**1,164**	**0.0006**	**0.53**	**456.40**	**107.72**

Onshore and offshore wind, solar PV, CSP, geothermal electricity, and wave electricity are from ref. [S32]. Due to a lack of data, existing solar PV is assumed to be split 20% residential rooftop PV, 20% commercial/govt. rooftop PV, and 60% utility PV. Hydropower values are from ref. [S31]. Solar thermal values are for 2018 and from ref. [S33]. Tidal values are from various sources. Geothermal heat values are for 2019 and from Ref. [S34].

Table S11. Final Nameplate Capacities, Related to Star Methods.

Final 2050 total (existing plus new) nameplate capacity (GW) by generator needed in each region to supply 100% of all end-use demand plus losses continuously with WWS across all energy sectors in the region (as determined by LOADMATCH). Nameplate capacity equals the maximum possible instantaneous discharge rate. For Case I, the nameplate capacity of each generator in each region multiplied by the mean capacity factor for the generator in the region (from Table S13) gives the simulation-averaged power output from the generator in the region given in Table S14. Nameplate capacities are the same in Cases I-III. In Case IV, onshore and offshore wind utility PV, and/or CSP nameplate capacities were increased in some regions but were otherwise the same as in Cases I-III. Ref. [S1] contain finals nameplate capacities for each country in each region for Cases I-III.

	Onshore wind		Offshore wind		Res-ident-ial roof PV	Com /gov roof PV	Utility PV		CSP with storage		Geo-ther-mal elec-tric-ity	Hyd-ro	Wave	Tidal	Solar ther-mal	Geo-ther-mal heat
Region or country	Cases I-III	Case IV	Cases I-III	Case IV	All cases	All cases	Cases I-III	Case IV	Cases I-III	Case IV	All cases	All cases	All cases	All cases	All cases	All cases
Africa	524.1	612.8	151.9	151.9	350.0	633.7	536.5	643.8	27.7	27.7	3.611	31.52	3.507	0.832	2.654	0.194
Australia	83.0	98.7	19.2	107.1	38.1	65.2	257.8	257.8	4.86	4.86	0.400	7.450	0.576	0.500	6.451	0.094
Canada	219.0	219.0	36.9	36.9	14.0	102.0	43.3	43.3	0	0	5.000	81.82	0.942	2.000	0.637	1.831
Central America	414.3	414.3	93.0	173.5	51.0	114.9	251.4	251.4	8.05	32.2	10.69	19.86	2.390	0.325	3.027	0.166
Central Asia	244.6	244.6	21.2	21.2	116.7	163.3	211.9	219.0	7.97	7.97	0	24.96	1.640	0.021	0	0.003
China region	2,163	2,395	758.2	758.2	1,055	989.7	4,460	4,460	132	132	1.860	343.7	8.711	2.175	337.6	40.63
Cuba	17.6	42.6	4.81	4.81	4.76	14.9	19.7	30.1	0.48	0.48	0	0.068	0.051	0.047	0	0
Europe	1,204	1,204	454.7	454.7	342.6	500.0	1,406	1,406	16.2	16.2	3.186	166.3	4.809	5.576	39.17	31.64
Haiti region	5.3	18.6	2.92	2.92	2.17	9.04	18.4	29.9	0.38	0.38	0.680	0.676	0	0.052	0	0
Iceland	1.63	1.63	0	0	0	0	0	0	0	0	0.890	2.086	0.010	0.038	0	2.373
India region	668	1,114	108.0	108.0	89.5	1,361	2,097	2,097	92.9	92.9	0.280	49.08	4.938	0.874	9.457	0.361
Israel	3.34	4.63	5.42	5.42	1.15	14.32	57.7	77.7	0.63	0.63	0	0.007	0	0.009	3.351	0.082
Jamaica	0.36	0.76	3.23	3.23	2.68	2.67	3.76	7.87	0.16	0.16	0	0.030	0	0.020	0	0
Japan	10.8	10.8	303.8	303.8	22.3	15.0	367.9	546.1	0	0	1.460	22.38	2.667	2.200	2.580	2.571
Mauritius	0.10	0.10	3.37	3.93	0.43	0.26	3.95	4.70	0.04	0.04	0	0.061	0.013	0.007	0.093	0
Mideast	690.6	825.4	139.8	139.8	309.0	355.2	1,668	1,668	36.8	36.8	1.743	48.85	0.441	0.284	19.06	3.775
New Zealand	43.0	43.0	1.63	1.63	4.96	6.97	18.6	18.6	0.57	0.57	2.000	5.354	0.077	0.200	0.112	0.518
Philippines	23.9	23.9	20.3	20.3	15.2	54.4	126.2	189.2	1.60	1.60	5.730	3.700	0.563	0.500	0	0.002
Russia region	512.9	512.9	51.1	51.1	49.1	67.8	159.6	159.6	0	0	0.500	51.98	2.051	0.359	0.018	0.502
South America	1,511	1,511	94.9	94.9	117.6	258.4	295.4	295.4	23.1	23.1	5.350	175.6	4.828	1.188	11.59	0.621
Southeast Asia	54.3	54.3	1,574	1,574	491.0	577.3	1,057	1,554	28.7	28.7	13.76	45.06	4.421	0.635	0.110	0.154
South Korea	2.14	2.14	374.7	412.2	67.6	119.7	393.3	605.1	9.07	9.07	0	1.806	0	1.000	1.324	1.490
Taiwan	3.73	3.73	103.0	137.3	34.1	60.5	117.6	194.4	0	0	33.64	2.092	0.903	0.027	1.220	.0001
United States	1,639	2,085	377.3	377.3	234.2	347.8	2,182	2,518	32.9	32.9	6.520	79.15	6.752	0.350	17.94	20.71
All regions	**10,040**	**11,442**	**4,703**	**4,944**	**3,413**	**5,834**	**15,751**	**17,275**	**424.2**	**448.**	**97.30**	**1,164**	**50.29**	**19.22**	**456.4**	**107.7**

Table S12. Capacity Adjustment Factors, Related to Star Methods.

LOADMATCH capacity adjustment factors (CAFs), which show the ratio of the final nameplate capacity of a generator to meet demand continuously, after running LOADMATCH, to the pre-LOADMATCH initial nameplate capacity estimated to meet demand in the annual average. Thus, a CAF less than 1.0 means that the LOADMATCH-stabilized grid meeting continuous demand requires less than the nameplate capacity needed to meet annual-average demand (which is our initial, pre-LOADMATCH nameplate-capacity assumption). CAFs are the same in Cases I-IV, except that some of those differ in Case IV for onshore wind, offshore wind, utility PV, and/or CSP.

	Cases I-III				Case IV				Cases I-IV		
Region	(a) On-shore wind CAF	(b) Off-shore wind CAF	(c) Utility PV CAF	(d) CSP turbine factor	(e) Onshore wind CAF	(f) Off-shore wind CAF	(g) Utility PV CAF	(h) CSP turbine factor	(i) Res. Roof PV CAF	(j) Com./Gov Roof PV CAF	(k) Solar Thermal CAF
Africa	1.45	1	1	1	1.45	1	1.2	1	1	1	1
Australia	1.45	3.9	1.95	1	1.45	3.9	1.95	1	0.75	0.75	1
Canada	1.425	0.88	0.5	0	1.425	0.88	0.5	0	0.2	0.69	1
Central America	1.7	2.8	3	1	1.7	2.8	3	4	0.7	0.7	1
Central Asia	2	0.9	0.9	1	2	0.9	0.93	1	0.85	0.85	0
China region	1.55	0.7	1.7	1	1.55	0.7	1.7	1	0.55	0.55	1
Cuba	4.6	1.3	3.6	1	4.6	1.3	5.5	1	1	1.4	0
Europe	1.42	1	1.25	1	1.42	1	1.25	1	0.68	0.9	1
Haiti region	2.8	1	3.7	1	2.8	1	6	1	0.5	1	0
Iceland	0.47	0	0	0	0.47	0	0	0	0	0	0
India region	1.5	0.6	1.4	1.6	1.5	0.6	1.4	1.6	0.1	1.3	1
Israel	1.8	0.88	2.6	1	1.8	0.88	3.5	1	0.1	2.3	1
Jamaica	1.6	1.45	1.1	1	1.6	1.45	2.3	1	0.9	1	0
Japan	0.2	2	1.28	0	0.2	2	1.9	0	0.2	0.2	1
Mauritius	1	2.8	1.6	0.4	1	2.8	1.9	0.4	0.2	0.2	1
Mideast	2.45	0.8	1.25	1	2.45	0.8	1.25	1	0.7	0.75	1
New Zealand	3.05	0.4	1.95	0.7	3.05	0.4	1.95	0.7	0.6	0.6	1
Philippines	1.9	0.9	4	0.8	1.9	0.9	6	0.8	0.55	0.9	0
Russia region	1.79	0.55	0.8	0	1.79	0.55	0.8	0	0.31	0.32	1
South America	1.65	0.65	1.15	1	1.65	0.65	1.15	1	0.58	0.6	1
Southeast Asia	0.2	2.2	1.7	1	0.2	2.2	2.5	1	1	1	1
South Korea	0.1	2.2	1.3	1	0.1	2.2	2	1	0.9	2.5	1
Taiwan	0.5	2.4	1.21	0	0.5	2.4	2	0	0.7	2.5	1
United States	2.2	0.95	2.34	1	2.2	0.95	2.7	1	0.45	0.45	1

All generators not on this list have a CAF=1. Table S11 provides final nameplate capacities accounting for the CAFs. The initial estimated nameplate capacity of each generator in each country or region equals the final nameplate capacity divided by the CAF of the generator in the region that the country resides or in the region itself, respectively. The CAFs are also used to adjust the time-dependent wind and solar supplies provided from GATOR-GCMOM to LOADMATCH. Such supplies are calculated based on the initial nameplate capacities fed into LOADMATCH. The supplies from GATOR-GCMOM must be multiplied by the CAFs to be consistent with the new nameplate capacities used in LOADMATCH. Table S1 lists the countries in each region.

Table S13. Capacity Factors, Related to Star Methods.
Simulation-averaged 2050-2052 capacity factors (percentage of nameplate capacity produced as electricity before transmission, distribution, maintenance, storage, or curtailment losses) by region in the base case (Case I). The mean capacity factors in this table equal the simulation-averaged power output supplied by each generator in each region from Table S14 divided by the final nameplate capacity of each generator in each region from Table S11. Values in each region in Cases II-IV are the same as in Case I, except for slight differences in the CF of hydropower since hydropower's use varies during each simulation since it provides both electricity generation and storage. In addition, in Case IV, the overall weighted average for each generator differs for onshore and offshore wind and utility PV, relative to Cases I-III, because of the different nameplate capacities of generators used in Case IV versus Cases I-III.

Region	Onshore wind	Off-shore wind	Rooftop PV	Utility PV	CSP with storage	Geo-thermal elec-tricity	Hydropower	Wave	Tidal	Solar thermal	Geo-thermal heat
Africa	0.373	0.443	0.202	0.217	0.76	0.809	0.359	0.175	0.223	0.111	0.54
Australia	0.337	0.427	0.197	0.229	0.79	0.904	0.476	0.332	0.247	0.109	0.54
Canada	0.501	0.587	0.177	0.18	0	0.862	0.44	0.297	0.235	0.097	0.54
Central America	0.293	0.306	0.199	0.221	0.82	0.84	0.387	0.126	0.229	0.12	0.54
Central Asia	0.538	0.508	0.2	0.237	0.82	0	0.323	0.121	0.216	0	0.54
China region	0.471	0.372	0.2	0.221	0.73	0.896	0.497	0.139	0.243	0.109	0.54
Cuba	0.423	0.306	0.166	0.178	0.7	0	0.396	0.379	0.232	0	0
Europe	0.444	0.513	0.171	0.176	0.67	0.861	0.418	0.203	0.237	0.093	0.54
Haiti region	0.321	0.428	0.213	0.232	0.79	0.876	0.402	0	0.216	0	0
Iceland	0.573	0	0	0	0	0.925	0.551	0	0.253	0	0.54
India region	0.454	0.411	0.197	0.227	0.78	0.857	0.447	0.133	0.233	0.11	0.54
Israel	0.47	0.365	0.236	0.259	0.89	0	0.51	0	0.252	0.132	0.54
Jamaica	0.344	0.388	0.213	0.23	0.79	0	0.36	0	0.208	0	0
Japan	0.388	0.449	0.177	0.2	0	0.909	0.478	0.141	0.248	0.097	0.54
Mauritius	0.437	0.408	0.204	0.222	0.75	0	0.481	0.316	0.251	0.113	0
Mideast	0.49	0.492	0.221	0.251	0.86	0.798	0.452	0.135	0.233	0.113	0.54
New Zealand	0.506	0.563	0.177	0.197	0.65	0.885	0.471	0.353	0.242	0.097	0.54
Philippines	0.241	0.299	0.206	0.229	0.8	0.858	0.451	0.133	0.234	0	0.54
Russia region	0.478	0.579	0.173	0.197	0	0.863	0.357	0.256	0.236	0.095	0.54
South America	0.177	0.362	0.189	0.207	0.72	0.883	0.519	0.149	0.239	0.11	0.54
Southeast Asia	0.124	0.217	0.199	0.214	0.73	0.879	0.438	0.178	0.226	0.116	0.54
South Korea	0.366	0.352	0.179	0.193	0.63	0	0.483	0	0.251	0.097	0.54
Taiwan	0.266	0.345	0.182	0.196	0	0.927	0.488	0.144	0.255	0.1	0.54
United States	0.379	0.294	0.197	0.207	0.86	0.891	0.274	0.294	0.244	0.104	0.54
Average	0.395	0.34	0.196	0.217	0.76	0.887	0.447	0.182	0.239	0.108	0.54

Capacity factors of offshore and onshore wind turbines account for array losses (extraction of kinetic energy by turbines). In all cases, capacity factors are determined before transmission, distribution, maintenance, storage, or curtailment losses, which are summarized for each region in Tables S22-S24. T&D loss rates are given in Table S25. 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 [S13].

Table S14. LOADMATCH Power Supplied by Generation Technology, Related to Star Methods. LOADMATCH 2050-2052 base case (Case I) simulation-averaged all-sector projected WWS end-use power supplied (which equals power consumed plus power lost during transmission, distribution, maintenance, and curtailment), by region and percentage of such supply met by each generator. Simulation-average power supply (GW) equals the simulation total energy supply (GWh/simulation) 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 S13) to obtain the final 2050 nameplate capacity of each generator needed to meet the supply (Table S11). The 2050 total WWS supply is also obtained from Column (f) of Table S22.

Region	Annual-average total WWS supply (GW)	On-shore wind (%)	Off-shore wind (%)	Roof PV (%)	Utility PV (%)	CSP with stor-age (%)	Geoth ermal elec-tricity (%)	Hydro power (%)	Wave (%)	Tidal (%)	Solar ther-mal heat (%)	Geo-ther-mal heat (%)
Africa	614.2	31.85	10.96	32.28	18.97	3.43	0.476	1.843	0.100	0.030	0.048	0.017
Australia	124.2	22.54	6.61	16.36	47.42	3.07	0.291	2.852	0.154	0.099	0.564	0.041
Canada	201.9	54.40	10.71	10.19	3.86	0	2.134	17.809	0.139	0.233	0.031	0.490
Central America	262.7	46.27	10.82	12.57	21.18	2.50	3.420	2.928	0.115	0.028	0.138	0.034
Central Asia	263.4	49.98	4.09	21.27	19.04	2.47	0	3.055	0.076	0.002	0	0.001
China region	3,025	33.68	9.32	13.49	32.60	3.20	0.055	5.652	0.040	0.018	1.221	0.726
Cuba	16.1	46.30	9.17	20.30	21.78	2.10	0	0.168	0.120	0.068	0	0
Europe	1,266	42.26	18.42	11.39	19.56	0.85	0.217	5.488	0.077	0.105	0.289	1.351
Haiti region	10.8	15.78	11.59	22.14	39.56	2.77	5.522	2.519	0	0.105	0	0
Iceland	4.20	22.21	0	0	0	0	19.62	27.39	0	0.227	0	30.56
India region	1,207	25.14	3.68	23.66	39.48	6.03	0.020	1.818	0.054	0.017	0.086	0.016
Israel	23.2	6.77	8.53	15.78	64.41	2.39	0	0.015	0	0.009	1.902	0.192
Jamaica	3.52	3.49	35.55	32.39	24.61	3.53	0	0.307	0	0.120	0	0
Japan	235.6	1.78	57.94	2.81	31.28	0	0.563	4.540	0.160	0.232	0.106	0.590
Mauritius	2.51	1.74	54.75	5.62	34.89	1.20	0	1.168	0.159	0.065	0.420	0
Mideast	1,031	32.82	6.67	14.24	40.50	3.08	0.135	2.140	0.006	0.006	0.208	0.198
New Zealand	33.5	64.98	2.75	6.30	10.97	1.11	5.281	7.52	0.081	0.144	0.032	0.836
Philippines	63.1	9.15	9.64	22.72	45.72	2.03	7.799	2.647	0.119	0.186	0	0.001
Russia region	346.0	70.80	8.54	5.84	9.07	0	0.125	5.365	0.152	0.025	0.001	0.078
South America	548.9	48.67	6.25	12.97	11.14	3.03	0.861	16.61	0.132	0.052	0.233	0.061
Southeast Asia	841.7	0.80	40.62	25.26	26.93	2.48	1.437	2.347	0.093	0.017	0.002	0.010
South Korea	249.8	0.31	52.79	13.40	30.41	2.27	0	0.350	0	0.101	0.052	0.322
Taiwan	109.3	0.91	32.49	15.77	21.13	0	28.53	0.934	0.119	0.006	0.112	.00005
United States	1,370	45.32	8.10	8.37	33.05	2.05	0.424	1.580	0.145	0.006	0.136	0.817
All regions	**11,853**	**33.47**	**13.49**	**15.32**	**28.84**	**2.74**	**0.728**	**4.391**	**0.077**	**0.039**	**0.416**	**0.491**

Table S15. Energy Storage Capacities and Charge/Discharge Rates, Related to Star Methods. Aggregate (among all countries in each region) maximum instantaneous charge rates, maximum instantaneous discharge rates, maximum energy storage capacities, and hours of storage at the maximum discharge rate of the different types of electricity storage [PHS, CSP-PCM, batteries (BS), hydropower (CH), and grid hydrogen (green hydrogen storage-GHS)], cold storage (CW-STES, ICE), and heat storage (HW-STES, UTES) technologies treated here, by region, in the baseline case (Case I). Total hydropower ("Hydropower") is split into baseload ("Base") and peaking ("Peaking") hydropower, as described in Note S5. The maximum storage capacities are either of electricity for the electricity storage options or of thermal energy for the hot and cold storage options. The only changes to this table for Cases II-IV are the values for batteries and for grid H_2, which are given in Figures S2-S3 and Tables S18-S21. The last row for each region is the 2050 annual-average WWS all-sector demand from Table S8. Peak demand during a simulation exceeds annual-average demand, as illustrated for the same regions in Figures 3 and S2 of ref. [S19].

	Africa				**Australia**				**Canada**			
Storage technology	Max charge rate GW	Max discharge rate GW	Max storage capacity TWh	Hours storage at max discharge rate	Max charge rate GW	Max discharge rate GW	Max storage capacity TWh	Hours storage at max discharge rate	Max charge rate GW	Max discharge rate GW	Max storage capacity TWh	Hours storage at max discharge rate
PHS	27.8	27.8	0.39	14	10.7	10.7	0.150	14	0.8	0.8	0.011	14
CSP-elec.	27.7	27.7	--	--	4.86	4.86	--	--	0	0	--	--
CSP-PCM	44.7	--	0.6	22.6	7.84	--	0.110	22.6	0	--	0	0
Batteries	450	450	1.80	4	190	190	0.76	4	0	0	0	0
Hydropower	14.46	31.52	125.4	3,978	3.74	7.45	6.8	919	39.15	81.82	185.0	2,260
Base	10.82	10.82	93.5	8,640	3.54	3.54	5.1	1,440	21.59	21.59	31.1	1,440
Peaking	3.64	20.70	31.9	1,541	0.20	3.91	1.8	448	17.57	60.24	153.9	2,555
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	3.79	3.79	0.053	14	0.211	0.211	0.0029	14	0.248	0.248	0.0035	14
ICE	5.68	5.68	0.080	14	0.316	0.316	0.0044	14	0.372	0.372	0.0052	14
HW-STES	143.9	143.9	0.29	2	9.19	9.19	0.018	2	24.33	24.33	0.195	8
UTES-heat	2.85	143.95	86.4	600	6.55	9.19	0.221	24	2.47	24.33	1.168	48
UTES-elec.	129.6	--	--	--	9.19	--	--	--	14.60	--	--	--
Avg. demand		482.1				92.3				170.3		
	Central America				**Central Asia**				**China region**			
PHS	6.00	6.00	0.084	14	12.0	12.0	0.168	14	110.2	110.2	1.543	14
CSP-elec.	8.05	8.05	--	--	7.97	7.97	--	--	132.2	132.2	--	--
CSP-PCM	12.98	--	0.182	22.6	12.84	--	0.180	22.6	213.2	--	2.984	22.6
Batteries	790	790	3.16	4	130	130	0.52	4	1,690	1,690	6.76	4
Hydropower	9.14	19.86	23.9	1,205	11.28	24.96	40.4	1,619	170.8	343.7	250	729
Base	7.67	7.67	11.1	1,440	7.98	7.98	11.5	1,440	170.2	170.2	245	1,440
Peaking	1.47	12.18	12.9	1,057	3.30	16.97	28.9	1,704	0.6	173.5	5	31.4
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	0.672	0.672	0.0094	14	0.066	0.066	0.0009	14	11.63	11.63	0.1628	14
ICE	1.01	1.01	0.0141	14	0.099	0.099	0.0014	14	17.44	17.44	0.2442	14
HW-STES	27.69	27.69	0.055	2	27.02	27.02	0.216	8	558.2	558.2	1.675	3
UTES-heat	3.19	27.69	0.664	24	0.0029	27.02	5.837	216	378.2	558.2	147.4	264
UTES-elec.	2.77	--	--	--	8.11	--	--	--	558.2	--	--	--
Avg. demand		156.49				166.87				2,423.9		
	Cuba				**Europe**				**Haiti region**			
PHS	3.00	3.00	0.042	14	192.1	192.1	2.69	14	2.00	2.00	0.028	14
CSP-elec.	0.481	0.481	--	--	16.17	16.17	--	--	0.378	0.378	--	--
CSP-PCM	0.776	--	0.011	22.6	26.07	--	0.365	22.6	0.61	--	0.009	22.6
Batteries	95	95	0.380	4	830	830	3.32	4	22	22	0.088	4
Hydropower	0.032	0.068	0.084	1,236	81.47	166.3	211.9	1,274	0.324	0.676	0.85	1,254
Base	0.027	0.027	0.039	1,440	68.55	68.6	98.7	1,440	0.272	0.272	0.39	1,440
Peaking	0.005	0.041	0.045	1,101	12.92	97.7	113.2	1,158	0.052	0.404	0.46	1,130
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	0.101	0.101	0.0014	14	4.54	4.54	0.0636	14	0.033	0.033	.00046	14
ICE	0.152	0.152	0.0021	14	6.82	6.82	0.0954	14	0.049	0.049	.00069	14

HW-STES	1.67	1.67	0.013	8	311.1	311.1	1.867	6	4	4	0	0
UTES-heat	0	1.67	2.084	1,248	70.80	311.1	37.333	120	0	3.97	0.190	48
UTES-elec.	1.67	--	--	--	248.9	--	--	--	3.57	--	--	--
Avg. demand		8.99				958.29				7.60		
	Iceland				**India region**				**Israel**			
PHS	0	0	0	0	25.8	25.8	0.361	14	1.1	1.1	0.015	14
CSP-elec.	0	0	--	--	92.85	92.85	--	--	0.625	0.625	--	--
CSP-PCM	0	--	0	0	149.7	--	2.096	22.6	1.01	--	0.014	22.6
Batteries	0	0	0	0	4,100	4,100	16.40	4	240	240	0.960	4
Hydropower	1.07	2.09	2.8	1,337	23.18	49.08	42.4	865	0.0036	0.0070	0.0024	346
Base	0.76	0.76	0.1	120	21.94	21.94	31.6	1,440	0.0036	0.0036	0.0024	673
Peaking	0.31	1.32	2.7	2,040	1.24	27.14	10.9	400	0	0.0034	0	0
Grid H_2	0	0	0.0	0	0	0	0	0	0	0	0	0
CW-STES	0.018	0.018	.00025	14	4.67	4.67	0.0653	14	0.109	0.109	0.0015	14
ICE	0.027	0.027	.00037	14	7.00	7.00	0.0980	14	0.164	0.164	0.0023	14
HW-STES	1.05	1.05	0.0021	2	326.5	326.5	2.612	8	2.95	2.95	0.024	8
UTES-heat	0	0	0	0	9.82	326.5	101.87	312	3.43	2.95	2.481	840
UTES-elec.	0	--	--	--	326.5	--	--	--	2.36	--	--	--
Avg. demand		3.17				1,006.8				12.77		
	Jamaica				**Japan**				**Mauritius**			
PHS	0.10	0.10	0.001	14	96.7	96.7	1.35	14	0.1	0.1	0.001	14
CSP-elec.	0.157	0.157	--	--	0	0	--	--	0.040	0.040	--	--
CSP-PCM	0.254	--	0.0036	22.6	0	--	0	0.0	0.065	--	0.0009	22.6
Batteries	15	15	0.0600	4	410	410	1.64	4	10.5	10.5	0.0420	4
Hydropower	0.013	0.03	0.0337	1,122	11.30	22.38	20.7	924	0.031	0.061	0.057	931
Base	0.011	0.01	0.0155	1,440	10.69	10.69	15.4	1,440	0.029	0.029	0.042	1,440
Peaking	0.002	0.02	0.0181	944	0.60	11.69	5.3	453	0.002	0.032	0.015	460
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	0	0	0	0	0.149	0.149	0.0021	14	0.028	0.028	.00039	14
ICE	0	0	0	0	0.224	0.224	0.0031	14	0.042	0.042	.00059	14
HW-STES	0.92	0.92	0.0055	6	21.57	21.57	0.043	2	0.101	0.101	0.0002	2
UTES-heat	0	0.92	0.0665	72	5.15	21.57	1.035	48	0.093	0.101	0.0410	408
UTES-elec.	0.09	--	--	--	6.47	--	--	--	0.060	--	--	--
Avg. demand		2.56				186.33				1.89		
	Mideast				**New Zealand**				**Philippines**			
PHS	4.5	4.5	0.063	14	2.0	2.0	0.028	14	2.4	2.4	0.034	14
CSP-elec.	36.79	36.79	--	--	0.57	0.57	--	--	1.60	1.60	--	--
CSP-PCM	59.32	--	0.830	22.6	0.92	--	0.013	22.6	2.58	--	0.036	22.6
Batteries	1,500	1,500	6.00	4	14	14	0.056	4	311	311	1.244	4
Hydropower	22.07	48.85	15.0	307	2.63	5.35	4.8	900	1.76	3.70	3.2	873
Base	22.07	22.07	15.0	679	2.49	2.49	3.6	1,440	1.67	1.67	2.4	1,440
Peaking	0	26.78	0	0	0.14	2.86	1.2	430	0.09	2.03	0.8	407
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	1.16	1.16	0.0162	14	0.0043	0.0043	.00006	14	0.68	0.68	0.0095	14
ICE	1.74	1.74	0.0244	14	0.01	0.01	0.0001	14	1.02	1.02	0.0142	14
HW-STES	72.47	72.47	0.145	2	1.07	1.07	0.002	2	26.50	26.50	0.212	8
UTES-heat	22.84	72.47	57.394	792	0.63	1.07	0.026	24	0.00	26.50	8.269	312
UTES-elec.	72.5	--	--	--	0.11	--	--	--	5.30	--	--	--
Avg. demand		706.51				16.70				41.02		
	Russia region				**South America**				**Southeast Asia**			
PHS	10.8	10.8	0.152	14	19.5	19.5	0.273	14	3.5	3.5	0.049	14
CSP-elec.	0	0	--	--	23.13	23.13	--	--	28.66	28.66	--	--
CSP-PCM	0	--	0	0.0	37.29	--	0.522	22.6	46.22	--	0.647	22.6
Batteries	0	0	0	0	0	0	0.000	0	1,280	1,280	5.12	4
Hydropower	25.03	51.98	89.7	1,725	84.03	175.63	219.9	1,252	20.86	45.06	38.2	848
Base	17.71	17.71	25.5	1,440	61.45	61.45	22.1	360	19.74	19.74	28.4	1,440
Peaking	7.32	34.27	64.2	1,872	22.58	114.18	197.8	1,732	1.12	25.31	9.8	386
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	1.37	1.37	0.0191	14	2.93	2.93	0.0410	14	3.25	3.25	0.0455	14
ICE	2.05	2.05	0.0287	14	4.40	4.40	0.0616	14	4.87	4.87	0.0682	14
HW-STES	100.42	100.42	1.004	10	61.79	61.79	0.494	8	129.6	129.6	0.259	2
UTES-heat	0.52	100.42	12.05	120	12.21	61.79	1.483	24	0.264	129.6	6.222	48

UTES-elec.	10.04	--	--	--	6.18	--	--	--	64.8	--	--	--
Avg. demand		268.3				468.71				584.57		
	South Korea				**Taiwan**				**United States**			
PHS	16.5	16.5	0.23	14	9.1	9.1	0.127	14	80.0	80.0	1.12	14
CSP-elec.	9.07	9.07	--	--	0	0	--	--	32.85	32.85	--	--
CSP-PCM	14.63	--	0.205	22.6	0	--	0	0	52.97	--	0.742	22.6
Batteries	1,060	1,060	4.24	4	1,190	1,190	4.76	4	2,900	2,900	11.60	4
Hydropower	0.92	1.81	1.689	935	1.08	2.09	1.972	942	39.19	79.15	185.1	2,339
Base	0.87	0.87	1.257	1,440	1.02	1.02	1.468	1,440	21.61	21.61	31.1	1,440
Peaking	0.05	0.93	0.432	463	0.06	1.07	0.504	470	17.58	57.54	154.0	2,676
Grid H_2	0	0	0	0	0	0	0	0	0	0	0	0
CW-STES	0.149	0.149	0.0021	14	0.23	0.23	0.0033	14	2.97	2.97	0.0416	14
ICE	0.223	0.223	0.0031	14	0.35	0.35	0.0049	14	4.46	4.46	0.0624	14
HW-STES	18.28	18.28	0.037	2	20.45	20.45	0.041	2	167.6	167.6	0.335	2
UTES-heat	2.81	18.28	2.193	120	1.22	20.45	2.454	120	38.65	167.6	8.05	48
UTES-elec.	7.31	--	--	--	20.45	--	--	--	150.8	--	--	--
Avg. demand		154.38				89.91				959.46		
	All Regions											
PHS	637	637	8.91	14								
CSP-elec.	424	424	--	--								
CSP-PCM	684	--	9.58	22.6								
Batteries	17,228	17,228	68.91	4								
Hydropower	564	1,164	1,470	1,264								
Base	473	473	674	1,427								
Peaking	91	691	796	1,152								
Grid H_2	0	0	0	0								
CW-STES	39.0	39.0	0.546	14								
ICE	58.5	58.5	0.819	14								
HW-STES	2,058	2,058	9.54	5								
UTES-heat	564	2,058	484.87	236								
UTES-elec.	1,650	--	--	--								
Avg. demand		8969.9										

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

CSP-elec. is the production of electricity from CSP regardless of whether CSP storage exists. Heat captured in a working fluid by a CSP solar collector can be either 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 discharge rate of electricity from CSP generators is the summed nameplate capacity of the generators. The maximum charge rate of such electricity generators is limited to the maximum discharge rate.

CSP-PCM is the phase-change material storage associated with CSP. That storage is discharged for electricity production at the maximum discharge rate of CSP-elec. Thus, the maximum energy storage capacity of CSP-PCM equals the maximum electricity discharge rate of CSP-elec. multiplied by the maximum number of hours of storage at full discharge. The maximum charge rate of CSP phase-change material storage 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 (footnote to Table S25). The maximum number of hours of storage at full discharge is 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 (GW) in 2050 is its 2020 nameplate capacity, and its annual energy output (TWh/y) in 2050 is close to that in 2020 in every region. Water released from a dam during hydropower production is replenished naturally with rainfall and runoff. Hydropower reservoirs contain water for energy and non-energy purposes. About 50-60% of the water in a reservoir is generally used for energy [S20]. The hydropower storage capacity available for energy in all reservoirs worldwide is estimated as ~1,470 TWh, broken down as follows: North America: 370 TWh; China: 250 TWh; Latin America: 245 TWh; Europe: 215 TWh; Eurasia: 130 TWh; Africa: 125 TWh; Asia Pacific: 120 TWh; Middle East: 15 TWh (Figure 4.8 of ref. [S20]). The maximum hydropower storage capacity (TWh) in each country here is estimated by multiplying these regional storage capacities by the ratio of the 2020 hydroelectric energy output of the country to that of the region the country falls in. The maximum storage capacity in each of the 24 regions in this study is then calculated simply by summing the maximum storage capacities among all countries in the region. The maximum storage capacity, total nameplate capacity, and natural recharge rate (assumed to equal 2020 hydropower output) of hydropower generators in each region are then distributed between baseload and peaking power uses by solving a set of six equations and six unknowns: (1) the sum of the maximum energy storage capacities (TWh) for baseload and peaking power equals the total maximum energy storage capacity among all reservoirs in each region, as just determined; (2) the sum of the instantaneous average charge rates (TW) of power for baseload and peaking power equals the total average charge rate of the region's reservoirs, which equals the annual average hydropower power output (TW) of the reservoirs in 2020 (which equals the 2020 energy output in TWh/y divided by 8,760 hours per year); (3) the sum of the maximum discharge rates (TW) for each baseload and peaking power equals the total nameplate capacity of all hydropower generators in the region; (4) the maximum discharge rate (TW) of baseload power from generators equals the instantaneous average charge rate of baseload power; (5) the maximum energy storage capacity (TWh) for peaking power equals the instantaneous average charge rate of peaking power (TW) multiplied by 8,760 hours per year (in other words, the peaking portion of the reservoir must be filled once per year); and (6) the maximum energy storage capacity (TWh) for baseload power equals the instantaneous average charge rate of baseload power (TW multiplied by a designated number of hours of storage of baseload energy. Since the maximum discharge rate of baseload hydropower is assumed to equal its instantaneous average charge rate, there should be no need for baseload storage. However, in reality, discharged water for baseload power is not replenished immediately. As such, sufficient storage capacity is assigned to baseload hydropower so that, if full, baseload can supply 60 days (1,440 hours) straight of hydroelectricity without any replenishment. For Iceland and South America, 5 and 15 days, respectively, are assumed instead of 60 days. In sum, whereas baseload power is produced and discharged continuously in the model every 30 s, peaking power is also produced every 30 s but discharged only when needed due to a lack of other WWS resources available. Whereas the present table gives hydropower's maximum energy storage capacity available for each baseload and storage, hydropower's output from baseload or peaking storage during a time step is limited by the smallest among three factors in each case: the actual energy currently available in storage for baseload or peaking, the maximum hydro discharge rate for peaking or baseload multiplied by the time step, and (in the case of peaking) the energy needed during the time step to keep the grid stable. In addition, energy in the peaking portion of reservoirs is limited by the maximum storage capacity in that portion. Thus, if peaking energy is not used fast enough, it cannot accumulate due to rainfall and runoff to more than the maximum capacity.

Grid H_2. No grid hydrogen storage is included in Case I.

The CW-STES peak discharge rate is set equal to 40% of the annual-average cold demand (for air conditioning and refrigeration) subject to storage, which is given in Table S9 for each region. The ICE storage discharge rate is set to 60% of the same annual-average cold demand subject to storage. The peak charge rate is set equal to the peak discharge rate. Heat pumps are used to produce both cold water and ice. Table S27 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage.

The HW-STES peak discharge rate is set equal to the maximum instantaneous heat demand subject to storage during any 30-second period of the simulation. The values have been converted to electricity assuming the heat needed for storage is produced by heat pumps (with a coefficient of performance of 4) running on electricity. Table S27 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage. Because peak discharge rates are based on maximum rather than the annual-average demands, they are higher than the annual-average low-temperature heat demands subject to storage in Table S9. The peak charge rate is set equal to the peak discharge rate.

UTES heat stored in soil (borehole storage) or water pits can be charged with either solar or geothermal heat or excess electricity running an electric heat pump with 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 plus that of geothermal heat, all divided by the coefficient of performance of a heat pump (=4). When no solar thermal collectors or geothermal heat is used, 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 demand 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 demand 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. Table S27 (footnotes) provides the cost of the heat pumps per kW-electricity consumed to charge storage with electricity.

Table S16. Parameters Related to HVDC Transmission and District Heating, Related to Star Methods. (a) HVDC line length needed in each region; (b) HVDC line capacity needed in each region; (c) fraction of non-roof PV and non-curtailed energy that is subject to HVDC transmission in each region; and (d) the fraction of building heating and cooling demand that is subject to district heating and cooling in the baseline case. Values are the same for Cases I-IV.

Region	(a) HVDC line length (km)	(b) HVDC line capacity (MW)	(c) Fraction of non-roof PV/non-curtailed electricity subject to HVDC	(d) Fraction of building heating/ cooling subject to district heating/ cooling
Africa	2,999	193,216	0.3	0.1
Australia	2,837	47,600	0.3	0.1
Canada	3,221	98,791	0.3	0.2
Central America	2,275	56,236	0.2	0.1
Central Asia	2,420	74,835	0.3	0.01
China region	3,061	1,322,121	0.3	0.3
Cuba	0	0	0	0.2
Europe	2,891	544,403	0.3	0.5
Haiti region	0	0	0	0.05
Iceland	0	0	0	0.92
India region	3,187	474,069	0.3	0.1
Israel	0	0	0	0.2
Jamaica	0	0	0	0
Japan	3,020	78,962	0.2	0.1
Mauritius	0	0	0	0.2
Mideast	2,617	375,692	0.3	0.05
New Zealand	1,904	4,995	0.15	0.05
Philippines	2,484	12,484	0.2	0.2
Russia region	2,962	168,048	0.3	0.5
South America	3,261	258,065	0.3	0.1
Southeast Asia	2,652	253,876	0.3	0.1
South Korea	0	0	0	0.15
Taiwan	0	0	0	0.15
United States	2,675	569,666	0.3	0.2

The capital cost of HVDC transmission is the product of Columns (a), (b), and $400/MW-km [S17].

Table S17. Hydrogen and Battery Information, Related to Star Methods.

(a)-(d) hydrogen storage times for non-grid or grid plus non-grid hydrogen for each of the four cases treated here; (e)-(g) battery full cycles per year in Cases I-III (Case IV has no batteries); (h)-(j) the maximum battery discharge rate actually occurring during any time interval of the simulation in Cases I-III (Tables S18-S21 provide the peak discharge rate of batteries in each case); and (k)-(m) R_{ideal}, the number of hours of battery storage actually needed for each simulation, which equals the ratio of the battery storage capacity (TWh) from Tables S18-S21 or Figures S2-S3 for each case divided by the battery peak actual discharge rate (TW) during any time interval of the simulation, from Columns (h)-(j) of this table. The hydrogen storage time equals the non-grid or grid plus non-grid hydrogen storage tank size from Tables S18-S21 divided by the non-grid hydrogen production rate from Tables S18-S21, all multiplied by 365 days per year. It is the time required for hydrogen storage tanks used for non-grid (or grid plus non-grid) purposes to empty if the discharge rate of hydrogen from the storage equals the production rate of the non-grid hydrogen. The battery peak discharge rate occurring during a simulation is always less than or equal to the battery nameplate capacity (peak possible discharge rate) from Tables S18-S21. Case IV assumes no batteries. Also, no battery-related values are shown for some regions since these regions require no battery storage.

	Non-grid (Cases I and III) or grid plus non-grid (Case II) H_2 storage times (days)				Battery full cycles/year			Battery peak actual discharge rate during simulation (TW)			R_{ideal}=Ratio of battery storage capacity (TWh) to battery peak actual discharge rate (TW) during simulation (hours)		
Region	(a) Case I	(b) Case II	(c) Case III	(d) Case IV	(e) Case I	(f) Case II	(g) Case III	(h) Case I	(i) Case II	(j) Case III	(k) Case I	(l) Case II	(m) Case III
Africa	19.5	9	22	57	236	207	258	0.286	0.287	0.286	6.3	7.4	5.6
Australia	18	16	10	9	205	258	343	0.08	0.08	0.08	9.5	7.5	4.0
Canada	0	0	0	0	0	0	0	0	0	0	--	--	--
Central America	19	29	12	7	25	88	131	0.117	0.117	0.11	27.0	7.2	4.0
Central Asia	3.8	11	3	25	77	106	113	0.117	0.09	0.08	4.5	4.0	4.0
China region	12	30	15	35	199	261	233	1.32	1.25	1.32	5.1	4.0	4.0
Cuba	31	61	32	59	32	61	130	0.01	0.01	0.01	39.5	20.0	8.7
Europe	12.2	30	12.8	36	96	165	110	0.606	0.015	0.605	5.5	4.0	4.0
Haiti region	9	11	14	51	142	163	155	0.007	0.007	0.007	11.8	10.9	10.7
Iceland	0.55	0.55	0.55	0.55	0	0	0	0	0	0	--	--	--
India region	1	14	25	30	120	245	305	0.997	0.873	0.841	16.4	8.8	7.1
Israel	0	39.8	32	196	36	65	189	0.017	0.016	0.016	56.0	28.9	9.8
Jamaica	5	14.5	5	15	66	103	98	0.003	0.003	0.003	22.6	13.8	15.1
Japan	8	11.5	9	12	49	97	89	0.126	0.126	0.126	13.0	6.3	6.7
Mauritius	47	60	60	90	36	98	145	0.002	0.002	0.002	25.1	9.8	4.9
Mideast	7	11	7	21	102	159	227	0.491	0.491	0.491	12.2	7.8	5.1
New Zealand	2.7	6.5	3	7	36	78	75	0.014	0	0.001	4.1	4.0	4.0
Philippines	9	78	11	48	53	238	145	0.067	0.06	0.066	18.4	4.0	6.7
Russia region	7.4	7.4	7.4	7.4	0	0	0	0	0	0	--	--	--
South America	2	2	2	2	0	0	0	0	0	0	--	--	--
Southeast Asia	8	9	9	56	123	143	160	0.433	0.45	0.415	11.8	9.8	9.4
South Korea	15	31	15	49	24	94	106	0.141	0.148	0.14	30.1	7.0	6.3
Taiwan	41	60	55	58	20	75	65	0.082	0.081	0.081	58.1	14.4	16.9
United States	13.1	18	15	79	59	107	109	0.753	0.709	0.709	15.4	8.9	8.8

Table S18. More Battery and Hydrogen Information, Related to Star Methods.

Case I. (a) Battery maximum charge and discharge rate (nameplate capacity); (b) battery energy storage capacity (all batteries are 4-hour batteries); (c) annual hydrogen production for non-grid purposes; (d) electrolzyer plus compressor nameplate capacity (electrolyzers make up 88.03% of the total); (e) electrolyzer and compressor use factor averaged over each simulation; and (f) hydrogen storage tank size (for non-grid purposes) in Case I.

	Batteries		Non-grid H_2			
Region	(a) Battery maximum charge and discharge rate (GW)	(b) Battery capacity (TWh)	(c) H_2 produced (Tg-H_2/y)	(d) Electrolyzer plus compressor nameplate capacity (GW)	(e) Electrolyzer and compressor use factor (frac)	(f) H_2 tank size (Tg)
Africa	450	1.8	8.674	310.9	0.15	0.4634
Australia	190	0.76	1.761	63.13	0.15	0.0869
Canada	0	0	2.682	14.42	1.00	0
Central America	790	3.16	2.463	88.27	0.15	0.1282
Central Asia	130	0.52	2.582	92.54	0.15	0.0269
China region	1,690	6.76	68.59	2,458	0.15	2.2549
Cuba	95	0.38	0.067	2.41	0.15	0.0057
Europe	830	3.32	23.11	828.2	0.15	0.7723
Haiti region	22	0.088	0.136	4.88	0.15	0.0034
Iceland	0	0	0.025	0.78	0.18	0.0000
India region	4,100	16.4	19.65	704.4	0.15	0.0538
Israel	240	0.96	0.148	0.80	1.00	0.0000
Jamaica	15.0	0.06	0.062	2.22	0.15	0.0009
Japan	410	1.64	5.532	198.3	0.15	0.1213
Mauritius	10.5	0.042	0.069	2.46	0.15	0.0088
Middle East	1,500	6	14.13	506.4	0.15	0.2710
New Zealand	14	0.056	0.269	9.65	0.15	0.0020
Philippines	311	1.244	0.848	30.40	0.15	0.0209
Russia region	0	0	8.811	222.9	0.21	0.1786
South America	0	0	9.029	323.7	0.15	0.0495
Southeast Asia	1,280	5.12	13.14	471.0	0.15	0.2880
South Korea	1,060	4.24	4.203	150.7	0.15	0.1727
Taiwan	1,190	4.76	1.561	55.97	0.15	0.1754
United States	2,900	11.6	14.12	506.3	0.15	0.5069
All regions	**17,228**	**68.91**	**201.7**	**7,049**	**0.154**	**5.5915**

Table S19. More Battery and Hydrogen Information, Related to Star Methods.

Case II. (a) Battery maximum charge and discharge rate (nameplate capacity); (b) battery storage capacity (batteries are all 4-hour batteries); (c) annual hydrogen production for non-grid purposes; (d) annual hydrogen production for grid purposes; (e) electrolzyer plus compressor nameplate capacity (electrolyzers make up 88.03% of the total); (f) electrolyzer and compressor use factor, averaged over simulation; (g) size of communal hydrogen storage tank; (h) nameplate capacity of fuel cells used for producing grid electricity; (i) fuel cell use factor; (j) hours of electricity storage in the hydrogen tank if the stored hydrogen were used only for grid electricity at the peak discharge rate of the fuel cells; and (l) usable (non-waste) electricity storage capacity* in the communal hydrogen storage tank if hydrogen were used only for electricity. Canada, Iceland, Russia region, and South America require no battery storage; thus, no hydrogen is needed for grid electricity in those regions in Cases II-IV.

	Batteries		Non-grid plus grid hydrogen					Grid hydrogen			
Region	(a) Battery maximum charge and discharge rate (GW)	(b) Battery capacity (TWh)	(c) Non-grid H_2 produced ($Tg-H_2/y$)	(d) Grid H_2 produced ($Tg-H_2/y$)	(e) Electrolyzer plus compressor nameplate capacity (GW)	(f) Use factor of electrolyzer and compressor (frac)	(g) H_2 tank size (Tg)	(h) Fuel cell for grid electricity nameplate capacity (GW)	(i) Use factor of fuel cell (frac)	(j) Hours of electricity storage in H_2 tank if H_2 used only for electricity= k*1000/h	(k) Electricity storage capacity in H_2 tank if H_2 used only for electricity (TWh)
Africa	530	2.12	8.674	0.155	310.9	0.15	0.2139	40	0.009	113	4.5
Australia	150	0.6	1.761	0.042	63.13	0.15	0.0772	10	0.010	163	1.63
Canada	0	0	2.682	0.000	14.42	1.00	0.0000	0	0	0.0	0.00
Central America	210	0.84	2.463	0.060	88.27	0.15	0.1957	16	0.009	258	4.13
Central Asia	90	0.36	2.582	0.124	92.54	0.16	0.0778	20	0.015	82.2	1.64
China region	1,250	5	68.59	13.08	2,458	0.18	5.6372	500	0.063	238	119.1
Cuba	48	0.192	0.067	0.005	8.00	0.05	0.0113	8	0.001	29.7	0.24
Europe	15	0.06	23.11	12.201	828.2	0.23	1.8992	210	0.140	191	40.1
Haiti region	19	0.076	0.136	0.00006	4.88	0.15	0.0041	0.25	0.001	346	0.09
Iceland	0	0	0.025	0.000	0.78	0.18	0.0000	0	0	0.0	0
India region	1,930	7.72	19.652	0.134	704.4	0.15	0.7538	355	0.001	44.8	15.9
Israel	118	0.472	0.148	0.001	5.31	0.15	0.0161	5	0.001	68.2	0.34
Jamaica	9.0	0.036	0.062	0.001	2.22	0.15	0.0025	1.2	0.002	43	0.05
Japan	200	0.8	5.532	0.159	198.3	0.15	0.1743	40	0.010	92	3.68
Mauritius	4.0	0.016	0.069	0.002	2.80	0.14	0.0113	2.8	0.002	85.1	0.24
Middle East	960	3.84	14.13	0.194	506.4	0.15	0.4258	140	0.003	64	9.0
New Zealand	0.3	0.0012	0.269	0.037	9.65	0.17	0.0048	1	0.064	72.3	0.10
Philippines	60	0.24	0.848	0.406	44.00	0.15	0.1812	44	0.022	87.0	3.83
Russia region	0	0	8.811	0.000	222.9	0.21	0.1786	0	0	0.0	3.77
South America	0	0	9.029	0.000	323.7	0.15	0.0495	0	0	0.0	1.0
Southeast Asia	1,100	4.4	13.14	0.052	471.0	0.15	0.3240	130	0.001	53	6.84
South Korea	260	1.04	4.203	0.247	150.7	0.16	0.3570	100	0.006	75	7.54
Taiwan	290	1.16	1.561	0.027	55.97	0.15	0.2567	30	0.002	181	5.42
United States	1,580	6.32	14.12	0.188	506.3	0.15	0.6966	155	0.003	94.9	14.7
All regions	**8,823**	**35.29**	**201.66**	**27.11**	**7,073**	**0.174**	**11.5484**	**1,809**	**0.036**	**135**	**243.9**

*Usable electricity storage capacity equals hydrogen tank storage capacity from Column (f) multiplied by the higher heating value of hydrogen (39.39 $kWh/kg-H_2$) and by 0.536 (Table S26), which equals the product of the fuel cell efficiency (0.65), the latent heat loss efficiency (0.846), and the DC to AC conversion efficiency (0.975).

Table S20. More Battery and Hydrogen Information, Related to Star Methods.

Case III. (a) Battery maximum charge and discharge rate (nameplate capacity); (b) battery storage capacity (batteries are all 4-hour batteries); (c) annual hydrogen production for non-grid purposes; (d) electrolzyer plus compressor nameplate capacity for non-grid purposes (electrolyzers make up 88.03% of the total); (e) electrolyzer and compressor use factor, averaged over each simulation, for non-grid purposes; (f) hydrogen storage tank size for non-grid purposes; (g) annual hydrogen production for grid purposes; (h) nameplate capacity of electrolyzers and compressors used for producing hydrogen for grid electricity (set equal to the nameplate capacity of fuel cells used for producing grid electricity); (i) electrolyzer and compressor use factor for producing grid hydrogen, (j) fuel cell use factor for producing grid electricity, (k) storage tank size for hydrogen producing grid electricity, (l) hours of electricity storage in the hydrogen tank used for grid electricity at the peak discharge rate of the fuel, and (m) usable (non-waste) electricity storage capacity in hydrogen tanks for grid electricity in Case III. Usable electricity storage capacity equals hydrogen tank capacity multiplied by the higher heating value of hydrogen (39.39 kWh/kg-H_2), the fuel cell efficiency (0.65), the latent heat loss efficiency (0.846), and the DC to AC conversion efficiency (0.975)-Table S26.

	Batteries		Non-grid hydrogen				Grid hydrogen						
Region	(a) Battery maximum charge and discharge rate (GW)	(b) Battery storage capacity (TWh)	(c) H_2 produced (Tg-H_2/y)	(d) Electrolyzer plus compressor nameplate capacity (GW)	(e) Use factor of electrolyzer and compressor (frac)	(f) H_2 tank size (Tg)	(g) H_2 produced (Tg-H_2/y)	(h) Electrolyzer plus compressor nameplate capacity = fuel cell nameplate capacity (GW)	(i) Use factor of electrolyzer and compressor (frac)	(j) Use factor of fuel cell (frac)	(k) H_2 tank size (Tg)	(l) Hours of electricity stor-age in H_2 tank=m *1000/h	(m) Electricity storage capacity in H_2 tank (TWh)
Africa	400	1.6	8.674	310.92	0.15	0.5228	0.120	10	0.064	0.029	0.0024	5.0	0.05
Australia	80	0.32	1.761	63.13	0.15	0.0483	1.996	38	0.282	0.125	0.2707	150	5.72
Canada	0	0	2.682	14.42	1.00	0	0	0	0	0	0	0	0
Central America	110	0.44	2.463	88.27	0.15	0.0810	0.640	38	0.091	0.040	0.2166	120	4.57
Central Asia	80	0.32	2.582	92.54	0.15	0.0212	0.128	17	0.041	0.018	0.0315	39.12	0.665
China region	1,320	5.28	68.59	2,458	0.15	2.8186	2.093	150	0.075	0.034	0.0285	4	0.60
Cuba	21	0.084	0.067	2.41	0.15	0.0059	0.038	5	0.041	0.018	0.0321	135	0.68
Europe	605	2.42	23.11	828.22	0.15	0.8103	0.454	30	0.081	0.036	0.0342	24	0.72
Haiti region	20	0.08	0.136	4.88	0.15	0.0052	0.000	1	0.001	0.000	0.0002	5	0.01
Iceland	0	0	0.025	0.78	0.18	0.0000	0	0	0	0	0	0	0
India region	1,500	6	19.65	704.42	0.15	1.3461	2.038	355	0.031	0.014	0.5901	35.1	12.46
Israel	40	0.16	0.148	5.31	0.15	0.0130	0.018	9	0.011	0.006	0.0209	49.1	0.44
Jamaica	10.0	0.04	0.062	2.22	0.15	0.0009	0.001	1.1	0.005	0.002	0.0010	20	0.022
Japan	210	0.84	5.532	198.29	0.15	0.1364	0.085	20	0.023	0.010	0.0333	35.1	0.70
Mauritius	2.0	0.008	0.069	2.46	0.15	0.0113	0.017	1.0	0.089	0.040	0.0059	125.4	0.1254
Middle East	630	2.52	14.13	506.40	0.15	0.2710	1.304	120	0.058	0.026	0.2280	40.1	4.81
New Zealand	0.6	0.0024	0.269	9.65	0.15	0.0022	0.028	1	0.135	0.061	0.0015	29.2	0.03
Philippines	110	0.44	0.848	30.40	0.15	0.0256	0.087	41	0.011	0.005	0.0487	25.1	1.03
Russia region	0	0	8.811	222.9	0.21	0.1786	0	0	0	0	0	0	0
South America	0	0	9.029	323.7	0.15	0.0495	0	0	0	0	0	0	0
Southeast Asia	970	3.88	13.14	471.01	0.15	0.3240	0.070	80	0.005	0.002	0.0266	7	0.56
South Korea	220	0.88	4.203	150.67	0.15	0.1727	0.365	80	0.025	0.011	0.1900	50	4.01
Taiwan	340	1.36	1.561	55.97	0.15	0.2353	0.060	28	0.012	0.005	0.0798	60.2	1.69
United States	1,550	6.2	14.12	506.28	0.15	0.5805	0.120	91	0.007	0.003	0.0562	13.0	1.19
All regions	**8,219**	**32.87**	**201.7**	**7,054**	**0.154**	**7.6627**	**9.66**	**1,116**	**0.047**	**0.021**	**1.8981**	**35.9**	**40.09**

Table S21. More Battery and Hydrogen Information, Related to Star Methods.

Case IV. (a) Battery maximum charge rate and discharge rate (nameplate capacity); (b) battery storage capacity (batteries are all 4-hour batteries); (c) annual hydrogen production for non-grid purposes; (d) annual hydrogen production for grid purposes; (e) electrolzyer plus compressor nameplate capacity (electrolyzers make up 88.03% of the total); (f) electrolyzer and compressor use factor, averaged over simulation; (g) size of communal hydrogen storage tank; (h) nameplate capacity of fuel cells used for producing grid electricity; (i) fuel cell use factor; (j) hours of electricity storage in the hydrogen tank if the stored hydrogen were used only for grid electricity at the peak discharge rate of the fuel cells; and (l) usable (non-waste) electricity storage capacity in the communal hydrogen storage tank in Case IV. [Usable electricity storage capacity equals tank storage capacity multiplied by the higher heating value of hydrogen (39.39 kWh/kg-H_2), the fuel cell efficiency (0.65), the latent heat loss efficiency (0.846), and to DC to AC conversion efficiency (0.975)-Table S26.

	Batteries		Non-grid plus grid H_2					Grid H_2			
Region	(a) Battery maximum charge and discharge rate (GW)	(b) Battery capacity (TWh)	(c) Non-grid H_2 produced (Tg-H_2/y)	(d) Grid H_2 produced (Tg-H_2/y)	(e) Electrolyzer plus compressor nameplate capacity (GW)	(f) Use factor of electrolyzer and compressor (frac)	(g) H_2 tank size (Tg)	(h) Fuel cell for grid electricity nameplate capacity (GW)	(i) Use fac-tor of fuel cell (frac)	(j) Hours of electricity storage in H_2 tank if H_2 used only for electricity= k*1000/h	(k) Electricity storage capacity in H_2 tank if H_2 used only for electricity (TWh)
Africa	0	0	8.674	13.46	420	0.28	1.355	420	0.077	68.1	28.61
Australia	0	0	1.761	1.327	78	0.21	0.043	78	0.041	11.8	0.92
Canada	0	0	2.682	0	14.42	1.00	0	0	0	0	0
Central America	0	0	2.463	0.662	88.3	0.19	0.047	16	0.099	62.3	1.00
Central Asia	0	0	2.582	1.552	92.54	0.24	0.177	36	0.104	103.7	3.73
China region	0	0	68.59	52.22	2,458	0.26	6.577	650	0.193	214	138.9
Cuba	0	0	0.067	0.260	20	0.09	0.011	20	0.031	11.5	0.23
Europe	0	0	23.11	13.11	828.2	0.24	2.279	225	0.140	214	48.1
Haiti region	0	0	0.136	0.260	15	0.14	0.019	15	0.042	26.8	0.40
Iceland	0	0	0.025	0	0.78	0.18	0	0	0	0	0
India region	0	0	19.65	41.29	1,200	0.27	1.615	1,200	0.083	28.4	34.1
Israel	0	0	0.148	1.216	35	0.21	0.079	35	0.083	48.0	1.68
Jamaica	0	0	0.062	0.146	6	0.19	0.0025	6	0.059	8.9	0.054
Japan	0	0	5.532	3.149	198.3	0.24	0.182	50	0.151	76.8	3.84
Mauritius	0	0	0.069	0.056	3	0.22	0.0169	3	0.045	119.1	0.357
Middle East	0	0	14.13	16.94	506.4	0.33	0.813	210	0.194	81.7	17.2
New Zealand	0	0	0.269	0.045	9.65	0.18	0.0052	1.7	0.064	64.1	0.109
Philippines	0	0	0.848	2.880	100	0.20	0.112	100	0.069	23.6	2.36
Russia region	0	0	8.811	0	222.9	0.21	0.1786	0	0	0	0
South America	0	0	9.029	0	323.7	0.15	0.0495	0	0	0	0
Southeast Asia	0	0	13.14	27.41	980.0	0.22	2.016	980	0.067	43.4	42.6
South Korea	0	0	4.203	3.747	170	0.25	0.564	170	0.053	70	11.92
Taiwan	0	0	1.561	3.014	160	0.15	0.248	160	0.045	32.7	5.24
United States	0	0	14.12	20.64	800	0.23	3.057	800	0.062	80.7	64.6
All regions	**0**	**0**	**201.7**	**203.4**	**8,731**	**0.249**	**19.45**	**5,176**	**0.094**	**79.4**	**410.7**

Table S22. Summary LOADMATCH Energy Budget by Region, Related to Star Methods.
Budget of simulation-averaged end-use power demand met, energy lost, WWS energy supplied, and changes in storage, during the three-year (26,291.4875 hour) simulations for each region and summed for all regions in the base case (Case I). All units are GW averaged over the simulation and are derived from the data in Tables S23-S24 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.

Region	(a) Annual-average end-use demand (GW)	(b) TD&M losses (GW)	(c) Storage losses (GW)	(d) Curtail-ment losses (GW)	**(e) End-use demand + 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)**
Africa	482.15	34.16	19.18	79.77	**615.3**	614.2	1.057	**615.3**
Australia	92.28	8.07	2.66	21.24	**124.3**	124.3	-0.013	**124.3**
Canada	170.28	13.91	2.14	15.61	**201.9**	201.9	0.001	**201.9**
Central America	156.49	17.71	2.14	86.38	**262.7**	262.8	-0.039	**262.7**
Central Asia	166.87	16.40	2.60	77.55	**263.4**	263.4	-0.031	**263.4**
China region	2,423.9	200.72	74.60	329.79	**3,029**	3024.9	4.025	**3,029**
Cuba	8.99	1.01	0.37	5.69	**16.06**	16.1	-0.011	**16.06**
Europe	958.29	86.14	30.33	191.01	**1,265.8**	1266.1	-0.312	**1,265.8**
Haiti region	7.60	0.67	0.41	2.12	**10.79**	10.79	-0.002	**10.79**
Iceland	3.17	0.31	0.00	0.71	**4.20**	4.20	0.000	**4.20**
India region	1,006.8	73.33	40.38	88.32	**1,208.9**	1,206.9	1.963	**1,208.9**
Israel	12.77	1.50	0.70	8.28	**23.26**	23.17	0.086	**23.26**
Jamaica	2.56	0.20	0.06	0.72	**3.53**	3.52	0.002	**3.53**
Japan	186.33	17.27	2.72	29.33	**235.64**	235.65	-0.007	**235.64**
Mauritius	1.89	0.18	0.04	0.40	**2.52**	2.51	0.005	**2.52**
Mideast	706.51	68.45	17.76	239.96	**1,032.7**	1,031.4	1.227	**1,032.7**
New Zealand	16.70	2.39	0.07	14.35	**33.51**	33.5	-0.001	**33.51**
Philippines	41.02	3.87	1.98	16.35	**63.22**	63.1	0.152	**63.22**
Russia region	268.30	24.74	9.37	43.89	**346.30**	346.1	0.235	**346.30**
South America	468.71	36.85	4.61	38.90	**549.07**	549.0	0.063	**549.07**
Southeast Asia	584.57	50.39	14.10	192.88	**841.94**	842.0	-0.075	**841.94**
South Korea	154.38	16.72	3.31	75.41	**249.83**	249.9	-0.025	**249.83**
Taiwan	89.91	7.16	2.62	9.57	**109.25**	109.3	-0.033	**109.25**
United States	959.46	95.79	21.59	293.12	**1,370.0**	1,370.1	-0.115	**1,370.0**
All regions	8,969.9	777.9	253.7	1,861.4	**11,863**	11,855	8.151	**11,863**

Table S23. Detailed LOADMATCH Energy Budgets, Related to STAR Methods.
Budget of total end-use energy demand met, energy lost, WWS energy supplied, and changes in storage, during the three-year (26,291.4875 hour) LOADMATCH simulation for each region and summed over all regions, in the base case (Case I). 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 S22 for key parameters. Results are shown for alphabetically for region names starting with A-M.

	Africa	Australia	Canada	Central America	Central Asia
A1. Total end use demand	**12,676**	**2,426**	**4,477**	**4,114**	**4,387**
Electricity for electricity inflexible demand	6,276	1,286	2,313	1,936	2,350
Electricity for electricity, heat, cold storage + DR	5,175	891	1,785	1,830	1,672
Electricity for H_2 direct use + H_2 storage	1,226	249	379	348	365
A2. Total end use demand	**12,676**	**2,426**	**4,477**	**4,114**	**4,387**
Electricity for direct use, electricity storage, + H_2	11,794	2,373	4,245	3,960	4,188
Low-T heat demand met by heat storage	806	51	230	140	198
Cold demand met by cold storage	76.22	2.57	2.10	13.88	1.53
A3. Total end use demand	**12,676**	**2,426**	**4,477**	**4,114**	**4,387**
Electricity for direct use, electricity storage, DR	10,395	2,088	3,826	3,582	3,818
Electricity for H_2 direct use + H_2 storage	1,226	249	379	348	365
Electricity + heat for heat subject to storage	806	76	255	140	200
Electricity for cold demand subject to storage	248.96	13.84	16.28	44.16	4.34
B. Total losses	**3,500**	**841**	**832**	**2,793**	**2,538**
Transmission, distribution, downtime losses	898	212	366	466	431
Losses CSP storage	3.55	1	0.00	0.42	0.37
Losses PHS storage	4.01	0.0696	0.7337	0.0198	0.2430
Losses battery storage	142	51.8	0.00	26.0	13.3
Losses grid H_2 storage	0	0	0	0	0
Losses CW-STES + ICE storage	14	0.5	0.38	2.5	0.3
Losses HW-STES storage	97	4.6	37	26.7	35.7
Losses UTES storage	244	12.5	18	0.7	18.5
Losses from curtailment	2,097	558	410	2,271	2,039
Net end-use demand plus losses (A1 + B)	***16,176***	***3,267***	***5,309***	***6,907***	***6,926***
C. Total WWS supply before T&D losses	**16,148**	**3,267**	**5,309**	**6,908**	**6,926**
Onshore + offshore wind electricity	6,912	952	3,457	3,944	3,746
Rooftop + utility PV+ CSP electricity	8,830	2,184	746	2,504	2,964
Hydropower electricity	297.7	93.2	945.6	202.3	211.7
Wave electricity	16.16	5.03	7.37	7.94	5.23
Geothermal electricity	76.7854	9.5047	113.2666	236.2056	0
Tidal electricity	4.8689	3.2488	12.387	1.961	0.117
Solar heat	7.7406	18.4275	1.6265	9.5528	0
Geothermal heat	2.7599	1.3416	26.0254	2.3516	0.0416
D. Net taken from (+) or added to (-) storage	**27.7771**	**-0.3483**	**0.0327**	**-1.0207**	**-0.8189**
CSP storage	0.1312	0.0155	0	-0.0182	-0.018
PHS storage	-0.0389	-0.0374	-0.0011	-0.0084	-0.0168
Battery storage	0.7128	-0.0096	0	-0.316	-0.052
Grid H_2 storage	0	0	0	0	0
CW-STES+ICE storage	0.1193	0.0055	-0.0009	-0.0024	-0.0002
HW-STES storage	0.2591	-0.0046	0.0742	-0.0055	-0.0216
UTES storage	22.624	-0.0551	-0.0394	-0.0664	-0.5837
Non-grid H_2 storage	3.9696	-0.2626	0	-0.6037	-0.1266
Energy supplied plus taken from storage (C+D)	***16,176***	***3,267***	***5,309***	***6,907***	***6,926***

	China region	Cuba	Europe	Haiti region	Iceland
A1. Total end use demand	**63,727**	**236**	**25,194.9**	**200**	**83**
Electricity for electricity inflexible demand	29,891	119	11,478.9	100	31
Electricity for electricity, heat, cold storage + DR	24,141	108	10,449.7	81	49
Electricity for H_2 direct use + H_2 storage	9,695	10	3,266.3	19	4
A2. Total end use demand	**63,727**	**236**	**25,194.9**	**200**	**83**
Electricity for direct use, electricity storage, + H_2	59,214	224	21,808.7	191	69
Low-T heat demand met by heat storage	4,368	10	3,343.8	8	15
Cold demand met by cold storage	145.19	2.21	42.38	0.59	0.00
A3. Total end use demand	**63,727**	**236**	**25,194.9**	**200**	**83**
Electricity for direct use, electricity storage, DR	48,744	210	18,242.4	170	65
Electricity for H_2 direct use + H_2 storage	9,695	10	3,266.3	19	4
Electricity + heat for heat subject to storage	4,523	11	3,387.5	8	15
Electricity for cold demand subject to storage	764.42	6.67	298.66	2.14	0.00
B. Total losses	**15,909**	**186**	**8,084**	**84**	**27**
Transmission, distribution, downtime losses	5,277	27	2,264.79	18	8
Losses CSP storage	15.01	0.03	0.6641	0.04	0.00
Losses PHS storage	14.7856	0.0040	13	0.0005	0.0000
Losses battery storage	447	3.99	107	4.2	0.00
Losses grid H_2 storage	0	0	0	0	0
Losses CW-STES + ICE storage	26	0.40	8	0.1	0.00
Losses HW-STES storage	397	1.08	555	0.0	0.00
Losses UTES storage	1,061	4.15	115	6.3	0.00
Losses from curtailment	8,671	150	5,022.0	55.8	18.7
Net end-use demand plus losses (A1 + B)	***79,636***	***422***	***33,279.2***	***283.8***	***110.4***
C. Total WWS supply before T&D losses	**79,530**	**423**	**33,287.4**	**284**	**110**
Onshore + offshore wind electricity	34,193	234	20,197.9	78	25
Rooftop + utility PV+ CSP electricity	39,204	187	10,584.1	183	0
Hydropower electricity	4,494.7	0.7	1,826.7	7.1	30.2
Wave electricity	31.78	0.51	25.74	0.00	0.00
Geothermal electricity	43.8315	0	72.13	15.6697	21.6528
Tidal electricity	13.888	0.287	34.819	0.298	0.250
Solar heat	971.8804	0	96.332	0	0
Geothermal heat	577.4566	0	449.6054	0	33.7242
D. Net taken from (+) or added to (-) storage	**105.8262**	**-0.2803**	**-8.2109**	**-0.0459**	**-0.0015**
CSP storage	1.4128	-0.0011	-0.0365	-0.0008	0
PHS storage	-0.1543	-0.0042	-0.2689	-0.0028	0
Battery storage	1.8421	-0.038	-0.332	-0.0088	0
Grid H_2 storage	0	0	0	0	0
CW-STES+ICE storage	-0.0275	-0.0004	-0.0159	-0.0001	-0.0003
HW-STES storage	1.5072	-0.0013	-0.1867	0	-0.001
UTES storage	106.5653	-0.2084	-3.7333	-0.0188	0
Non-grid H_2 storage	-5.3195	-0.0269	-3.6376	-0.0146	-0.0002
Energy supplied plus taken from storage (C+D)	***79,636***	***422***	***33,279.2***	***283.8***	***110.4***

	India region	Israel	Jamaica	Japan	Mauritius
A1. Total end use demand	**26,471**	**336**	**67**	**4,899**	**50**
Electricity for electricity inflexible demand	12,686	183	29	2,708	18
Electricity for electricity, heat, cold storage + DR	11,007	132	29	1,409	22
Electricity for H_2 direct use + H_2 storage	2,778	21	9	782	10
A2. Total end use demand	**26,471**	**336**	**67**	**4,899**	**50**
Electricity for direct use, electricity storage, + H_2	25,442	317	66	4,723	47
Low-T heat demand met by heat storage	981	18	1	174	2
Cold demand met by cold storage	48.23	1.27	0.00	1.84	0.72

A3. Total end use demand	**26,471**	**336**	**67**	**4,899**	**50**
Electricity for direct use, electricity storage, DR	22,278	289	58	3,919	36
Electricity for H_2 direct use + H_2 storage	2,778	21	9	782	10
Electricity + heat for heat subject to storage	1,108	19	1	188	2
Electricity for cold demand subject to storage	306.75	7.17	0.00	9.81	1.84
B. Total losses	**5,312**	**276**	**26**	**1,296**	**17**
Transmission, distribution, downtime losses	1,928	39	5	454	5
Losses CSP storage	13.19	0.08	0.02	0.00	0.00
Losses PHS storage	0.0021	0.00	0.00	0.96	0.00
Losses battery storage	655	12	1	27	1
Losses grid H_2 storage	0	0	0	0	0
Losses CW-STES + ICE storage	8.71	0.23	0.00	0.33	0.13
Losses HW-STES storage	122.27	1	0	23	0
Losses UTES storage	262.87	6	0	21	0
Losses from curtailment	2,322	218	19	771	11
Net end-use demand plus losses (A1 + B)	***31,783***	***612***	***93***	***6,195***	***66***
C. Total WWS supply before T&D losses	**31,731**	**609**	**93**	**6,196**	**66**
Onshore + offshore wind electricity	9,145	93	36	3,700	37
Rooftop + utility PV+ CSP electricity	21,948	503	56	2,112	28
Hydropower electricity	576.8	0	0	281	1
Wave electricity	17.23	0	0	10	0
Geothermal electricity	6.31	0	0	34.8924	0
Tidal electricity	5.36	0.057	0.111	14.374	0.043
Solar heat	27	11.5871	0	6.5945	0.2775
Geothermal heat	5	1.171	0	36.5304	0
D. Net taken from (+) or added to (-) storage	**51.6027**	**2.2621**	**0.0427**	**-0.188**	**0.1371**
CSP storage	0.9574	0.0127	-0.0004	0	0.0003
PHS storage	-0.018	-0.0015	-0.0001	-0.1354	-0.0001
Battery storage	3.4206	0.2587	-0.006	-0.065	0.0074
Grid H_2 storage	0	0	0	0	0
CW-STES+ICE storage	0.001	0.0034	0	-0.0003	0.0009
HW-STES storage	2	0.0213	-0.0006	0.0388	0.0002
UTES storage	43.6624	1.9675	0.0537	0.0755	0.0369
Non-grid H_2 storage	1.0979	0	-0.0039	-0.1016	0.0916
Energy supplied plus taken from storage (C+D)	***31,783***	***612***	***93***	***6,195***	***66***

End-use demands in A1, A2, A3 should be identical. Transmission/distribution/maintenance loss rates are given in Table S25. Round-trip storage efficiencies are given in Table S27. Electricity production is curtailed 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 S24. Detailed LOADMATCH Energy Budgets, Related to STAR Methods.
Same as Table S23, but alphabetically for regions alphabetically M-Z, plus for all regions combined.

	Mideast	New Zealand	Philip-pines	Russia region	South America
A1. Total end use demand	**18,575**	**439**	**1,078**	**7,054**	**12,323**
Electricity for electricity inflexible demand	9,064	231	498	2,965	5,942
Electricity for electricity, heat, cold storage + DR	7,514	170	460	2,844	5,104
Electricity for H_2 direct use + H_2 storage	1,997	38	120	1,246	1,276
A2. Total end use demand	**18,575**	**439**	**1,078**	**7,054**	**12,323**
Electricity for direct use, electricity storage, + H_2	17,980	428	993	5,950	11,906
Low-T heat demand met by heat storage	577	11	72	1,082	334
Cold demand met by cold storage	18.18	0.06	13.12	21.95	83.63
A3. Total end use demand	**18,575**	**439**	**1,078**	**7,054**	**12,323**
Electricity for direct use, electricity storage, DR	15,912	390	841	4,615	10,511
Electricity for H_2 direct use + H_2 storage	1,997	38	120	1,246	1,276
Electricity + heat for heat subject to storage	590	11	73	1,104	344
Electricity for cold demand subject to storage	76.29	0.29	44.51	89.79	192.72
B. Total losses	**8,575**	**442**	**584**	**2,051**	**2,113**
Transmission, distribution, downtime losses	1,800	63	102	651	969
Losses CSP storage	4.34	0.01	0.19	0.00	2.19
Losses PHS storage	0.01	0.12	0.00	2.84	37.36
Losses battery storage	203	1	22	0	0
Losses grid H_2 storage	0	0	0	0	0
Losses CW-STES + ICE storage	3.29	0.01	2.37	3.97	15.10
Losses HW-STES storage	44	1	10	213	59
Losses UTES storage	211	0	18	27	8
Losses from curtailment	6,309	377	430	1,154	1,023
Net end-use demand plus losses (A1 + B)	***27,150***	***881***	***1,662***	***9,105***	***14,436***
C. Total WWS supply before T&D losses	**27,118**	**881**	**1,658**	**9,098**	**14,434**
Onshore + offshore wind electricity	10,708	597	311	7,219	7,929
Rooftop + utility PV+ CSP electricity	15,680	162	1,168	1,357	3,915
Hydropower electricity	580	66	44	488	2,397
Wave electricity	2	1	2	14	19
Geothermal electricity	36.558	46.5203	129.3001	11.3466	124.2522
Tidal electricity	1.737	1.271	3.084	2.234	7.470
Solar heat	56.4519	0.2852	0	0.0448	33.6144
Geothermal heat	53.6542	7.3616	0.0237	7.1371	8.8217
D. Net taken from (+) or added to (-) storage	**32.2489**	**-0.0218**	**3.9953**	**6.1898**	**1.6461**
CSP storage	0.5598	-0.0013	0.0216	0	0.2063
PHS storage	-0.0063	-0.0028	-0.0017	-0.038	0.2103
Battery storage	0.5847	-0.0056	0.15	0	0
Grid H_2 storage	0	0	0	0	0
CW-STES+ICE storage	-0.0029	0.0001	0.0216	-0.012	0.0924
HW-STES storage	0.1304	-0.0002	0.2014	-0.2511	-0.0487
UTES storage	31.4724	-0.0026	3.6269	6.4146	-0.1483
Non-grid H_2 storage	-0.4894	-0.0094	-0.0246	0.0763	1.3341
Energy supplied plus taken from storage (C+D)	***27,150***	***881***	***1,662***	***9,105***	***14,436***

	Southeast Asia	South Korea	Taiwan	United States	All regions
A1. Total end use demand	**15,369**	**4,059**	**2,364**	**25,226**	**235,833**
Electricity for electricity inflexible demand	6,902	2,162	1,157	12,895	113,222
Electricity for electricity, heat, cold storage + DR	6,609	1,303	986	10,334	94,104
Electricity for H_2 direct use + H_2 storage	1,858	594	221	1,997	28,507
A2. Total end use demand	**15,369**	**4,059**	**2,364**	**25,226**	**235,833**
Electricity for direct use, electricity storage, + H_2	14,806	3,883	2,256	23,810	220,675
Low-T heat demand met by heat storage	488	174	106	1,386	14,574
Cold demand met by cold storage	75.91	1.92	1.47	28.96	584
A3. Total end use demand	**15,369**	**4,059**	**2,364**	**25,226**	**235,833**
Electricity for direct use, electricity storage, DR	12,790	3,276	2,017	21,629	189,701
Electricity for H_2 direct use + H_2 storage	1,858	594	221	1,997	28,507
Electricity + heat for heat subject to storage	508	179	111	1,405	15,063
Electricity for cold demand subject to storage	213.52	9.79	15.29	195.23	2,562
B. Total losses	**6,767**	**2,509**	**509**	**10,793**	**76,062**
Transmission, distribution, downtime losses	1,325	440	188	2,518	20,452
Losses CSP storage	2.89	0.64	0.00	2.15	46
Losses PHS storage	0.01	0.02	0.03	0.30	75
Losses battery storage	209	34	31	228	2,216
Losses grid H_2 storage	0	0	0	0	0
Losses CW-STES + ICE storage	13.71	0.35	0.27	5.23	105
Losses HW-STES storage	83	24	15	194	1,944
Losses UTES storage	62	28	22	138	2,284
Losses from curtailment	5,071	1,983	252	7,707	48,938
Net end-use demand plus losses (A1 + B)	***22,136***	***6,568***	***2,872***	***36,018***	*311,895*
C. Total WWS supply before T&D losses	**22,138**	**6,569**	**2,873**	**36,021**	**311,680**
Onshore + offshore wind electricity	9,171	3,488	960	19,239	146,371
Rooftop + utility PV+ CSP electricity	12,102	3,027	1,060	15,663	146,168
Hydropower electricity	519	23	27	569	13,683
Wave electricity	21	0	3	52	240
Geothermal electricity	318.0787	0	819.6151	152.826	2,269
Tidal electricity	3.780	6.608	0.179	2.243	121
Solar heat	0.3349	3.3858	3.2135	49.065	1,298
Geothermal heat	2.1889	21.1719	0.0014	294.3594	1,531
D. Net taken from (+) or added to (-) storage	**-1.977**	**-0.6605**	**-0.8698**	**-3.019**	**214**
CSP storage	-0.0323	0.0984	0	-0.0741	3.2333
PHS storage	-0.0024	-0.023	-0.0064	-0.112	-0.6702
Battery storage	-0.256	-0.3491	-0.2037	-1.0138	4.3207
Grid H_2 storage	0	0	0	0	0.0000
CW-STES+ICE storage	-0.0057	-0.0002	-0.0001	-0.0101	0.1652
HW-STES storage	-0.013	0.0329	0.0389	0.0908	4.3423
UTES storage	-0.3111	0.0507	0.0049	0.3128	211.7005
Non-grid H_2 storage	-1.3565	-0.4701	-0.7034	-2.2126	-8.7937
Energy supplied plus taken from storage (C+D)	***22,136***	***6,568***	***2,872***	***36,018***	***311,895***

Table S25. Parameters for Determining the Cost of Energy, Related to STAR Methods.
Parameters for determining costs of energy from electricity and heat generators.

	Capital cost new installations ($million/MW)	O&M Cost ($/kW/y)	Decom-missioning cost (% of capital cost)	Lifetime (years)	TDM losses (% of energy generated)
Onshore wind electricity	1.01 (0.84-1.18)	37.5 (35-40)	1.25 (1.2-1.3)	30 (25-35)	7.5 (5-10)
Offshore wind electricity	2.34 (1.87-2.80)	80 (60-100)	2 (2-2)	30 (25-35)	7.5 (5-10)
Residential PV electricity	1.84 (1.56-2.11)	27.5 (25-30)	0.75 (0.5-1)	44 (41-47)	1.5 (1-2)
Commercial/government PV	1.27 (0.87-1.66)	16.5 (13-20)	0.75 (0.5-1)	46 (43-49)	1.5 (1-2)
Utility-scale PV electricity	0.71 (0.58-0.84)	19.5 (16.5-22.5)	0.75 (0.5-1)	48.5 (45-52)	7.5 (5-10)
CSP electricity with storage[a]	4.61 (3.62-5.60)	50 (40-60)	1.25 (1-1.5)	45 (40-50)	7.5 (5-10)
Geothermal electricity	4.64 (3.97-5.31)	45 (36-54)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Hydroelectricity	2.64 (2.36-3.20)	15.5 (15-16)	2.5 (2-3)	85 (70-100)	7.5 (5-10)
Wave electricity	4.13 (2.85-5.43)	175 (100-250)	2 (2-2)	45 (40-50)	7.5 (5-10)
Tidal electricity	3.68 (2.95-4.41)	125 (50-200)	2.5 (2-3)	45 (40-50)	7.5 (5-10)
Solar thermal heat	1.18 (1.06-1.29)	50 (40-60)	1.25 (1-1.5)	35 (30-40)	3 (2-4)
Geothermal heat	4.64 (3.97-5.31)	45 (36-54)	2 (1-3)	45 (40-50)	7.5 (5-10)

Capital costs (per MW of nameplate capacity) are an average of 2020 and 2050 values. 2050 costs are derived and sourced in ref. [S3], which uses the same methodology as in ref. [S14].

O&M=Operation and maintenance. TDM=transmission/distribution/maintenance. TDM losses are a percentage of all energy produced by the generator and are an average over short and long-distance (high-voltage direct current) lines.

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)(from [S6], but brought up to 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 S16 gives the total new HVDC line length and capacity needed and the fraction of all non-rooftop-PV and non-curtailed electricity generated that is subject to HVDC transmission by region. The discount rate used for generation, storage, transmission/distribution, and social costs is a social discount rate of 2 (1-3)%.

[a]The capital cost of CSP with storage includes the cost of extra mirrors and land but excludes costs of phase-change material and storage tanks, which are given in Table S27. The cost of CSP with storage depends on the ratio of the CSP storage maximum charge rate plus direct electricity use rate (which equals the maximum discharge rate) to the CSP maximum discharge rate. For this table, for the purpose of benchmarking the “CSP with storage” cost, we use a ratio of 3.2:1. (In other words, if 3.2 units of sunlight come in, a maximum of 2.2 units can go to storage and a maximum of 1 unit can be discharged directly as electricity at the same time.) The ratio for “CSP no storage” is 1:1. In our actual simulations and cost calculations, we assume a ratio of 2.612:1 for CSP with storage (footnote to Table S15) and find the cost for this assumed ratio by interpolating between the “CSP with storage” benchmark value and the “CSP no storage” value in this table.

Table S26. Parameters for Determining the Cost of Hydrogen, Related to STAR Methods.

Parameters for determining costs of hydrogen.

	Capital cost new installations	Installation factor	O&M Cost (annual fraction of capital cost)	Full-load life (y)	Calendar life (y)	Efficiency
Electrolyzer	\$334.5 (232-437)/kW-consumed[a]	1.25 (1.2-1.3)[e]	0.078[f]	10[g]	40[i]	0.96[j]
Rectifier	\$94 (84-103)/kW-consumed[b]	1.25 (1.2-1.3)[e]	0.01[f]	10[g]	40[i]	0.99[k]
Compressor	\$39.3 (35-43)/kW-consumed[b]	1.87[f]	0.04[f]	10[g]	40[i]	0.88[l]
H_2 Storage	\$250 (200-300)/kg-H_2-stored[c] \$11.8 (9.5-14.2)/kWh-stored[c]	1.25 (1.2-1.3)[e]	0.01[f]	15 (10-20)[h]	15 (10-20)[h]	0.997[l]
Fuel cell	\$500 (400-600)/kW-generated[d]	1.33[d]	0.035[d]	11[d]	40[i]	0.536[m]
Overall						0.447[n]

Capital costs are averages of 2020 and 2050 values and in 2020 USD. The discount rate used is the social discount rate of 2 (1-3)%. Amortization times for determining annual costs equal actual equipment lifetimes (as determined below under footnote g). Additional costs accounted for include the costs of water to produce hydrogen and the costs of dispensing hydrogen fuel to fuel-cell vehicles and to cool the hydrogen fuel. These costs are included and referenced in Table S28 (footnote).

[a]The low value is the "future potential" value from ref. [S35] and the high value is the "moderate 2030" value from ref. [S36]. \$334.5/kW is an average of the two.

[b][S36]. A rectifier is needed to convert AC electricity to DC electricity, which is used by the electrolyzer.

[c]The mean hydrogen storage container capital cost is approximately the "future case" estimate of \$245/kg-H_2 from ref. [S37]. Dividing the cost per kg-H_2-stored by the higher heating value of hydrogen (39.39 kWh/kg-H_2) and by the fuel cell overall efficiency (0.536) gives the cost of hydrogen storage per kWh of electricity stored.

[d][S38]. Assumed here for 2035.

[e][S39]. Installation factors account for the labor and materials cost of installation.

[f][S35].

[g]The electrolyzer full-load life (life with a use factor unity) today is 7-8.5 years [S40]. This is assumed here to increase to 10 years by 2035, the year for which calculations are performed. Rectifier and compressor full-load lives are estimated to be the same as that of an electrolyzer. Electrolyzer, rectifier, compressor, and fuel cell actual lifetimes are calculated in the model as a function of use factor. They are calculated as the full-load life of the equipment divided by the use factor, with the result limited by the calendar life of the equipment.

[h][S41] for the mean value. Hydrogen storage lifetime is assumed to be independent of use factor.

[i]The electrolyzer calendar life today is 30 years [S36]. This is assumed here to increase to 40 years by 2035, the year for which calculations are performed. Rectifier, compressor, and fuel cell full-load lives are assumed to be the same as that of an electrolyzer.

[j][S42]measured electrolyzer efficiencies of 95%-98% relative to the higher heating value of hydrogen (39.39 kWh/kg-H_2=141.8 MJ/kg-H_2). 96% is assumed for 2035.

[k][S43] estimates current rectifier efficiencies greater than 98%. The efficiency is assumed to be 99% in 2035.

[l][S44]. The storage efficiency assumes that 0.3% of hydrogen leaks between electrolyzer and fuel cell.

[m]Assumes a 2035 fuel cell energy conversion efficiency of 65%, an energy to DC electricity efficiency of 84.6% (the rest goes into heat evaporating water), and a DC to AC inverter efficiency of 97.5% [S44].

[n]The overall efficiency is the product of the efficiencies of the individual components.

Table S27. Parameters for Determining Storage Costs, Related to STAR Methods.
Present value of mean 2020 to 2050 lifecycle costs of new storage capacity and round-trip efficiencies of non-hydrogen storage technologies treated. Table S26 provides hydrogen storage cost data.

Storage technology	Present-value of lifecycle cost of new storage ($/kWh—electricity or equivalent electricity, in the case of cold and heat storage)			Round-trip charge/store/ discharge efficiency (%)
	Middle	Low	High	
Electricity				
PHS	14	12	16	80
CSP-PCM	20	15	23	55, 28.72, 99
LI Batteries	60	30	90	89.5
Cold				
CW-STES	12	0.4	40	84.7
ICE	100	40	160	82.5
Heat				
HW-STES	12	0.4	40	83
UTES	1.6	0.4	4	56

PHS=pumped hydropower storage; CSP-PCM=concentrated solar power with phase change material for storage; LI Batteries=lithium-ion batteries; CW-STES=cold water sensible-heat thermal energy storage; ICE=ice storage; HW-STES=hot water sensible-heat thermal energy storage; UTES=underground thermal energy storage in boreholes or water pits.

All values reflect averages between 2020 and 2050. From ref. [S14], except as follows.

PHS efficiency is the ratio of electricity delivered to the sum of electricity delivered and electricity used to pump the water. The 2020-2050 mean PHS round-trip efficiency estimated here (80%) can be compared with the U.S.-average value in 2019 of 79% [S45].

The CSP-PCM cost is for the PCM material and storage tanks. In the model, only the heat captured by the working fluid due to reflection of sunlight off of CSP mirrors can be stored. The three CSP-PCM efficiencies are as follows. 55% of incoming sunlight is reflected to the central tower, where it is absorbed by the working fluid (the remaining 45% of sunlight is lost to reflection and absorption by the CSP mirrors); without storage, 28.72% of heat absorbed by the working fluid is converted to electricity (the remaining 71.28% of heat is lost); and with storage, 99% of heat received by the working fluid that goes into storage is recovered and available to the steam turbine after storage [S46] and, of that, 28.72% is converted to electricity. Thus, the overall efficiency of CSP without storage is 15.785% and that with storage is 15.638%.

Ref. [S47] projects that LI battery cell costs for Tesla batteries to be ~$25/kWh by 2035. We estimate that the total system cost for an installed battery pack will be more than twice this, ~$60/kWh (or $240/kW for 4-hour batteries), by 2035 and take this as the mean between 2020 and 2050. Ref. [S48] calculated the average lithium-ion battery pack prices in December 2022 as $151/kWh but projected such prices would decline to below $100/kWh by 2026, suggesting again that a price decline to $60/kWh by 2035 is reasonable. For LI battery storage, the 2020-2050 mean round-trip efficiency is taken as the roundtrip efficiency of a 2021 Tesla Powerpack with four hours of storage [S49]. Battery efficiency is the ratio of electricity delivered to electricity put into the battery.

CW-STES, ICE, HW-STES, and UTES costs were updated to reflect average values between 2020 and 2050 rather than values in 2016, which they were previously based on. UTES costs were also updated with data from Denmark (p. 65 of ref. [S44]). In addition, the thermal energy storage (CW-STES, ICE, HW-STEES, and UTES) costs in $/kW-th were multiplied by the mean coefficient of performance (COP) of heat pumps used here (=4 kWh-th/kWh/electricity) to give the costs in $/kW-equivalent electricity. The reason is that most all energy in this study is carried in units of electricity, and heat pumps are assumed to provide heat or cold for thermal storage media. Thus, storage capacities are limited to the electricity needed to produce a larger amount of heat or cold. Since the storage size for heat or cold as equivalent electricity is smaller than the storage size of the heat or cold itself, the storage cost per unit equivalent electricity must be proportionately larger (by a factor of COP) for costs to be calculated consistently. The cost of heat pumps is assumed to be $160 (132-188)/kW-electricity, or $40 (33-47)/kW-th, based on data for large heat pumps (> 500 tons) projected to between 2020 and 2050.

CW-STES and HW-STES efficiencies are the ratios of the energy returned as cooling and heating, respectively, after storage, to the electricity input into storage. The UTES efficiency is the fraction of heated fluid entering underground storage that is ultimately returned during the year (either short or long term) as air or water heat for a building.

Storage costs per unit energy generated are the product of the maximum energy storage capacity (Table S15) and the lifecycle-averaged capital cost of storage per unit maximum energy storage capacity (this table), annualized with the same discount rate as for power generators (Table S26), but with average 2020 to 2050 storage lifetimes of 17 (12 to 22) years for batteries and 32.5 (25 to 40) years all other storage, all divided by the annual-average end-use demand met. At least one stationary storage battery (lithium-iron-phosphate) is warrantied up to 15,000 cycles (or 15 years) [S50]. 15,000 cycles are equivalent to one cycle per day (365 cycles per year) for 41.1 years, so this battery may last much longer than the 15-year warranty. As such, the 17-year mean battery life here is likely underestimated.

Table S28. Hydrogen Production and Cost, Related to Table 1.
Annual hydrogen produced and breakdown of cost per kilogram of hydrogen produced in each of the four cases treated here (Cases I-IV): The end-use demand is the same in all four cases. Mean, low, and high totals are given, but only the breakdown of the mean value is provided. Tables S25-S27 and the footnote to this table provide mean, low, and high capital cost, installation factor, and discount rate information. All costs are in units of 2020 \$/kg-H_2-produced. **Case I.** Base. Non-grid hydrogen only.

Region	(a) Non-grid H_2 produced (Tg-H_2/y)	(b) Mean non-grid H_2 electricity cost (\$/kg-H_2)	(c) Mean non-grid H_2 electro-lyzer + rectifier cost (\$/kg-H_2)	(d) Mean non-grid H_2 compres-sor cost (\$/kg-H_2)	(e) Mean non-grid H_2 water + dispen-sing + cooling cost (\$/kg-H_2)	(f) Mean non-grid H_2 storage cost (\$/kg-H_2)	(g) Mean non-grid H_2 total cost (\$/kg-H_2) =b+c+d+e+f	(h) Low non-grid H_2 total cost (\$/kg-H_2)	(i) High non-grid H_2 total cost (\$/kg-H_2)
Africa	8.674	4.06	1.47	0.018	0.18	1.43	7.17	5.17	10.21
Australia	1.761	3.98	1.47	0.018	0.18	1.32	6.97	5.06	9.78
Canada	2.682	3.10	0.41	0.006	0.18	0.00	3.70	3.04	4.47
Central America	2.463	5.11	1.47	0.018	0.18	1.40	8.18	5.85	11.68
Central Asia	2.582	3.75	1.47	0.018	0.18	0.28	5.70	4.35	7.47
China region	68.59	3.84	1.47	0.018	0.18	0.88	6.40	4.75	8.74
Cuba	0.067	5.72	1.47	0.018	0.18	2.28	9.67	6.50	14.84
Europe	23.11	3.98	1.47	0.018	0.18	0.90	6.55	4.86	8.95
Haiti region	0.136	4.11	1.47	0.018	0.18	0.66	6.44	4.77	8.85
Iceland	0.025	3.33	1.26	0.016	0.18	0.04	4.83	3.77	6.15
India region	19.65	3.85	1.47	0.018	0.18	0.07	5.59	4.13	7.62
Israel	0.148	5.87	0.41	0.006	0.18	0.00	6.47	4.32	9.98
Jamaica	0.062	4.98	1.47	0.018	0.18	0.37	7.02	5.10	9.77
Japan	5.532	4.42	1.47	0.018	0.18	0.59	6.68	4.96	9.06
Mauritius	0.069	5.53	1.47	0.018	0.18	3.45	10.66	7.20	16.34
Mideast	14.13	3.79	1.47	0.018	0.18	0.51	5.98	4.45	8.10
New Zealand	0.269	3.99	1.47	0.018	0.18	0.20	5.86	4.52	7.59
Philippines	0.848	5.11	1.47	0.018	0.18	0.66	7.44	5.23	10.84
Russia region	8.811	3.49	1.04	0.013	0.18	0.54	5.26	4.04	6.96
South America	9.029	4.19	1.47	0.018	0.18	0.15	6.01	4.66	7.69
Southeast Asia	13.14	5.88	1.47	0.018	0.18	0.59	8.14	6.04	11.04
South Korea	4.203	6.05	1.47	0.018	0.18	1.10	8.83	6.27	12.66
Taiwan	1.561	5.68	1.47	0.018	0.18	3.01	10.37	6.78	16.25
United States	14.12	4.20	1.47	0.018	0.18	0.96	6.84	5.01	9.46
All regions	**201.7**	**4.11**	**1.44**	**0.018**	**0.18**	**0.74**	**6.50**	**4.81**	**8.88**

Costs are averages of 2020 and 2050 values and in 2020 USD. The mean H_2 electricity cost for each region is the "Total LCOE" from Tables S33-S35 multiplied by 47.1 kWh/kg-H_2 for electrolysis plus compression. The value for "All regions" is the average of each regional value weighted by the hydrogen production in the region. Table S26 provides electrolyzer, rectifier, compressor, storage, and fuel cell capital costs, installation factors, operation and maintenance costs, lifetime information, and efficiencies. It also provides the discount rate used. For the electrolyzer plus rectifier and compressor, calculated annualized costs (\$/kW/y) are converted to costs per kg-H_2 by multiplying by 41.46 kWh/kg-H_2 and 5.64 kWh/kg-H_2, respectively, then dividing by 8,760 hours per year and by the hydrogen use factors for the region from Tables S18-S21 for each respective case. Storage costs per kg-H_2-produced equal annualized storage costs (\$/kg-H_2-stored/y) multiplied by the ratio of the H_2 storage tank size to the H_2 production per year, both from Tables S18-S21. The water cost for electrolysis is estimated as \$0.0071 (\$0.0047-\$0.0094)/kg-H_2-produced [S9]. The estimated costs to dispense hydrogen fuel to vehicles and to cool the hydrogen fuel to -40^{o}C are \$0.17 (0.12-0.21)/kg-H_2 and \$0.22 (0.18-0.27)/kg-H_2, respectively [S39]. However, because only ~45% of the non-grid H_2 needed worldwide will be for vehicles, the dispensing and cooling costs are multiplied by 0.45. Thus, the resulting summed cost of water, dispensing, and cooling for non-grid hydrogen is \$0.183 (0.14-0.225)/kg-H_2.

Table S29. Hydrogen Production and Cost, Related to Table 1.
Same as Table S28, except for **Case II.** Non-grid and grid hydrogen are merged together. The fuel cells are for grid hydrogen.

Region	(a) Non-grid plus grid H_2 pro-duced (Tg-H_2/y)	(b) Mean non-grid plus grid H_2 electricity cost ($/kg-$H_2$)	(c) Mean non-grid plus grid H_2 electro-lyzer + rectifier cost ($/kg-$H_2$)	(d) Mean non-grid plus grid H_2 comp-ressor cost ($/kg-$H_2$)	(e) Mean non-grid plus grid H_2 water + dispen-sing + cooling cost ($/kg-$H_2$)	(f) Mean non-grid plus grid H_2 storage cost ($/kg-$H_2$)	(g) Mean grid H_2 fuel cell cost ($/kg-$H_2$)	(h) Mean non-grid plus grid total H_2 cost ($/kg-$H_2$) =b+c+d+e +f+g	(i) Low non-grid plus grid total H_2 cost ($/kg-$H_2$)	(j) High non-grid plus grid total H_2 cost ($/kg-$H_2$)
Africa	8.829	4.03	1.44	0.018	0.18	0.65	0.19	6.51	4.82	8.94
Australia	1.803	3.94	1.44	0.018	0.18	1.15	0.23	6.96	5.10	9.63
Canada	2.682	3.10	0.41	0.006	0.18	0.00	0.00	3.70	3.04	4.47
Central America	2.522	4.79	1.44	0.018	0.18	2.08	0.27	8.77	6.32	12.50
Central Asia	2.706	3.79	1.40	0.017	0.18	0.77	0.31	6.48	4.84	8.74
China region	81.66	4.08	1.24	0.015	0.18	1.85	0.26	7.62	5.47	10.90
Cuba	0.072	5.58	4.57	0.057	0.18	4.20	4.66	19.24	13.10	28.33
Europe	35.31	4.12	0.96	0.012	0.18	1.44	0.25	6.97	5.13	9.75
Haiti region	0.136	4.09	1.47	0.018	0.18	0.81	0.08	6.64	4.90	9.16
Iceland	0.025	3.33	1.26	0.016	0.18	0.04	0	4.83	3.77	6.15
India region	19.79	3.79	1.46	0.018	0.18	1.02	0.75	7.23	5.23	10.10
Israel	0.149	5.16	1.46	0.018	0.18	2.90	1.40	11.11	7.50	16.92
Jamaica	0.063	4.92	1.45	0.018	0.18	1.05	0.80	8.41	6.08	11.79
Japan	5.691	4.39	1.43	0.018	0.18	0.82	0.29	7.13	5.29	9.69
Mauritius	0.071	5.72	1.62	0.020	0.18	4.26	1.65	13.44	9.18	20.24
Mideast	14.32	3.78	1.45	0.018	0.18	0.80	0.41	6.64	4.92	9.07
New Zealand	0.306	3.94	1.29	0.016	0.18	0.42	0.19	6.04	4.66	7.87
Philippines	1.254	5.33	1.44	0.018	0.18	3.88	1.47	12.31	8.41	18.61
Russia region	8.811	3.49	1.04	0.013	0.18	0.54	0.00	5.26	4.04	6.96
South America	9.03	4.19	1.47	0.018	0.18	0.15	0.00	6.01	4.66	7.69
Southeast Asia	13.19	5.91	1.46	0.018	0.18	0.66	0.41	8.64	6.41	11.72
South Korea	4.451	5.80	1.39	0.017	0.18	2.15	0.94	10.48	7.49	15.00
Taiwan	1.589	4.79	1.45	0.018	0.18	4.33	0.79	11.56	7.83	17.67
United States	14.31	4.12	1.45	0.018	0.18	1.31	0.45	7.53	5.51	10.43
All regions	**228.8**	**4.18**	**1.29**	**0.016**	**0.18**	**1.31**	**0.28**	**7.27**	**5.31**	**10.15**

Table S30. Hydrogen Production and Cost, Related to Table 1.
Same as Table S28, except for **Case III.** Non-grid and grid hydrogen are treated separately (separate electrolyzers, rectifiers, compressors, storage) and fuel cells are used for grid electricity generation. Cost of non-grid hydrogen. See Table S31 for the cost of grid hydrogen and the overall cost.

Region	(a) Non-grid H_2 produced (Tg-H_2/y)	(b) Mean non-grid H_2 elec-tricity cost ($/kg-$H_2$)	(c) Mean non-grid H_2 electro-lyzer + rectifier cost ($/kg-$H_2$	(d) Mean non-grid H_2 compres-sor cost ($/kg-$H_2$)	(e) Mean non-grid H_2 water + dispensing + cooling cost ($/kg-$H_2$)	(f) Mean non-grid H_2 storage cost ($/kg-$H_2$)	(g) Mean non-grid H_2 total cost ($/kg-$H_2$) =b+c+d+e+f	(h) Low non-grid H_2 total cost ($/kg-$H_2$)	(i) High non-grid H_2 total cost ($/kg-$H_2$)
Africa	8.674	4.08	1.47	0.02	0.18	1.62	7.37	5.29	10.57
Australia	1.761	4.41	1.47	0.02	0.18	0.73	6.81	5.02	9.36
Canada	2.682	3.10	0.41	0.01	0.18	0.00	3.70	3.04	4.47
Central America	2.463	4.90	1.47	0.02	0.18	0.88	7.45	5.55	10.16
Central Asia	2.582	3.78	1.47	0.02	0.18	0.22	5.67	4.34	7.40
China region	68.59	3.89	1.47	0.02	0.18	1.10	6.66	4.91	9.20
Cuba	0.067	5.58	1.47	0.02	0.18	2.35	9.61	6.69	14.34
Europe	23.11	3.98	1.47	0.02	0.18	0.94	6.59	4.89	9.02
Haiti region	0.136	4.18	1.47	0.02	0.18	1.03	6.88	5.03	9.61
Iceland	0.025	3.33	1.26	0.02	0.18	0.04	4.83	3.77	6.15
India region	19.65	3.99	1.47	0.02	0.18	1.84	7.50	5.30	10.92
Israel	0.148	4.92	1.47	0.02	0.18	2.35	8.94	6.21	13.35
Jamaica	0.062	5.01	1.47	0.02	0.18	0.37	7.05	5.19	9.69
Japan	5.532	4.39	1.47	0.02	0.18	0.66	6.72	5.02	9.08
Mauritius	0.069	5.92	1.47	0.02	0.18	4.41	12.00	8.09	18.52
Mideast	14.13	3.78	1.47	0.02	0.18	0.51	5.97	4.48	8.00
New Zealand	0.269	3.94	1.47	0.02	0.18	0.22	5.84	4.53	7.51
Philippines	0.848	5.21	1.47	0.02	0.18	0.81	7.69	5.54	10.92
Russia region	8.811	3.49	1.04	0.01	0.18	0.54	5.26	4.04	6.96
South America	9.029	4.19	1.47	0.02	0.18	0.15	6.01	4.66	7.69
Southeast Asia	13.14	5.90	1.47	0.02	0.18	0.66	8.23	6.11	11.16
South Korea	4.203	5.87	1.47	0.02	0.18	1.10	8.64	6.32	12.03
Taiwan	1.561	5.01	1.47	0.02	0.18	4.04	10.72	7.22	16.51
United States	14.12	4.11	1.47	0.02	0.18	1.10	6.88	5.08	9.47
All regions	**201.7**	**4.13**	**1.44**	**0.02**	**0.18**	**1.02**	**6.79**	**5.00**	**9.36**

Table S31. Hydrogen Production and Cost, Related to Table 1.

Continuation of Table S30 for **Case III.** Grid hydrogen cost and overall cost.

Region	(j) Grid H_2 pro-duced (Tg-H_2/y)	(k) Mean grid H_2 elec-tricity cost ($/kg-$H_2$)	(l) Mean grid H_2 electro-lyzer + rectifier cost ($/kg-$H_2$)	(m) Mean grid H_2 com-pres-sor cost ($/kg -$H_2$)	(n) Mean grid H_2 water cost ($/kg-$H_2$)	(o) Mean grid H_2 stor-age cost ($/kg-$H_2$)	(p) Mean grid H_2 fuel cell cost ($/kg-$H_2$)	(q) Mean grid H_2 total cost ($/kg-$H_2$) =k+l+ m+n+ o+p	(r) Low grid H_2 total cost ($/kg-$H_2$)	(s) High grid H_2 total cost ($/kg-$H_2$)	(t) Mean grid +non-grid H_2 total cost ($/kg-$H_2$) = (ag+jq)/ (a+j)	(u) Low grid+ non-grid H_2 total cost ($/kg-$H_2$) = (ah+jr)/ (a+j)	(v) High grid+ non-grid H_2 total cost ($/kg-$H_2$) = (ai+js)/ (a+j)
Africa	0.120	4.08	3.42	0.04	0.007	0.53	3.49	11.58	8.35	15.79	7.43	5.33	10.64
Australia	1.996	4.41	0.81	0.01	0.007	3.64	0.80	9.67	6.67	14.53	8.33	5.90	12.10
Canada	0	0	0	0	0	0	0	0	0	0	3.70	3.04	4.47
Central America	0.640	4.90	2.44	0.03	0.007	9.08	2.48	18.94	12.53	29.51	9.82	6.99	14.15
Central Asia	0.128	3.78	5.44	0.07	0.007	6.59	5.55	21.44	14.49	31.77	6.42	4.82	8.55
China region	2.093	3.89	2.94	0.04	0.007	0.37	3.00	10.24	7.49	13.72	6.77	4.98	9.34
Cuba	0.038	5.58	5.34	0.07	0.007	22.40	5.45	38.85	24.50	63.28	20.23	13.15	32.11
Europe	0.454	3.98	2.71	0.03	0.007	2.02	2.76	11.52	8.20	16.20	6.69	4.96	9.15
Haiti region	0.000	4.18	258.23	3.21	0.007	40.08	263.13	568.84	387.72	794.40	7.54	5.48	10.53
Iceland	0	0	0	0	0	0	0	0	0	0	4.83	3.77	6.15
India region	2.038	3.99	7.15	0.09	0.007	7.77	7.28	26.29	17.57	39.21	9.27	6.45	13.58
Israel	0.018	4.92	20.36	0.25	0.007	30.97	20.75	77.26	49.93	119.50	16.40	10.99	24.94
Jamaica	0.001	5.01	42.39	0.53	0.007	26.32	43.20	117.46	78.23	172.09	8.91	6.42	12.42
Japan	0.085	4.39	9.67	0.12	0.007	10.51	9.85	34.55	23.06	51.48	7.14	5.29	9.72
Mauritius	0.017	5.92	2.47	0.03	0.007	9.59	2.52	20.53	13.39	32.47	13.66	9.13	21.24
Mideast	1.304	3.78	3.78	0.05	0.007	4.69	3.85	16.15	11.04	23.76	6.83	5.04	9.33
New Zealand	0.028	3.94	1.64	0.02	0.007	1.47	1.67	8.75	6.42	12.03	6.11	4.70	7.93
Philippines	0.087	5.21	19.24	0.24	0.007	14.94	19.61	59.24	39.42	87.64	12.51	8.70	18.09
Russia region	0	0	0	0	0	0	0	0	0	0	5.26	4.04	6.96
South America	0	0	0	0	0	0	0	0	0	0	6.01	4.66	7.69
Southeast Asia	0.070	5.90	46.75	0.58	0.007	10.16	47.64	111.03	75.87	155.76	8.78	6.49	11.93
South Korea	0.365	5.87	8.99	0.11	0.007	13.95	9.16	38.08	25.12	57.99	10.99	7.82	15.70
Taiwan	0.060	5.01	19.19	0.24	0.007	35.74	19.55	79.73	51.05	124.99	13.27	8.84	20.52
United States	0.120	4.11	31.10	0.39	0.007	12.55	31.69	79.83	54.03	114.20	7.50	5.49	10.36
All regions	**9.66**	**4.20**	**4.75**	**0.06**	**0.007**	**5.27**	**4.83**	**19.12**	**13.00**	**28.14**	**7.35**	**5.37**	**10.22**

Table S32. Hydrogen Production and Cost, Related to Table 1.
Same as Table S28, except for **Case IV.** Non-grid and grid hydrogen are merged together, and no batteries are allowed. The fuel cells are for grid hydrogen.

Region	(a) Non-grid plus grid H_2 produced ($Tg-H_2/y$)	(b) Mean non-grid plus grid H_2 electricity cost ($/kg-$H_2$)	(c) Mean non-grid plus grid H_2 electrolyzer + rectifier cost ($/kg-$H_2$)	(d) Mean non-grid plus grid H_2 compressor cost ($/kg-$H_2$)	(e) Mean non-grid plus grid H_2 water + dispensing + cooling cost ($/kg-$H_2$)	(f) Mean non-grid plus grid H_2 storage cost ($/kg-$H_2$)	(g) Mean grid H_2 fuel cell cost ($/kg-$H_2$)	(h) Mean non-grid plus grid total H_2 cost ($/kg-$H_2$) =b+c+d+e+f+g	(i) Low non-grid plus grid total H_2 cost ($/kg-$H_2$)	(j) High non-grid plus grid total H_2 cost ($/kg-$H_2$)
Africa	22.14	4.64	0.81	0.010	0.18	1.64	0.79	8.07	5.84	11.51
Australia	3.09	4.84	1.04	0.013	0.18	0.38	1.06	7.50	5.73	9.79
Canada	2.68	3.10	0.41	0.006	0.18	0.00	0.00	3.70	3.04	4.47
Central America	3.12	5.15	1.16	0.014	0.18	0.41	0.21	7.13	5.48	9.33
Central Asia	4.13	3.86	0.92	0.011	0.18	1.15	0.36	6.48	4.83	8.89
China region	120.81	4.15	0.85	0.011	0.18	1.46	0.22	6.88	5.04	9.67
Cuba	0.33	7.06	2.51	0.031	0.18	0.89	2.55	13.23	9.69	18.05
Europe	36.21	4.18	0.94	0.012	0.18	1.69	0.26	7.27	5.29	10.28
Haiti region	0.40	5.94	1.55	0.019	0.18	1.29	1.58	10.57	7.77	14.50
Iceland	0.03	3.33	1.26	0.016	0.18	0.04	0	4.83	3.77	6.15
India region	60.94	4.24	0.83	0.010	0.18	0.71	0.82	6.80	5.08	9.22
Israel	1.36	6.38	1.05	0.013	0.18	1.56	1.07	10.27	7.37	14.67
Jamaica	0.21	5.76	1.18	0.015	0.18	0.33	1.20	8.67	6.54	11.46
Japan	8.68	4.50	0.94	0.012	0.18	0.56	0.24	6.44	4.92	8.50
Mauritius	0.12	6.34	0.99	0.012	0.18	3.65	1.01	12.18	8.43	18.24
Mideast	31.07	3.86	0.73	0.009	0.18	0.70	0.28	5.76	4.40	7.70
New Zealand	0.31	3.95	1.26	0.016	0.18	0.44	0.23	6.07	4.68	7.92
Philippines	3.73	5.92	1.10	0.014	0.18	0.80	1.12	9.14	6.71	12.64
Russia region	8.81	3.49	1.04	0.013	0.18	0.54	0.00	5.26	4.04	6.96
South America	9.03	4.19	1.47	0.018	0.18	0.15	0.00	6.01	4.66	7.69
Southeast Asia	40.55	6.87	0.99	0.012	0.18	1.33	1.01	10.40	7.62	14.39
South Korea	7.95	6.48	0.88	0.011	0.18	1.90	0.89	10.35	7.52	14.59
Taiwan	4.58	5.56	1.43	0.018	0.18	1.45	1.46	10.11	7.36	14.07
United States	34.76	4.80	0.94	0.012	0.18	2.36	0.96	9.26	6.66	13.23
All regions	**405.0**	**4.44**	**0.91**	**0.011**	**0.18**	**1.26**	**0.63**	**7.44**	**5.49**	**10.29**

Table S33. Summary of Costs by Region, Related to Table 1.
Summary of WWS mean capital costs in each of the four cases here (Cases I-IV) ($ 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 for each case in each region. Also shown is the energy consumed per year and the resulting aggregate annual energy cost to the region. The last row in each case is the percent increase in the total LCOE and the total annual energy cost if the baseline battery system cost is increased from the mean value in Table S27 ($60/kWh-electricity storage) to the high value ($90/kWh-electricity storage), or by a factor of 1.5. All costs are averages between 2020 and 2050. Regions in this table are shown alphabetically from A-I. Table S34 shows regions J-Z. Table S35 shows the sum of all regions.

	Africa				Australia			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	2.848	2.848	2.848	3.014	0.465	0.465	0.465	0.686
Cap cost generators-storage-H_2-HVDC ($tril)	**3.627**	**3.604**	**3.639**	**4.166**	**0.618**	**0.611**	**0.687**	**0.816**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.140	0.140	0.140	0.144	0.170	0.171	0.182	0.136
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	3.907	3.907	3.907	4.178	3.591	3.591	3.591	5.556
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.006	0.006	0.006	0.006	0.072	0.072	0.072	0.072
LI battery storage	0.217	0.256	0.193	0	0.479	0.378	0.202	0
Grid H_2 production/compression/storage/fuel cell	0	0.040	0.021	0.416	0	0.052	1.299	0.403
CSP-PCM + PHS storage	0.023	0.023	0.023	0.023	0.028	0.028	0.028	0.028
CW-STES + ICE storage	0.003	0.003	0.003	0.003	0.001	0.001	0.001	0.001
HW-STES storage	0.005	0.005	0.005	0.005	0.002	0.002	0.002	0.002
UTES storage	0.187	0.187	0.187	0.187	0.003	0.003	0.003	0.003
Heat pumps for filling district heating/cooling	0.079	0.079	0.079	0.079	0.028	0.028	0.028	0.028
Non-grid H_2 production/compression/storage	0.638	0.480	0.675	1.384	0.652	0.621	0.524	0.615
Total LCOE (¢/kWh-all-energy)	**8.630**	**8.551**	**8.665**	**9.850**	**8.451**	**8.371**	**9.356**	**10.268**
LCOE (¢/kWh-replacing BAU electricity)	7.709	7.787	7.706	8.181	7.750	7.701	8.782	9.608
GW annual avg. end-use demand (Table S8)	482.1	482.1	482.1	482.1	92.3	92.3	92.3	92.3
TWh/y end-use demand (GW x 8,760 h/y)	4,224	4,224	4,224	4,224	808	808	808	808
Annual energy cost ($billion/y)	**364.5**	**361.2**	**366.0**	**416.0**	**68.3**	**67.7**	**75.6**	**83.0**
% rise in LCOE & annual cost if 1.5x battery cost	1.26	1.50	1.11	0	2.84	2.26	1.08	0
	Canada				Central America			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.510	0.510	0.510	0.510	1.127	1.127	1.127	1.426
Cap cost generators-storage-H_2-HVDC ($tril)	**0.654**	**0.654**	**0.654**	**0.654**	**1.445**	**1.331**	**1.358**	**1.548**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.218	0.218	0.218	0.218	0.095	0.095	0.096	0.084
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	2.747	2.747	2.747	2.747	5.530	5.530	5.530	6.857
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.028	0.028	0.028	0.028	0.022	0.022	0.022	0.022
LI battery storage	0	0	0	0	1.175	0.312	0.164	0
Grid H_2 production/compression/storage/fuel cell	0	0	0	0	0	0.049	0.655	0.049
CSP-PCM + PHS storage	0	0	0	0	0.020	0.020	0.020	0.065
CW-STES + ICE storage	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002
HW-STES storage	0.009	0.009	0.009	0.009	0.003	0.003	0.003	0.003
UTES storage	0.007	0.007	0.007	0.007	0.004	0.004	0.004	0.004
Heat pumps for filling district heating/cooling	0.032	0.032	0.032	0.032	0.027	0.027	0.027	0.027
Non-grid H_2 production/compression/storage	0.108	0.108	0.108	0.108	0.551	0.684	0.459	0.401
Total LCOE (¢/kWh-all-energy)	**6.574**	**6.574**	**6.574**	**6.574**	**10.854**	**10.173**	**10.406**	**10.940**
LCOE (¢/kWh-replacing BAU electricity)	6.400	6.400	6.400	6.400	10.261	9.447	9.905	10.497
GW annual avg. end-use demand (Table S8)	170.3	170.3	170.3	170.3	156.5	156.5	156.5	156.5
TWh/y end-use demand (GW x 8,760 h/y)	1,492	1,492	1,492	1,492	1,371	1,371	1,371	1,371
Annual energy cost ($billion/y)	**98.1**	**98.1**	**98.1**	**98.1**	**148.8**	**139.5**	**142.7**	**150.0**
% rise in LCOE & annual cost if 1.5x battery cost	0.00	0.00	0.00	0	5.41	1.53	0.79	0

	Central Asia				China region			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.907	0.907	0.907	0.912	10.402	10.402	10.402	10.636
Cap cost generators-storage-H_2-HVDC ($tril)	**1.076**	**1.090**	**1.086**	**1.108**	**14.445**	**15.448**	**14.641**	**15.717**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.126	0.127	0.127	0.130	0.195	0.196	0.195	0.199
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	3.776	3.776	3.776	3.796	3.224	3.224	3.224	3.312
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.000	0.000	0.000	0.000	0.177	0.177	0.177	0.177
LI battery storage	0.181	0.126	0.112	0	0.162	0.120	0.127	0
Grid H_2 production/compression/storage/fuel cell	0	0.057	0.155	0.103	0	0.098	0.063	0.128
CSP-PCM + PHS storage	0.023	0.023	0.023	0.023	0.020	0.020	0.020	0.020
CW-STES + ICE storage	0	0	0	0	0.002	0.002	0.002	0.002
HW-STES storage	0.010	0.010	0.010	0.010	0.005	0.005	0.005	0.005
UTES storage	0.037	0.037	0.037	0.037	0.063	0.063	0.063	0.063
Heat pumps for filling district heating/cooling	0.029	0.029	0.029	0.029	0.064	0.064	0.064	0.064
Non-grid H_2 production/compression/storage	0.345	0.440	0.334	0.639	0.825	1.263	0.896	1.423
Total LCOE (¢/kWh-all-energy)	**7.953**	**8.050**	**8.028**	**8.191**	**8.162**	**8.658**	**8.261**	**8.819**
LCOE (¢/kWh-replacing BAU electricity)	7.522	7.524	7.607	7.466	7.175	7.232	7.202	7.233
GW annual avg. end-use demand (Table S8)	166.9	166.9	166.9	166.9	2,423.9	2,423.9	2,423.9	2,423.9
TWh/y end-use demand (GW x 8,760 h/y)	1,462	1,462	1,462	1,462	21,234	21,234	21,234	21,234
Annual energy cost ($billion/y)	**116.3**	**117.7**	**117.3**	**119.7**	**1,733.1**	**1,838.5**	**1,754.1**	**1,872.5**
% rise in LCOE & annual cost if 1.5x battery cost	1.14	0.78	0.70	0	1.00	0.70	0.77	0
	Cuba				Europe			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.073	0.073	0.073	0.106	4.239	4.239	4.239	4.239
Cap cost generators-storage-H_2-HVDC ($tril)	**0.103**	**0.099**	**0.098**	**0.131**	**5.785**	**5.997**	**5.777**	**6.097**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0	0	0	0	0.191	0.197	0.192	0.198
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	5.555	5.555	5.555	8.640	3.656	3.656	3.656	3.656
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0	0	0	0	0.115	0.115	0.115	0.115
LI battery storage	2.460	1.243	0.544	0	0.202	0.004	0.147	0
Grid H_2 production/compression/storage/fuel cell	0	0.425	1.621	1.062	0	0.105	0.041	0.112
CSP-PCM + PHS storage	0.058	0.058	0.058	0.058	0.023	0.023	0.023	0.023
CW-STES + ICE storage	0.004	0.004	0.004	0.004	0.002	0.002	0.002	0.002
HW-STES storage	0.012	0.012	0.012	0.012	0.015	0.015	0.015	0.015
UTES storage	0.242	0.242	0.242	0.242	0.041	0.041	0.041	0.041
Heat pumps for filling district heating/cooling	0.052	0.052	0.052	0.052	0.081	0.081	0.081	0.081
Non-grid H_2 production/compression/storage	0.338	0.822	0.344	1.501	0.707	1.093	0.719	1.217
Total LCOE (¢/kWh-all-energy)	**12.146**	**11.837**	**11.857**	**14.995**	**8.458**	**8.757**	**8.456**	**8.885**
LCOE (¢/kWh-replacing BAU electricity)	11.503	10.711	11.208	13.189	7.589	7.501	7.575	7.505
GW annual avg. end-use demand (Table S8)	9.0	9.0	9.0	9.0	958.3	958.3	958.3	958.3
TWh/y end-use demand (GW x 8,760 h/y)	79	79	79	79	8,394	8,394	8,394	8,394
Annual energy cost ($billion/y)	**9.6**	**9.3**	**9.3**	**11.8**	**710.0**	**735.1**	**709.9**	**745.8**
% rise in LCOE & annual cost if 1.5x battery cost	10.1	5.2	2.3	0	1.19	0.02	0.86	0

	Haiti region				Iceland			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.045	0.045	0.045	0.067	0.002	0.002	0.002	0.002
Cap cost generators-storage-H_2-HVDC ($tril)	**0.055**	**0.055**	**0.056**	**0.087**	**0.0029**	**0.0029**	**0.0029**	**0.0029**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0	0	0	0	0	0	0	0
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	3.931	3.931	3.931	6.222	1.777	1.777	1.777	1.777
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0	0	0	0	1.679	1.679	1.679	1.679
LI battery storage	0.674	0.582	0.613	0	0	0	0	0
Grid H_2 production/compression/storage/fuel cell	0	0.016	0.135	0.942	0	0	0	0
CSP-PCM + PHS storage	0.048	0.048	0.048	0.048	0	0	0	0
CW-STES + ICE storage	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
HW-STES storage	0	0	0	0	0.005	0.005	0.005	0.005
UTES storage	0.026	0.026	0.026	0.026	0	0	0	0
Heat pumps for filling district heating/cooling	0.138	0.138	0.138	0.138	0.046	0.046	0.046	0.046
Non-grid H_2 production/compression/storage	0.477	0.507	0.552	1.810	0.137	0.137	0.137	0.137
Total LCOE (¢/kWh-all-energy)	**8.721**	**8.675**	**8.869**	**12.614**	**7.071**	**7.071**	**7.071**	**7.071**
LCOE (¢/kWh-replacing BAU electricity)	8.080	8.004	8.154	10.639	6.883	6.883	6.883	6.883
GW annual avg. end-use demand (Table S8)	7.6	7.6	7.6	7.6	3.2	3.2	3.2	3.2
TWh/y end-use demand (GW x 8,760 h/y)	67	67	67	67	28	28	28	28
Annual energy cost ($billion/y)	**5.8**	**5.8**	**5.9**	**8.4**	**2.0**	**2.0**	**2.0**	**2.0**
% rise in LCOE & annual cost if 1.5x battery cost	3.86	3.35	3.45	0	0	0	0	0

LI=lithium ion; CSP=concentrated solar power; PCM=Phase-change materials; PHS=pumped hydropower storage; CW-STES=Chilled-water sensible heat thermal energy storage; ICE=ice storage; HW-STES=Hot water sensible heat thermal energy storage; and UTES=Underground thermal energy storage in boreholes or water pits.

The LCOEs are derived from capital costs, annual O&M, and end-of-life decommissioning costs that vary by technology (Tables S25-S27) and that are a function of lifetime (Tables S25-S27) 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 costs are an average between 2020 and 2050, as are the LCOEs.

Capital cost of generators-storage-H_2-HVDC ($trillion) is the capital cost of new electricity and heat generation, short- and long-distance (HVDC) transmission and distribution, battery storage, concentrated solar power with storage, pumped hydropower storage, cold water storage, ice storage, hot water storage, underground thermal energy storage, heat pumps for district heating and cooling, and hydrogen production and use-electrolyzers, rectifiers, storage tanks, water, dispensing, cooling, and fuel cells.

Since the total end-use demand includes heat, cold, hydrogen, and electricity demands (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 demand 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) (Ref. [S7], but brought up to 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 S16 gives the total HVDC line length and capacity and the fraction of all non-rooftop-PV and non-curtailed electricity generated that is subject to HVDC transmission by region.

Storage costs are derived as described in Table S27.

H_2 costs are broken down in Tables S28-S32..

Table S34. Summary of Costs by Region, Related to Table 1.
Same as Table S33, except for regions alphabetically from J-Z.

	India region				Israel			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	4.674	4.674	4.674	5.124	0.078	0.078	0.078	0.093
Cap cost generators-storage-H_2-HVDC ($tril)	**6.892**	**6.723**	**7.055**	**7.527**	**0.141**	**0.120**	**0.111**	**0.150**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.175	0.175	0.176	0.172	0.000	0.000	0.000	0.000
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	2.979	2.979	2.979	3.386	4.009	4.009	4.009	4.810
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.010	0.010	0.010	0.010	0.277	0.277	0.277	0.277
LI battery storage	0.948	0.446	0.347	0	4.374	2.150	0.729	0
Grid H_2 production/compression/storage/fuel cell	0	0.168	0.515	0.569	0	0.187	1.172	1.308
CSP-PCM + PHS storage	0.030	0.030	0.030	0.030	0.022	0.022	0.022	0.022
CW-STES + ICE storage	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003
HW-STES storage	0.020	0.020	0.020	0.020	0.014	0.014	0.014	0.014
UTES storage	0.106	0.106	0.106	0.106	0.203	0.203	0.203	0.203
Heat pumps for filling district heating/cooling	0.090	0.090	0.090	0.090	0.058	0.058	0.058	0.058
Non-grid H_2 production/compression/storage	0.389	0.602	0.782	1.197	0.079	0.608	0.532	3.427
Total LCOE (¢/kWh-all-energy)	**8.173**	**8.053**	**8.481**	**9.007**	**12.464**	**10.956**	**10.444**	**13.547**
LCOE (¢/kWh-replacing BAU electricity)	7.550	7.216	7.465	7.575	12.110	10.073	9.637	9.845
GW annual avg. end-use demand (Table S8)	1,007	1,006.8	1,006.8	1,006.8	12.8	12.8	12.8	12.8
TWh/y end-use demand (GW x 8,760 h/y)	8,820	8,820	8,820	8,820	112	112	112	112
Annual energy cost ($billion/y)	**720.9**	**710.2**	**748.0**	**794.4**	**13.9**	**12.3**	**11.7**	**15.2**
% rise in LCOE & annual cost if 1.5x battery cost	5.80	2.77	2.04	0	17.5	9.8	3.5	0

	Jamaica				Japan			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.019	0.019	0.019	0.023	0.991	0.991	0.991	1.117
Cap cost generators-storage-H_2-HVDC ($tril)	**0.025**	**0.024**	**0.025**	**0.029**	**1.311**	**1.293**	**1.293**	**1.371**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0	0	0	0	0.149	0.149	0.149	0.137
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	5.089	5.089	5.089	5.962	4.415	4.415	4.415	4.848
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0	0	0	0	0.045	0.045	0.045	0.045
LI battery storage	1.367	0.820	0.911	0	0.512	0.250	0.262	0
Grid H_2 production/compression/storage/fuel cell	0	0.224	0.535	1.121	0	0.102	0.157	0.128
CSP-PCM + PHS storage	0.023	0.023	0.023	0.023	0.047	0.047	0.047	0.047
CW-STES + ICE storage	0	0	0	0	0	0	0	0
HW-STES storage	0.017	0.017	0.017	0.017	0.002	0.002	0.002	0.002
UTES storage	0.027	0.027	0.027	0.027	0.006	0.006	0.006	0.006
Heat pumps for filling district heating/cooling	0.055	0.055	0.055	0.055	0.021	0.021	0.021	0.021
Non-grid H_2 production/compression/storage	0.564	0.758	0.564	1.588	0.766	0.855	0.791	0.901
Total LCOE (¢/kWh-all-energy)	**10.567**	**10.438**	**10.646**	**12.219**	**9.388**	**9.317**	**9.320**	**9.560**
LCOE (¢/kWh-replacing BAU electricity)	9.903	9.581	9.983	10.531	8.570	8.410	8.477	8.609
GW annual avg. end-use demand (Table S8)	2.6	2.6	2.6	2.6	186.3	186.3	186.3	186.3
TWh/y end-use demand (GW x 8,760 h/y)	22	22	22	22	1,632	1,632	1,632	1,632
Annual energy cost ($billion/y)	**2.4**	**2.3**	**2.4**	**2.7**	**153.2**	**152.1**	**152.1**	**156.0**
% rise in LCOE & annual cost if 1.5x battery cost	6.47	3.93	4.28	0	2.73	1.34	1.41	0

	Mauritius				Mideast			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.012	0.012	0.012	0.014	3.374	3.374	3.374	3.510
Cap cost generators-storage-H_2-HVDC ($tril)	**0.018**	**0.018**	**0.019**	**0.021**	**4.523**	**4.502**	**4.479**	**4.545**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0	0	0	0	0.162	0.162	0.163	0.164
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375

Electricity generation	4.804	4.804	4.804	5.546	3.300	3.300	3.300	3.476
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.049	0.049	0.049	0.049	0.039	0.039	0.039	0.039
LI battery storage	1.292	0.492	0.246	0	0.494	0.316	0.208	0
Grid H_2 production/compression/storage/fuel cell	0	0.706	1.464	0.757	0	0.095	0.261	0.142
CSP-PCM + PHS storage	0.013	0.013	0.013	0.013	0.016	0.016	0.016	0.016
CW-STES + ICE storage	0.005	0.005	0.005	0.005	0.001	0.001	0.001	0.001
HW-STES storage	0.001	0.001	0.001	0.001	0.002	0.002	0.002	0.002
UTES storage	0.023	0.023	0.023	0.023	0.085	0.085	0.085	0.085
Heat pumps for filling district heating/cooling	0.012	0.012	0.012	0.012	0.029	0.029	0.029	0.029
Non-grid H_2 production/compression/storage	2.122	2.605	2.517	3.627	0.499	0.567	0.499	0.814
Total LCOE (¢/kWh-all-energy)	**11.746**	**12.136**	**12.559**	**13.457**	**8.051**	**8.035**	**8.025**	**8.192**
LCOE (¢/kWh-replacing BAU electricity)	9.589	9.495	10.007	9.795	7.419	7.336	7.394	7.245
GW annual avg. end-use demand (Table S8)	1.9	1.9	1.9	1.9	706.5	706.5	706.5	706.5
TWh/y end-use demand (GW x 8,760 h/y)	17	17	17	17	6,189	6,189	6,189	6,189
Annual energy cost ($billion/y)	**1.9**	**2.0**	**2.1**	**2.2**	**498.3**	**497.3**	**496.7**	**507.0**
% rise in LCOE & annual cost if 1.5x battery cost	5.50	2.03	0.98	0	3.07	1.97	1.29	0

	New Zealand				Philippines			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.086	0.086	0.086	0.086	0.286	0.286	0.286	0.330
Cap cost generators-storage-H_2-HVDC ($tril)	**0.098**	**0.096**	**0.096**	**0.096**	**0.412**	**0.419**	**0.413**	**0.482**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.066	0.067	0.067	0.067	0.088	0.091	0.089	0.092
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	4.323	4.323	4.323	4.323	4.640	4.640	4.640	5.337
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.076	0.076	0.076	0.076	0	0	0	0
LI battery storage	0.195	0.004	0.008	0	1.765	0.341	0.624	0
Grid H_2 production/compression/storage/fuel cell	0	0.040	0.091	0.049	0	0.512	1.315	1.164
CSP-PCM + PHS storage	0.025	0.025	0.025	0.025	0.017	0.017	0.017	0.017
CW-STES + ICE storage	0	0	0	0	0.006	0.006	0.006	0.006
HW-STES storage	0.001	0.001	0.001	0.001	0.040	0.040	0.040	0.040
UTES storage	0.002	0.002	0.002	0.002	0.210	0.210	0.210	0.210
Heat pumps for filling district heating/cooling	0.010	0.010	0.010	0.010	0.108	0.108	0.108	0.108
Non-grid H_2 production/compression/storage	0.344	0.400	0.348	0.408	0.551	1.925	0.585	2.178
Total LCOE (¢/kWh-all-energy)	**8.468**	**8.373**	**8.376**	**8.385**	**10.851**	**11.316**	**11.060**	**12.577**
LCOE (¢/kWh-replacing BAU electricity)	8.106	7.955	8.010	7.959	9.932	9.022	10.106	10.030
GW annual avg. end-use demand (Table S8)	16.7	16.7	16.7	16.7	41.0	41.0	41.0	41.0
TWh/y end-use demand (GW x 8,760 h/y)	146	146	146	146	359	359	359	359
Annual energy cost ($billion/y)	**12.4**	**12.3**	**12.3**	**12.3**	**39.0**	**40.7**	**39.7**	**45.2**
% rise in LCOE & annual cost if 1.5x battery cost	1.15	0.03	0.05	0	8.13	1.51	2.82	0
	Russia region				South America			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.936	0.936	0.936	0.936	2.616	2.616	2.616	2.616
Cap cost generators-storage-H_2-HVDC ($tril)	**1.317**	**1.317**	**1.317**	**1.317**	**3.124**	**3.124**	**3.124**	**3.124**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.216	0.216	0.216	0.216	0.209	0.209	0.209	0.209
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	2.953	2.953	2.953	2.953	4.777	4.777	4.777	4.777
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.004	0.004	0.004	0.004	0.028	0.028	0.028	0.028
LI battery storage	0	0	0	0	0	0	0	0
Grid H_2 production/compression/storage/fuel cell	0	0	0	0	0	0	0	0
CSP-PCM + PHS storage	0.005	0.005	0.005	0.005	0.020	0.020	0.020	0.020
CW-STES + ICE storage	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
HW-STES storage	0.029	0.029	0.029	0.029	0.008	0.008	0.008	0.008
UTES storage	0.047	0.047	0.047	0.047	0.003	0.003	0.003	0.003
Heat pumps for filling district heating/cooling	0.057	0.057	0.057	0.057	0.020	0.020	0.020	0.020

Non-grid H_2 production/compression/storage	0.666	0.666	0.666	0.666	0.400	0.400	0.400	0.400
Total LCOE (¢/kWh-all-energy)	**7.405**	**7.405**	**7.405**	**7.405**	**8.893**	**8.893**	**8.893**	**8.893**
LCOE (¢/kWh-replacing BAU electricity)	6.567	6.567	6.567	6.567	8.439	8.439	8.439	8.439
GW annual avg. end-use demand (Table S8)	268.3	268.3	268.3	268.3	468.7	468.7	468.7	468.7
TWh/y end-use demand (GW x 8,760 h/y)	2,350	2,350	2,350	2,350	4,106	4,106	4,106	4,106
Annual energy cost ($billion/y)	**174.0**	**174.0**	**174.0**	**174.0**	**365.1**	**365.1**	**365.1**	**365.1**
% rise in LCOE & annual cost if 1.5x battery cost	0	0	0	0	0	0	0	0

	Southeast Asia				South Korea			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	6.295	6.295	6.295	6.648	1.460	1.460	1.460	1.698
Cap cost generators-storage-H_2-HVDC ($tril)	**7.183**	**7.214**	**7.195**	**8.361**	**1.830**	**1.734**	**1.746**	**2.003**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0.134	0.134	0.134	0.142	0	0	0	0
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	7.757	7.757	7.757	8.142	6.870	6.870	6.870	7.952
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.001	0.001	0.001	0.001	0.030	0.030	0.030	0.030
LI battery storage	0.510	0.438	0.386	0	1.598	0.392	0.332	0
Grid H_2 production/compression/storage/fuel cell	0	0.106	0.144	0.800	0	0.309	0.870	0.526
CSP-PCM + PHS storage	0.015	0.015	0.015	0.015	0.027	0.027	0.027	0.027
CW-STES + ICE storage	0.002	0.002	0.002	0.002	0	0	0	0
HW-STES storage	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002
UTES storage	0.011	0.011	0.011	0.011	0.015	0.015	0.015	0.015
Heat pumps for filling district heating/cooling	0.046	0.046	0.046	0.046	0.023	0.023	0.023	0.023
Non-grid H_2 production/compression/storage	0.580	0.599	0.599	1.995	0.862	1.231	0.862	1.749
Total LCOE (¢/kWh-all-energy)	**12.484**	**12.538**	**12.524**	**14.584**	**12.853**	**12.324**	**12.456**	**13.750**
LCOE (¢/kWh-replacing BAU electricity)	11.828	11.862	11.848	12.510	11.951	11.054	11.554	11.960
GW annual avg. end-use demand (Table S8)	584.6	584.6	584.6	584.6	154.4	154.4	154.4	154.4
TWh/y end-use demand (GW x 8,760 h/y)	5,121	5,121	5,121	5,121	1,352	1,352	1,352	1,352
Annual energy cost ($billion/y)	**639.3**	**642.1**	**641.3**	**746.8**	**173.8**	**166.7**	**168.5**	**185.9**
% rise in LCOE & annual cost if 1.5x battery cost	2.04	1.75	1.54	0	6.22	1.59	1.34	0
	Taiwan				United States			
	Case I	Case II	Case III	Case IV	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	0.620	0.620	0.620	0.755	4.946	4.946	4.946	5.634
Cap cost generators-storage-H_2-HVDC ($tril)	**0.983**	**0.802**	**0.839**	**0.970**	**6.667**	**6.476**	**6.456**	**7.758**
Components of total LCOE (¢/kWh-all-energy)								
Short-dist. transmission	1.050	1.050	1.050	1.050	1.050	1.050	1.050	1.050
Long-distance transmission	0	0	0	0	0.185	0.185	0.185	0.169
Distribution	2.375	2.375	2.375	2.375	2.375	2.375	2.375	2.375
Electricity generation	4.511	4.511	4.511	5.623	4.020	4.020	4.020	4.606
Additional hydro turbines	0	0	0	0	0	0	0	0
Geothermal + solar thermal heat generation	0.014	0.014	0.014	0.014	0.067	0.067	0.067	0.067
LI battery storage	3.081	0.751	0.880	0	0.704	0.383	0.376	0
Grid H_2 production/compression/storage/fuel cell	0	0.159	0.568	0.849	0	0.077	0.108	0.398
CSP-PCM + PHS storage	0.009	0.009	0.009	0.009	0.018	0.018	0.018	0.018
CW-STES + ICE storage	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
HW-STES storage	0.004	0.004	0.004	0.004	0.003	0.003	0.003	0.003
UTES storage	0.028	0.028	0.028	0.028	0.009	0.009	0.009	0.009
Heat pumps for filling district heating/cooling	0.063	0.063	0.063	0.063	0.046	0.046	0.046	0.046
Non-grid H_2 production/compression/storage	0.929	1.206	1.133	1.795	0.443	0.504	0.466	1.446
Total LCOE (¢/kWh-all-energy)	**12.065**	**10.172**	**10.636**	**11.812**	**8.920**	**8.738**	**8.725**	**10.189**
LCOE (¢/kWh-replacing BAU electricity)	11.041	8.870	9.409	9.922	8.405	8.163	8.186	8.671
GW annual avg. end-use demand (Table S8)	89.9	89.9	89.9	89.9	959.5	959.5	959.5	959.5
TWh/y end-use demand (GW x 8,760 h/y)	788	788	788	788	8,405	8,405	8,405	8,405
Annual energy cost ($billion/y)	**95.0**	**80.1**	**83.8**	**93.0**	**749.8**	**734.5**	**733.3**	**856.4**
% rise in LCOE & annual cost if 1.5x battery cost	12.8	3.7	4.1	0	3.94	2.19	2.16	0

Table S35. Summary of Costs by Region, Related to Table 1.
Same as Table S33, except for all regions combined.

	All regions			
	Case I	Case II	Case III	Case IV
Capital cost new generators only ($tril)	47.010	47.010	47.010	50.181
Cap cost generators-storage-H_2-HVDC ($tril)	**62.334**	**62.754**	**62.167**	**68.079**
Components of total LCOE (¢/kWh-all-energy)				
Short-dist. transmission	1.050	1.050	1.050	1.050
Long-distance transmission	0.172	0.173	0.173	0.172
Distribution	2.375	2.375	2.375	2.375
Electricity generation	3.897	3.897	3.897	4.175
Additional hydro turbines	0	0	0	0
Geothermal + solar thermal heat generation	0.078	0.078	0.078	0.078
LI battery storage	0.447	0.229	0.213	0
Grid H_2 production/compression/storage/fuel cell	0	0.096	0.183	0.275
CSP-PCM + PHS storage	0.021	0.021	0.021	0.022
CW-STES + ICE storage	0.002	0.002	0.002	0.002
HW-STES storage	0.008	0.008	0.008	0.008
UTES storage	0.056	0.056	0.056	0.056
Heat pumps for filling district heating/cooling	0.058	0.058	0.058	0.058
Non-grid H_2 production/compression/storage	0.611	0.822	0.682	1.227
Total LCOE (¢/kWh-all-energy)	**8.775**	**8.866**	**8.796**	**9.498**
LCOE (¢/kWh-replacing BAU electricity)	8.021	7.900	7.971	8.128
GW annual avg. end-use demand (Table S8)	8,970	8,970	8,970	8,970
TWh/y end-use demand (GW x 8,760 h/y)	78,578	78,578	78,578	78,578
Annual energy cost ($billion/y)	**6,896**	**6,966**	**6,912**	**7,464**
% rise in LCOE & annual cost if 1.5x battery cost	2.55	1.29	1.21	0

Table S36. Annual Cost Statistics, Related to Table 1.
regional and country annual-average end-use (a) BAU demand (same value in all four cases) and (b) WWS demand (same value in all four cases); (c) percentage difference between WWS and BAU demand; (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 in the base case (Case I); mean levelized private costs of all (e) BAU and (f) WWS energy in the base case (¢/kWh-all-energy-sectors, averaged between today and 2050); (g) mean WWS private (equals social) energy cost per year in the base case; (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) percentage difference between WWS and BAU private energy cost; and (m) percentage difference between WWS and BAU social energy cost in the base WWS case (Case I). All costs are in 2020 USD. H=8760 hours per year. Table 1 of the main text and Table S37 compare regional values among all cases, I-IV.

Region or country	(a)[1] 2050 BAU Annual-average end-use demand (GW)	(b)[1] 2050 WWS Annual-average end-use demand (GW)	(c) 2050 WWS minus BAU demand = (b-a)/a (%)	(d)[2] WWS mean total capital 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/y)	(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 (%)
Africa	**1,381.8**	**482.1**	**-65.1**	**3.627**	**10.09**	**8.63**	**364.5**	**1,221.9**	**3,982**	**1,782.6**	**6,987**	**-70.2**	**-94.8**
Algeria	142.7	43.8	-69.3	0.323	10.09	8.63	33.1	126.1	74.7	228.6	429	-73.7	-92.3
Angola	24.5	7.9	-67.9	0.061	10.09	8.63	6.0	21.7	94.0	32.7	148	-72.5	-96.0
Benin	11.0	2.6	-76.5	0.027	10.09	8.63	2.0	9.8	33.7	10.3	54	-79.9	-96.4
Botswana	5.4	2.1	-62.1	0.014	10.09	8.63	1.6	4.8	6.8	8.9	20	-67.6	-92.4
Cameroon	15.8	4.3	-72.6	0.038	10.09	8.63	3.3	14.0	68.9	12.8	96	-76.6	-96.6
Congo	4.6	1.3	-71.2	0.015	10.09	8.63	1.0	4.0	19.5	7.4	31	-75.4	-96.8
Congo, DR	35.8	8.5	-76.4	0.077	10.09	8.63	6.4	31.6	77.1	3.8	112	-79.8	-94.3
Côte d'Ivoire	16.6	5.1	-69.0	0.047	10.09	8.63	3.9	14.7	97.0	17.2	129	-73.5	-97.0
Egypt	186.8	88.8	-52.4	0.610	10.09	8.63	67.1	165.1	373.0	323.3	861	-59.3	-92.2
Equat. Guinea	6.6	4.1	-36.9	0.046	10.09	8.63	3.1	5.8	9.0	4.4	19	-46.0	-83.7
Eritrea	1.1	0.3	-72.4	0.002	10.09	8.63	0.2	1.0	10.9	0.9	13	-76.4	-98.2
Ethiopia	76.9	18.0	-76.5	0.123	10.09	8.63	13.6	68.0	243.5	23.1	335	-79.9	-95.9
Gabon	11.8	7.3	-38.7	0.081	10.09	8.63	5.5	10.5	8.5	4.4	23	-47.6	-76.6
Ghana	20.7	8.4	-59.6	0.078	10.09	8.63	6.3	18.3	83.4	21.3	123	-65.5	-94.9
Kenya	37.1	10.4	-71.9	0.076	10.09	8.63	7.9	32.8	46.7	25.1	105	-76.0	-92.5
Libya	31.4	13.2	-58.0	0.114	10.09	8.63	10.0	27.8	20.0	65.9	114	-64.1	-91.2
Morocco	44.6	19.4	-56.5	0.137	10.09	8.63	14.7	39.4	57.1	93.6	190	-62.8	-92.3
Mozambique	12.7	5.3	-58.4	0.034	10.09	8.63	4.0	11.2	36.3	11.7	59	-64.4	-93.3
Namibia	5.1	1.9	-62.1	0.015	10.09	8.63	1.5	4.5	6.2	5.6	16	-67.6	-91.1
Niger	6.3	1.6	-75.0	0.013	10.09	8.63	1.2	5.5	63.1	3.0	72	-78.6	-98.3
Nigeria	294.0	70.6	-76.0	0.588	10.09	8.63	53.4	260.0	1,972	127.0	2,358	-79.5	-97.7
Senegal	6.9	2.6	-61.7	0.019	10.09	8.63	2.0	6.1	28.6	12.4	47	-67.2	-95.8
South Africa	234.2	103.2	-55.9	0.707	10.09	8.63	78.0	207.1	118.2	626.4	952	-62.3	-91.8
South Sudan	1.4	0.4	-72.5	0.003	10.09	8.63	0.3	1.2	34.2	1.5	37	-76.5	-99.2
Sudan	32.0	11.2	-65.0	0.080	10.09	8.63	8.5	28.3	215.3	27.0	271	-70.1	-96.9
Tanzania	38.1	11.4	-70.0	0.096	10.09	8.63	8.7	33.7	73.6	16.9	124	-74.3	-93.0
Togo	4.5	1.2	-73.9	0.012	10.09	8.63	0.9	4.0	18.1	3.6	26	-77.6	-96.5
Tunisia	30.0	10.7	-64.4	0.079	10.09	8.63	8.1	26.5	25.5	40.6	93	-69.5	-91.3
Zambia	21.9	10.2	-53.2	0.072	10.09	8.63	7.7	19.3	49.3	9.5	78	-60.0	-90.1
Zimbabwe	21.5	6.3	-70.6	0.042	10.09	8.63	4.8	19.0	18.7	13.8	51	-74.8	-90.7
Australia	**208.8**	**92.3**	**-55.8**	**0.618**	**10.28**	**8.45**	**68.3**	**188.0**	**34.6**	**399.5**	**622**	**-63.7**	**-89.0**
Canada	**442.5**	**170.3**	**-61.5**	**0.654**	**8.03**	**6.57**	**98.1**	**311.3**	**42.3**	**518.3**	**872**	**-68.5**	**-88.8**
Central America	**378.2**	**156.5**	**-58.6**	**1.445**	**10.49**	**10.85**	**148.8**	**347.6**	**323.5**	**588.9**	**1,260**	**-57.2**	**-88.2**
Costa Rica	8.6	3.9	-55.1	0.029	10.49	10.85	3.7	7.9	6.6	8.9	23	-53.5	-84.3
El Salvador	5.5	2.4	-56.5	0.019	10.49	10.85	2.3	5.1	7.4	7.1	20	-55.0	-88.3
Guatemala	20.2	5.8	-71.2	0.051	10.49	10.85	5.5	18.6	32.0	21.1	72	-70.2	-92.3

Honduras	8.2	3.0	-62.9	0.034	10.49	10.85	2.9	7.5	10.7	10.3	28	-61.6	-89.9
Mexico	312.5	133.7	-57.2	1.226	10.49	10.85	127.1	287.1	252.4	524.1	1,064	-55.7	-88.0
Nicaragua	4.7	1.6	-65.1	0.018	10.49	10.85	1.6	4.3	8.3	5.8	18	-63.9	-91.5
Panama	18.5	6.0	-67.4	0.067	10.49	10.85	5.7	17.0	6.2	11.6	35	-66.3	-83.5
Central Asia	**446.5**	**166.9**	**-62.6**	**1.076**	**10.30**	**7.95**	**116.3**	**402.7**	**1,011**	**699.6**	**2,114**	**-71.1**	**-94.5**
Kazakhstan	87.2	33.6	-61.4	0.201	10.30	7.95	23.4	78.6	91.5	235.7	406	-70.2	-94.2
Kyrgyz Rep.	7.3	3.4	-53.3	0.015	10.30	7.95	2.4	6.6	16.0	10.1	33	-63.9	-92.7
Pakistan	233.1	96.0	-58.8	0.667	10.30	7.95	66.9	210.2	795.7	288.5	1,294	-68.2	-94.8
Tajikistan	5.8	3.4	-40.4	0.008	10.30	7.95	2.4	5.2	19.6	7.6	32	-53.9	-92.6
Turkmenistan	40.0	9.2	-77.0	0.059	10.30	7.95	6.4	36.0	20.2	76.9	133	-82.2	-95.2
Uzbekistan	73.2	21.2	-71.0	0.127	10.30	7.95	14.8	66.0	68.3	80.7	215	-77.6	-93.1
China region	**5,076.3**	**2,423.9**	**-52.3**	**14.445**	**9.55**	**8.16**	**1,733.1**	**4,248.4**	**10,757**	**8,495.7**	**23,501**	**-59.2**	**-92.6**
China	4,970.5	2,382.8	-52.1	14.089	9.55	8.16	1,703.7	4,159.8	10,602	8,338.2	23,100	-59.0	-92.6
Hong Kong	82.7	29.8	-63.9	0.291	9.55	8.16	21.3	69.2	54.7	56.8	181	-69.2	-88.2
Korea, DPR	13.3	7.4	-44.8	0.040	9.55	8.16	5.3	11.2	81.8	54.4	147	-52.8	-96.4
Mongolia	9.9	3.9	-60.2	0.025	9.55	8.16	2.8	8.3	18.3	46.4	73	-66.0	-96.2
Cuba	**15.8**	**9.0**	**-43.0**	**0.103**	**11.64**	**12.15**	**9.6**	**16.1**	**37.5**	**30.9**	**84**	**-40.5**	**-88.7**
Europe	**2,287.7**	**958.3**	**-58.1**	**5.785**	**10.01**	**8.46**	**710.0**	**2,005.4**	**1,772**	**2,858.0**	**6,635**	**-64.6**	**-89.3**
Albania	4.4	2.1	-53.1	0.010	10.01	8.46	1.5	3.9	14.3	4.8	23	-60.3	-93.3
Austria	47.9	20.9	-56.4	0.113	10.01	8.46	15.5	42.0	20.3	53.3	116	-63.1	-86.6
Belarus	37.5	12.8	-65.8	0.083	10.01	8.46	9.5	32.9	50.2	56.3	139	-71.1	-93.2
Belgium	73.3	30.5	-58.4	0.188	10.01	8.46	22.6	64.3	26.1	76.9	167	-64.8	-86.5
Bosnia-Herzeg.	9.0	3.8	-57.7	0.022	10.01	8.46	2.8	7.9	29.1	28.5	65	-64.2	-95.7
Bulgaria	22.4	10.0	-55.3	0.072	10.01	8.46	7.4	19.6	38.2	36.8	95	-62.2	-92.2
Croatia	14.8	6.0	-59.2	0.039	10.01	8.46	4.5	13.0	21.5	16.3	51	-65.5	-91.2
Cyprus	4.2	1.8	-56.6	0.013	10.01	8.46	1.4	3.7	3.6	6.3	14	-63.3	-90.0
Czech Rep.	43.9	18.0	-59.0	0.112	10.01	8.46	13.3	38.5	32.0	77.8	148	-65.4	-91.0
Denmark	26.1	9.7	-62.9	0.053	10.01	8.46	7.2	22.9	11.7	22.9	57	-68.6	-87.5
Estonia	6.0	2.1	-65.0	0.015	10.01	8.46	1.6	5.3	2.8	13.6	22	-70.4	-92.8
Finland	42.6	22.3	-47.7	0.141	10.01	8.46	16.5	37.3	6.0	32.0	75	-55.8	-78.1
France	248.6	111.6	-55.1	0.701	10.01	8.46	82.7	217.9	115.0	231.7	565	-62.0	-85.4
Germany	361.0	154.6	-57.2	0.870	10.01	8.46	114.5	316.5	223.0	517.4	1,057	-63.8	-89.2
Gibraltar	6.0	1.5	-75.5	0.020	10.01	8.46	1.1	5.2	0.2	0.5	6	-79.3	-81.9
Greece	32.5	13.0	-60.1	0.078	10.01	8.46	9.6	28.5	42.0	48.3	119	-66.3	-91.9
Hungary	31.7	12.6	-60.3	0.091	10.01	8.46	9.3	27.8	37.8	37.5	103	-66.5	-90.9
Ireland	18.9	8.0	-57.6	0.050	10.01	8.46	5.9	16.5	9.8	26.9	53	-64.1	-88.8
Italy	215.7	83.6	-61.2	0.517	10.01	8.46	62.0	189.1	188.7	244.1	622	-67.2	-90.0
Kosovo	3.0	1.4	-54.3	0.010	10.01	8.46	1.0	2.6	1.7	7.2	12	-61.4	-91.2
Latvia	8.1	3.2	-60.2	0.020	10.01	8.46	2.4	7.1	10.0	7.1	24	-66.3	-90.1
Lithuania	12.6	5.0	-60.4	0.038	10.01	8.46	3.7	11.0	14.0	11.7	37	-66.6	-90.0
Luxembourg	6.5	2.5	-62.2	0.016	10.01	8.46	1.8	5.7	1.7	7.2	15	-68.0	-87.5
Macedonia	3.8	1.9	-49.9	0.012	10.01	8.46	1.4	3.4	11.0	7.6	22	-57.7	-93.5
Malta	5.6	1.7	-69.9	0.016	10.01	8.46	1.2	4.9	1.1	0.9	7	-74.5	-82.0
Moldova	6.0	2.3	-61.8	0.016	10.01	8.46	1.7	5.3	5.9	7.8	19	-67.7	-91.0
Montenegro	1.6	0.8	-50.0	0.004	10.01	8.46	0.6	1.4	3.9	3.7	9	-57.7	-93.5
Netherlands	104.5	41.6	-60.2	0.259	10.01	8.46	30.8	91.6	43.8	115.2	251	-66.4	-87.7
Norway	47.3	20.7	-56.3	0.062	10.01	8.46	15.3	41.4	7.7	35.3	84	-63.1	-81.9
Poland	126.7	48.9	-61.4	0.336	10.01	8.46	36.3	111.0	131.4	233.9	476	-67.3	-92.4
Portugal	30.2	13.5	-55.3	0.076	10.01	8.46	10.0	26.4	15.6	35.7	78	-62.2	-87.1
Romania	48.4	18.9	-60.9	0.111	10.01	8.46	14.0	42.4	141.8	66.8	251	-67.0	-94.4
Serbia	18.8	8.9	-53.0	0.059	10.01	8.46	6.6	16.5	37.6	60.1	114	-60.3	-94.3
Slovakia	20.0	8.6	-57.0	0.051	10.01	8.46	6.4	17.5	16.6	26.5	61	-63.6	-89.5
Slovenia	8.3	3.9	-53.5	0.023	10.01	8.46	2.9	7.3	5.2	11.3	24	-60.7	-88.0
Spain	166.0	69.0	-58.4	0.402	10.01	8.46	51.2	145.5	88.8	190.9	425	-64.8	-88.0
Sweden	55.4	30.3	-45.3	0.154	10.01	8.46	22.5	48.6	11.6	33.0	93	-53.8	-75.9
Switzerland	32.1	14.3	-55.2	0.064	10.01	8.46	10.6	28.1	13.9	29.0	71	-62.2	-85.0
Ukraine	104.2	48.2	-53.7	0.304	10.01	8.46	35.7	91.3	183.2	166.9	441	-60.9	-91.9
United King.	232.4	87.9	-62.2	0.568	10.01	8.46	65.1	203.7	153.3	268.5	626	-68.0	-89.6
Haiti region	**19.1**	**7.6**	**-60.3**	**0.055**	**10.90**	**8.72**	**5.8**	**18.3**	**36.2**	**30.7**	**85**	**-68.2**	**-93.2**
Dominican Rep	14.0	6.3	-55.1	0.043	10.90	8.72	4.8	13.4	20.3	27.1	61	-64.1	-92.1
Haiti	5.1	1.3	-74.3	0.012	10.90	8.72	1.0	4.9	15.9	3.6	24	-79.5	-95.9
Iceland	**5.6**	**3.2**	**-42.9**	**0.0029**	**7.51**	**7.07**	**2.0**	**3.7**	**0.4**	**2.9**	**7**	**-47.1**	**-72.0**

India region	**2,010.5**	**1,006.8**	**-49.9**	**6.892**	**9.88**	**8.17**	**720.9**	**1,739.6**	**9,472**	**3,756.5**	**14,968**	**-58.6**	**-95.2**
Bangladesh	82.7	35.8	-56.7	0.283	9.88	8.17	25.6	71.5	523.1	130.5	725	-64.2	-96.5
India	1,870.8	951.6	-49.1	6.463	9.88	8.17	681.3	1,618.7	8,755	3,571.0	13,944	-57.9	-95.1
Nepal	28.5	7.9	-72.2	0.065	9.88	8.17	5.7	24.7	99.9	19.4	144	-77.0	-96.1
Sri Lanka	28.6	11.5	-59.6	0.081	9.88	8.17	8.3	24.7	94.0	35.6	154	-66.5	-94.6
Israel	**26.1**	**12.8**	**-51.0**	**0.141**	**11.21**	**12.46**	**13.9**	**25.6**	**15.7**	**50.3**	**92**	**-45.6**	**-84.8**
Jamaica	**5.5**	**2.6**	**-53.7**	**0.025**	**11.38**	**10.57**	**2.4**	**5.5**	**3.4**	**7.4**	**16**	**-57.0**	**-85.5**
Japan	**355.4**	**186.3**	**-47.6**	**1.311**	**10.48**	**9.39**	**153.2**	**326.3**	**261.5**	**678.1**	**1,266**	**-53.0**	**-87.9**
Mauritius	**5.2**	**1.9**	**-63.2**	**0.018**	**10.64**	**11.75**	**1.9**	**4.8**	**3.7**	**5.5**	**14**	**-59.4**	**-86.1**
Mideast	**1,520.1**	**706.5**	**-53.5**	**4.523**	**11.39**	**8.05**	**498.3**	**1,517.3**	**858.4**	**2,900.1**	**5,276**	**-67.2**	**-90.6**
Armenia	4.8	1.5	-68.6	0.008	11.39	8.05	1.1	4.8	10.1	5.0	20	-77.8	-94.7
Azerbaijan	19.1	6.4	-66.8	0.044	11.39	8.05	4.5	19.1	37.8	30.6	87	-76.5	-94.9
Bahrain	17.6	9.6	-45.5	0.054	11.39	8.05	6.8	17.6	2.1	41.9	62	-61.5	-89.0
Iran	444.0	186.3	-58.0	1.253	11.39	8.05	131.4	443.2	171.2	828.9	1,443	-70.4	-90.9
Iraq	62.1	23.1	-62.7	0.176	11.39	8.05	16.3	61.9	90.6	233.4	386	-73.6	-95.8
Jordan	15.8	6.9	-56.4	0.043	11.39	8.05	4.9	15.7	11.3	33.5	60	-69.2	-92.0
Kuwait	57.4	23.5	-59.0	0.143	11.39	8.05	16.6	57.3	12.6	116.9	187	-71.0	-91.1
Lebanon	13.2	6.2	-53.4	0.040	11.39	8.05	4.3	13.2	9.0	32.4	55	-67.1	-92.0
Oman	59.9	26.0	-56.6	0.167	11.39	8.05	18.3	59.8	8.3	109.6	178	-69.4	-89.7
Qatar	78.8	33.2	-57.9	0.191	11.39	8.05	23.4	78.7	3.6	125.8	208	-70.3	-88.8
Saudi Arabia	349.0	183.6	-47.4	1.189	11.39	8.05	129.5	348.4	124.7	725.8	1,199	-62.8	-89.2
Syria	14.4	6.3	-55.9	0.041	11.39	8.05	4.5	14.3	47.5	34.4	96	-68.8	-95.4
Turkiye	173.7	81.3	-53.2	0.515	11.39	8.05	57.3	173.3	229.7	306.1	709	-66.9	-91.9
UAE	205.6	110.9	-46.0	0.645	11.39	8.05	78.2	205.2	11.2	262.9	479	-61.9	-83.7
Yemen	4.8	1.7	-63.5	0.013	11.39	8.05	1.2	4.8	88.8	12.9	106	-74.2	-98.8
New Zealand	**32.4**	**16.7**	**-48.5**	**0.098**	**8.11**	**8.47**	**12.4**	**23.0**	**5.2**	**35.7**	**64**	**-46.2**	**-80.6**
Philippines	**93.9**	**41.0**	**-56.3**	**0.412**	**10.19**	**10.85**	**39.0**	**83.8**	**677.3**	**194.3**	**955**	**-53.5**	**-95.9**
Russia region	**787.8**	**268.3**	**-65.9**	**1.317**	**10.18**	**7.40**	**174.0**	**702.4**	**601.8**	**1,248.3**	**2,552**	**-75.2**	**-93.2**
Georgia	8.6	3.6	-58.0	0.012	10.18	7.40	2.3	7.7	31.1	11.4	50	-69.5	-95.3
Russia	779.2	264.7	-66.0	1.304	10.18	7.40	171.7	694.7	570.6	1,236.8	2,502	-75.3	-93.1
South America	**1,090.8**	**468.7**	**-57.0**	**3.124**	**8.44**	**8.89**	**365.1**	**806.4**	**749.8**	**1,161.3**	**2,718**	**-54.7**	**-86.6**
Argentina	144.4	51.1	-64.6	0.252	8.44	8.89	39.8	106.8	98.3	198.1	403	-62.7	-90.1
Bolivia	18.3	5.2	-71.7	0.032	8.44	8.89	4.0	13.5	22.7	24.3	61	-70.2	-93.4
Brazil	591.3	272.1	-54.0	1.910	8.44	8.89	212.0	437.1	352.7	494.7	1,285	-51.5	-83.5
Chile	67.5	34.9	-48.3	0.170	8.44	8.89	27.2	49.9	38.6	97.1	186	-45.5	-85.4
Colombia	70.5	27.5	-61.0	0.209	8.44	8.89	21.4	52.1	72.8	86.0	211	-58.9	-89.9
Curacao	5.2	1.4	-72.8	0.011	8.44	8.89	1.1	3.9	0.1	5.9	10	-71.3	-88.7
Ecuador	28.0	10.0	-64.2	0.070	8.44	8.89	7.8	20.7	16.1	40.4	77	-62.3	-89.9
Paraguay	12.9	5.7	-55.4	0.015	8.44	8.89	4.5	9.5	12.4	8.4	30	-53.0	-85.2
Peru	47.4	18.7	-60.5	0.137	8.44	8.89	14.6	35.1	77.0	55.9	168	-58.4	-91.3
Suriname	1.2	0.5	-59.9	0.003	8.44	8.89	0.4	0.9	1.6	2.0	4	-57.8	-91.6
Trinidad/Tob.	15.4	8.5	-44.8	0.051	8.44	8.89	6.6	11.4	2.6	32.5	46	-41.8	-85.8
Uruguay	10.0	5.1	-48.6	0.025	8.44	8.89	4.0	7.4	5.2	6.5	19	-45.9	-79.2
Venezuela	78.8	28.0	-64.5	0.239	8.44	8.89	21.8	58.2	49.8	109.3	217	-62.6	-90.0
Southeast Asia	**1,300.7**	**584.6**	**-55.1**	**7.183**	**10.39**	**12.48**	**639.3**	**1,183.3**	**1,936**	**2,046.6**	**5,166**	**-46.0**	**-87.6**
Brunei	5.2	1.5	-71.5	0.020	10.39	12.48	1.6	4.8	0.5	9.0	14	-65.7	-88.6
Cambodia	17.3	6.8	-60.5	0.059	10.39	12.48	7.4	15.7	40.4	21.3	77	-52.6	-90.4
Indonesia	423.9	191.9	-54.7	1.883	10.39	12.48	209.8	385.6	1,038	806.9	2,231	-45.6	-90.6
Lao PDR	7.6	2.8	-63.2	0.004	10.39	12.48	3.0	6.9	31.6	8.8	47	-55.8	-93.6
Malaysia	169.0	80.7	-52.3	1.081	10.39	12.48	88.2	153.7	95.6	320.9	570	-42.6	-84.5
Myanmar	44.7	15.7	-65.0	0.113	10.39	12.48	17.1	40.7	197.5	62.3	300	-57.9	-94.3
Singapore	216.6	69.7	-67.8	1.839	10.39	12.48	76.3	197.0	33.2	68.9	299	-61.3	-74.5
Thailand	257.5	116.9	-54.6	1.173	10.39	12.48	127.9	234.3	289.6	354.8	879	-45.4	-85.4
Vietnam	159.1	98.6	-38.0	1.011	10.39	12.48	107.9	144.7	209.1	393.8	748	-25.5	-85.6
South Korea	**304.9**	**154.4**	**-49.4**	**1.830**	**10.53**	**12.85**	**173.8**	**281.2**	**104.4**	**526.9**	**913**	**-38.2**	**-81.0**
Taiwan	**165.3**	**89.9**	**-45.6**	**0.983**	**10.60**	**12.07**	**95.0**	**153.5**	**85.9**	**357.0**	**596**	**-38.1**	**-84.1**
United States	**2,397.8**	**959.5**	**-60.0**	**6.667**	**10.42**	**8.92**	**749.8**	**2,188.6**	**829.7**	**3,381.7**	**6,400**	**-65.7**	**-88.3**
All regions	**20,359**	**8,970.1**	**-55.9**	**62.3**	**9.98**	**8.78**	**6,895**	**17,805**	**33,601**	**31,757**	**83,163**	**-61.3**	**-91.7**

[1]From Tables S4-S6.

[2]The total capital cost includes the capital cost of new WWS electricity and heat generators; new electricity, heat, cold, and hydrogen storage equipment; hydrogen electrolyzers and compressors; heat pumps for district heating/cooling; and long-distance (HVDC) transmission lines. Capital costs are an average between 2020 and 2050.

[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 and is an average between 2020 and 2050.

[4]The WWS cost per unit energy is for all energy, which is almost all electricity (plus a small amount of direct heat). It is an average between 2020 and 2050.

[5]The annual private cost of WWS or BAU energy equals the cost per unit energy from Column (f) or (e), respectively, multiplied by the energy consumed per year, which equals the end-use demand 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 S38, Column (a), multiplied by 90% (the estimated percentage of total air pollution mortalities that are due to energy) and by a statistical cost of life calculated for each country, calculated as in ref. [S14], and a multiplier of 1.15 for morbidity and another multiplier of 1.1 for non-health impacts [S14]. See ref. [S3] for values in each country and Note S8 for a discussion

[7]The 2050 annual BAU climate cost equals the 2050 CO_2e emissions from Table S38, Column (b), multiplied by the mean social cost of carbon in 2050 from Table S38, Column (f) (in 2020 USD), which is updated from values in ref. [S14], which were in 2013 USD. See Note S8 for a discussion.

Table S37. Annual Cost Statistics, Related to Table 1.

(a)-(d) 2050 BAU annual private energy cost, health cost, climate cost, and total social cost, respectively for each region, from Table S36; (e)-(g) Case I WWS annual private (=social) energy cost from Table S36, percent difference between Case I WWS and BAU private costs, and percent difference between Case I WWS and BAU social costs, respectively; (h)-(j) same as (e)-(j), except for Case II; (k)-(m) same as (e)-(j), except for Case III; and (n)-(p) same as (e)-(j), except for Case IV. All costs are in 2020 USD.

	All cases				Case I			Case II		
Region	(a) BAU mean annual all-energy private cost ($bil/y)	(b) BAU mean annual BAU health cost ($bil/y)	(c) BAU mean annual climate cost ($bil/y)	(d) BAU mean annual BAU total social cost =a+b+c ($bil/y)	(e) WWS mean annual all-energy private = social cost ($bil/y)	(f) WWS minus BAU private energy cost= (e-a)/a (%)	(g) WWS minus BAU social energy cost= (e-d)/d (%)	(h) WWS mean annual all-energy private = social cost ($bil/y)	(i) WWS minus BAU private energy cost= (h-a)/a (%)	(j) WWS minus BAU social energy cost= (h-d)/d (%)
Africa	1,222	3,982	1,783	6,987	364.5	-70.2	-94.8	361.2	-70.4	-94.8
Australia	188.0	34.6	399.5	622.1	68.3	-63.7	-89.0	67.7	-64.0	-89.1
Canada	311.3	42.3	518.3	871.8	98.1	-68.5	-88.8	98.1	-68.5	-88.8
Central America	347.6	323.5	588.9	1,260	148.8	-57.2	-88.2	139.5	-59.9	-88.9
Central Asia	402.7	1,011	699.6	2,114	116.3	-71.1	-94.5	117.7	-70.8	-94.4
China region	4,248	10,757	8,496	23,501	1,733	-59.2	-92.6	1,838	-56.7	-92.2
Cuba	16.1	37.5	30.9	84.4	9.57	-40.5	-88.7	9.32	-42.0	-89.0
Europe	2,005	1,772	2,858	6,635	710.0	-64.6	-89.3	735.1	-63.3	-88.9
Haiti region	18.3	36.2	30.7	85.1	5.81	-68.2	-93.2	5.78	-68.4	-93.2
Iceland	3.7	0.4	2.9	7.0	1.96	-47.1	-72.0	1.96	-47.1	-72.0
India region	1,740	9,472	3,756	14,968	720.9	-58.6	-95.2	710.2	-59.2	-95.3
Israel	25.6	15.7	50.3	91.7	13.9	-45.6	-84.8	12.3	-52.1	-86.6
Jamaica	5.5	3.4	7.4	16.3	2.37	-57.0	-85.5	2.34	-57.6	-85.7
Japan	326.3	261.5	678.1	1,266	153.2	-53.0	-87.9	152.1	-53.4	-88.0
Mauritius	4.8	3.7	5.5	14.0	1.95	-59.4	-86.1	2.01	-58.1	-85.6
Middle East	1,517	858.4	2,900	5,276	498.3	-67.2	-90.6	497.3	-67.2	-90.6
New Zealand	23.0	5.2	35.7	63.9	12.4	-46.2	-80.6	12.3	-46.8	-80.8
Philippines	83.8	677.3	194.3	955.5	39.0	-53.5	-95.9	40.7	-51.5	-95.7
Russia region	702.4	601.8	1,248	2,552	174.0	-75.2	-93.2	174.0	-75.2	-93.2
South America	806.4	749.8	1,161	2,718	365.1	-54.7	-86.6	365.1	-54.7	-86.6
Southeast Asia	1,183	1,936	2,047	5,166	639.3	-46.0	-87.6	642.1	-45.7	-87.6
South Korea	281.2	104.4	526.9	912.5	173.8	-38.2	-81.0	166.7	-40.7	-81.7
Taiwan	153.5	85.9	357.0	596.4	95.0	-38.1	-84.1	80.1	-47.8	-86.6
United States	2,189	829.7	3,382	6,400	749.8	-65.7	-88.3	734.5	-66.4	-88.5
All regions	**17,805**	**33,601**	**31,757**	**83,163**	**6,895**	**-61.27**	**-91.71**	**6,966**	**-60.87**	**-91.62**

Energy costs are for all components in Tables S33-S35: new electricity and heat generation, short- and long-distance (HVDC) transmission and distribution, battery storage, concentrated solar power with storage, pumped hydropower storage, cold water storage, ice storage, hot water storage, underground thermal energy storage, heat pumps for district heating and cooling, and hydrogen production, storage, and use (electrolyzers, rectifiers, storage tanks, water, dispensing, cooling, and fuel cells).

Tables S25-S32 give cost parameters. A social discount rate of 2 (1-3)% is used.

The four cases are defined as follows: Case I (baseline): No hydrogen is used for grid electricity but hydrogen is used for non-grid purposes (steel and ammonia manufacturing and long-distance transport); Case II: Hydrogen is used for both grid and non-grid purposes, but hydrogen rectifiers, electrolyzers, compressors, and storage tanks are shared for both purposes, and fuel cells are used to produce grid electricity when needed from the communal storage; Case III: Same as Case II, except that unique rectifiers, electrolyzers, compressors, and storage tanks are used for grid versus non-grid H_2, and fuel cells are used to produce grid electricity when needed from the grid-hydrogen storage; and Case IV: Same as Case II, except that no batteries are include (hydrogen rectifiers, electrolyzers, compressors, and storage are communal).

Table S37, cont.

Region	Case III			Case IV		
	(k) WWS mean annual all-energy private = social cost ($bil/y)	(l) WWS minus BAU private energy cost= (h-a)/a (%)	(m) WWS minus BAU social energy cost= (h-d)/d (%)	(n) WWS mean annual all-energy private = social cost ($bil/y)	(o) WWS minus BAU private energy cost= (h-a)/a (%)	(p) WWS minus BAU social energy cost= (h-d)/d (%)
Africa	366.0	-70.0	-94.8	416.0	-66.0	-94.0
Australia	75.6	-59.8	-87.8	83.0	-55.9	-86.7
Canada	98.1	-68.5	-88.8	98.1	-68.5	-88.8
Central America	142.7	-59.0	-88.7	150.0	-56.9	-88.1
Central Asia	117.4	-70.9	-94.4	119.7	-70.3	-94.3
China region	1,754	-58.7	-92.5	1,873	-55.9	-92.0
Cuba	9.34	-41.9	-88.9	11.8	-26.5	-86.0
Europe	709.9	-64.6	-89.3	745.8	-62.8	-88.8
Haiti region	5.91	-67.7	-93.1	8.40	-54.0	-90.1
Iceland	1.96	-47.1	-72.0	1.96	-47.1	-72.0
India region	748.0	-57.0	-95.0	794.4	-54.3	-94.7
Israel	11.7	-54.4	-87.3	15.2	-40.8	-83.5
Jamaica	2.38	-56.7	-85.4	2.74	-50.3	-83.2
Japan	152.1	-53.4	-88.0	156.0	-52.2	-87.7
Mauritius	2.08	-56.6	-85.1	2.23	-53.5	-84.1
Middle East	496.7	-67.3	-90.6	507.0	-66.6	-90.4
New Zealand	12.3	-46.8	-80.8	12.3	-46.7	-80.8
Philippines	39.7	-52.6	-95.8	45.2	-46.1	-95.3
Russia region	174.0	-75.2	-93.2	174.0	-75.2	-93.2
South America	365.1	-54.7	-86.6	365.1	-54.7	-86.6
Southeast Asia	641.3	-45.8	-87.6	746.8	-36.9	-85.5
South Korea	168.5	-40.1	-81.5	185.9	-33.9	-79.6
Taiwan	83.8	-45.4	-86.0	93.0	-39.4	-84.4
United States	733.3	-66.5	-88.5	856.4	-60.9	-86.6
All regions	**6,912**	**-61.18**	**-91.69**	**7,464**	**-58.08**	**-91.03**

Table S38. Social Cost Information, Related to Table 1.
Regional (a) estimated air pollution mortalities per year in 2050-2052 due to all sources (about 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 in the WWS base case here (Case I); (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.

Region or country	(a)[1] 2050 BAU air pollution mortal-ities (deaths/y)	(b)[2] 2050 BAU CO_2e (Mton-ne/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)
Africa	**1,173,737**	**3,192**	**114.2**	**383**	**1,247**	**558**	**2,189**	**32.9**	**14.7**
Algeria	10,788	409	80.9	308	183	558	1,049	6.0	18.3
Angola	19,997	59	101.8	371	1,606	558	2,535	43.7	15.2
Benin	17,080	18	106.0	528	1,822	558	2,908	34.9	10.7
Botswana	940	16	97.5	301	424	558	1,283	14.2	18.7
Cameroon	25,940	23	142.7	610	3,007	558	4,175	49.8	9.2
Congo	4,535	13	75.8	308	1,482	559	2,349	48.6	18.3
Congo, DR	93,264	7	945.8	4,678	11,391	556	16,626	24.6	1.2
Côte d'Ivoire	33,702	31	126.5	478	3,157	558	4,193	66.7	11.8
Egypt	63,218	579	116.0	285	644	558	1,488	22.8	19.8
Equator. Guinea	919	8	397.3	736	1,140	559	2,435	15.6	7.7
Eritrea	6,912	2	134.3	569	6,410	560	7,539	113.7	9.9
Ethiopia	152,676	41	329.6	1,643	5,883	558	8,085	36.1	3.4
Gabon	1,054	8	694.3	1,325	1,080	558	2,963	8.2	4.2
Ghana	25,489	38	165.5	480	2,185	558	3,223	46.0	11.8
Kenya	17,759	45	175.2	730	1,039	558	2,328	14.4	7.7
Libya	2,943	118	84.4	235	169	558	963	7.3	24.0
Morocco	10,340	168	87.6	235	341	559	1,135	14.6	23.9
Mozambique	24,785	21	190.3	535	1,730	559	2,823	32.6	10.5
Namibia	961	10	146.0	451	624	559	1,634	14.0	12.5
Niger	52,061	5	221.3	1,036	11,795	558	13,389	114.9	5.4
Nigeria	417,387	227	234.8	1,144	8,676	559	10,379	76.6	4.9
Senegal	12,993	22	89.6	274	1,286	559	2,119	47.5	20.6
South Africa	18,075	1,122	69.5	185	105	558	848	5.8	30.5
South Sudan	19,243	3	103.3	439	12,393	559	13,391	284.9	12.9
Sudan	66,066	48	175.1	585	4,447	558	5,590	76.7	9.6
Tanzania	31,178	30	286.1	1,115	2,434	559	4,108	22.0	5.1
Togo	12,450	6	137.7	616	2,803	558	3,977	45.9	9.2
Tunisia	4,209	73	111.1	365	350	558	1,273	9.7	15.5
Zambia	15,983	17	455.1	1,137	2,897	559	4,593	25.7	5.0
Zimbabwe	10,790	25	193.9	771	758	559	2,087	9.9	7.3
Australia	**3,034**	**716**	**95.5**	**263**	**48**	**558**	**869**	**1.9**	**21.8**
Canada	**3,764**	**928**	**105.7**	**335**	**46**	**558**	**939**	**1.1**	**13.4**
Central America	**45,608**	**1,055**	**141.1**	**329**	**307**	**558**	**1,194**	**9.8**	**17.8**
Costa Rica	1,008	16	230.6	496	416	559	1,470	8.8	11.8
El Salvador	1,558	13	179.2	398	581	558	1,537	15.3	14.7
Guatemala	7,217	38	146.8	492	848	558	1,898	18.1	11.9
Honduras	3,162	18	156.3	407	581	558	1,546	15.0	14.4
Mexico	29,973	939	135.4	306	269	558	1,133	9.2	19.1
Nicaragua	1,908	10	150.4	416	792	558	1,766	20.0	14.1
Panama	782	21	277.3	822	300	558	1,680	3.8	7.1
Central Asia	**235,560**	**1,253**	**92.8**	**321**	**807**	**558**	**1,687**	**25.9**	**17.9**
Kazakhstan	7,774	422	55.5	186	217	558	961	12.0	30.9
Kyrgyz Republic	3,796	18	131.1	363	883	558	1,805	25.0	15.8

Pakistan	204,993	517	129.4	407	1,540	558	2,506	39.0	14.1
Tajikistan	5,315	14	176.9	384	1,446	559	2,389	38.8	15.0
Turkmenistan	2,073	138	46.5	262	147	558	967	5.8	22.0
Uzbekistan	11,609	145	102.2	456	472	558	1,487	10.7	12.6
China region	**1,134,535**	**15,212**	**113.9**	**279**	**707**	**558**	**1,545**	**24.2**	**19.1**
China	1,090,244	14,930	114.1	279	710	558	1,547	24.4	19.2
Hong Kong	3,982	102	209.8	680	538	558	1,776	7.6	7.8
Korea, DPR	37,703	97	54.0	115	839	559	1,512	70.0	46.6
Mongolia	2,606	83	33.8	99	221	559	879	21.2	53.7
Cuba	**4,851**	**55**	**173.2**	**291**	**679**	**559**	**1,528**	**27.2**	**22.3**
Europe	**179,603**	**5,119**	**138.7**	**392**	**346**	**558**	**1,296**	**8.8**	**14.3**
Albania	1,766	9	178.4	450	1,659	558	2,667	36.9	12.4
Austria	1,741	95	162.2	440	213	558	1,211	4.9	12.7
Belarus	5,001	101	94.1	326	497	558	1,381	15.3	17.1
Belgium	2,294	138	164.2	467	189	559	1,215	4.1	12.0
Bosnia-Herzeg.	3,661	51	55.3	155	571	559	1,284	36.9	36.1
Bulgaria	3,772	66	112.4	298	579	558	1,435	19.5	18.8
Croatia	1,966	29	153.8	446	741	559	1,745	16.6	12.5
Cyprus	280	11	120.1	327	318	558	1,203	9.7	17.1
Czech Rep.	3,217	139	95.6	276	229	558	1,064	8.3	20.2
Denmark	1,003	41	174.9	557	284	558	1,400	5.1	10.0
Estonia	298	24	63.7	216	116	559	891	5.4	25.9
Finland	544	57	288.4	652	106	558	1,315	1.6	8.6
France	10,527	415	199.3	525	277	558	1,360	5.3	10.6
Germany	19,077	926	123.6	342	241	558	1,141	7.0	16.4
Gibraltar	20	0.92	1,178.2	5,700	268	558	6,526	0.5	1.0
Greece	4,606	86	111.1	330	486	558	1,374	14.7	17.0
Hungary	4,162	67	139.2	415	564	559	1,538	13.6	13.5
Ireland	782	48	123.1	343	202	558	1,104	5.9	16.3
Italy	18,054	437	141.7	432	432	558	1,423	10.0	12.9
Kosovo	276	13	79.2	205	133	558	896	6.5	27.2
Latvia	878	13	187.9	558	787	558	1,902	14.1	10.0
Lithuania	1,346	21	175.6	525	669	559	1,753	12.7	10.6
Luxembourg	103	13	141.9	444	133	559	1,135	3.0	12.6
Macedonia	1,486	14	104.9	248	810	558	1,615	32.7	22.5
Malta	104	2	780.1	3,062	722	560	4,344	2.4	1.8
Moldova	1,384	14	121.2	375	418	558	1,352	11.2	14.9
Montenegro	481	7	88.6	210	589	558	1,357	28.1	26.6
Netherlands	3,352	206	149.3	444	212	558	1,215	4.8	12.6
Norway	567	63	241.9	655	121	558	1,334	1.9	8.5
Poland	14,360	419	86.6	265	314	558	1,137	11.8	21.1
Portugal	1,656	64	156.5	414	245	558	1,217	5.9	13.5
Romania	13,080	120	117.1	354	1,185	558	2,097	33.5	15.8
Serbia	4,208	108	61.0	154	350	558	1,062	22.8	36.4
Slovakia	1,732	47	134.5	369	349	558	1,277	9.5	15.1
Slovenia	533	20	141.0	359	258	558	1,175	7.2	15.6
Spain	8,585	342	149.6	426	260	558	1,244	6.1	13.1
Sweden	979	59	380.6	823	196	559	1,578	2.4	6.8
Switzerland	1,087	52	204.7	541	267	558	1,366	4.9	10.3
Ukraine	26,812	299	119.6	305	613	558	1,477	20.1	18.3
United Kingdom	13,823	481	135.3	423	319	558	1,300	7.5	13.2
Haiti region	**13,695**	**55**	**105.8**	**333**	**659**	**558**	**1,550**	**21.6**	**18.3**
Dominican Rep.	3,217	49	98.9	275	419	558	1,252	16.6	22.1
Haiti	10,478	6	158.1	770	2,496	558	3,824	35.4	7.9
Iceland	**36**	**5**	**379.4**	**717**	**80**	**559**	**1,356**	**0.8**	**5.8**
India region	**1,658,265**	**6,728**	**107.1**	**259**	**1,408**	**558**	**2,225**	**53.8**	**21.3**
Bangladesh	161,682	234	109.6	306	2,238	558	3,103	72.2	18.0
India	1,444,634	6,396	106.5	253	1,369	558	2,180	53.4	21.8
Nepal	38,313	35	163.4	711	2,879	558	4,148	40.0	7.8
Sri Lanka	13,636	64	129.8	388	1,476	558	2,423	37.6	14.2
Israel	**1,544**	**90**	**154.8**	**284**	**175**	**558**	**1,017**	**6.9**	**22.0**

Jamaica	**698**	**13**	**178.6**	**416**	**258**	**559**	**1,232**	**7.1**	**15.3**
Japan	**27,181**	**1,215**	**126.2**	**269**	**215**	**558**	**1,042**	**8.4**	**21.8**
Mauritius	**418**	**10**	**198.2**	**489**	**377**	**559**	**1,424**	**8.2**	**12.2**
Mideast	**118,866**	**5,195**	**95.9**	**292**	**165**	**558**	**1,016**	**6.4**	**21.8**
Armenia	1,429	9	117.6	530	1,117	559	2,206	24.0	12.0
Azerbaijan	3,755	55	81.8	348	689	558	1,596	22.5	18.3
Bahrain	172	75	90.3	235	28	558	821	1.3	27.1
Iran	21,479	1,485	88.5	298	115	558	972	4.4	21.3
Iraq	12,495	418	39.0	148	217	558	923	16.7	42.9
Jordan	1,836	60	80.9	263	188	558	1,009	8.2	24.2
Kuwait	888	209	79.2	274	60	558	892	2.5	23.3
Lebanon	1,289	58	74.8	227	156	558	941	7.8	28.0
Oman	747	196	93.3	305	43	558	905	1.6	20.9
Qatar	203	225	103.8	349	16	558	924	0.5	18.2
Saudi Arabia	9,771	1,300	99.6	268	96	558	922	4.1	23.7
Syria	9,310	62	72.4	233	770	558	1,561	37.7	27.4
Turkiye	28,516	548	104.6	316	419	558	1,293	15.1	20.1
UAE	787	471	166.1	436	24	558	1,018	0.6	14.6
Yemen	26,189	23	53.5	207	3,854	559	4,620	212.0	30.7
New Zealand	**444**	**64**	**194.0**	**361**	**81**	**559**	**1,000**	**1.8**	**12.6**
Philippines	**126,965**	**348**	**112.0**	**241**	**1,946**	**558**	**2,746**	**82.4**	**23.6**
Russia region	**59,101**	**2,236**	**77.8**	**314**	**269**	**558**	**1,142**	**8.7**	**18.1**
Georgia	4,111	21	114.5	375	1,519	558	2,452	41.3	15.2
Russia	54,990	2,215	77.5	314	258	558	1,130	8.4	18.1
South America	**110,082**	**2,080**	**175.5**	**388**	**360**	**558**	**1,306**	**7.8**	**12.2**
Argentina	12,153	355	112.2	301	277	558	1,136	7.8	15.7
Bolivia	5,510	44	92.4	310	521	558	1,390	14.2	15.2
Brazil	49,639	886	239.3	493	398	558	1,450	6.8	9.6
Chile	4,119	174	156.3	287	222	558	1,067	6.5	16.4
Colombia	11,703	154	138.9	338	473	558	1,369	11.8	13.9
Curacao	9	11	105.2	367	7	558	932	0.2	12.8
Ecuador	2,873	72	107.6	286	222	558	1,066	6.5	16.5
Paraguay	2,511	15	296.7	632	822	558	2,012	11.0	7.5
Peru	13,130	100	145.8	350	768	558	1,677	18.5	13.5
Suriname	225	4	102.3	242	425	557	1,224	14.8	19.4
Trinidad/Tobago	271	58	113.5	195	44	558	798	1.9	24.2
Uruguay	675	12	341.0	630	448	558	1,636	6.0	7.5
Venezuela	7,264	196	111.3	297	254	558	1,110	7.2	15.9
Southeast Asia	**316,266**	**3,666**	**174.4**	**323**	**528**	**558**	**1,409**	**17.0**	**18.0**
Brunei	36	16	100.7	293	33	558	884	1.2	19.7
Cambodia	12,111	38	195.6	412	1,060	558	2,030	26.7	14.1
Indonesia	155,525	1,445	145.2	267	718	558	1,543	28.0	21.7
Lao PDR	6,920	16	194.0	438	2,018	558	3,015	47.8	13.2
Malaysia	9,353	575	153.5	267	166	558	992	6.5	21.7
Myanmar	50,469	112	153.5	365	1,769	558	2,692	50.4	15.9
Singapore	2,107	123	618.5	1,598	269	559	2,426	1.8	3.6
Thailand	35,606	635	201.3	369	456	558	1,383	12.8	15.7
Vietnam	44,139	705	152.9	205	297	558	1,060	15.0	28.3
South Korea	**8,980**	**944**	**184.2**	**298**	**111**	**558**	**967**	**3.9**	**19.7**
Taiwan	**6,649**	**639**	**148.6**	**240**	**134**	**558**	**933**	**5.9**	**24.6**
United States	**62,694**	**6,057**	**123.8**	**361**	**137**	**558**	**1,057**	**4.0**	**16.1**
All regions	**5,292,576**	**56,873**	**121.24**	**313**	**591**	**558**	**1,462**	**18.8**	**17.8**

[1]2050 country BAU mortalities due to air pollution are extrapolated from 2016 values from the World Health Organization [S51] using the method described in ref. [S14].

[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. The emissions from these 145 countries represent 99.7% of world anthropogenic CO_2e emissions.

[3]Calculated as the WWS private energy and total social cost from Table S36, 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 SS36, 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 S36, Columns (i)-(j), respectively, each divided by the BAU end-use demand from Table S36, Column (a) and by 8,760 hours per year.

Table S39. Parameters for Calculating Areas Required, Related to Table STAR Methods.
Footprint and spacing areas per MW of nameplate capacity and installed power densities for WWS electricity or heat generation technologies.

WWS technology	Footprint (m^2/MW)	Spacing (km^2/MW)	Installed power density (MW/km^2)
Onshore wind	3.22	0.0505	19.8
Offshore wind	3.22	0.139	7.2
Wave device	700	0.033	30.3
Geothermal plant	3,290	0	304
Hydropower plant	502,380	0	2.0
Tidal turbine	290	0.004	250
Residential roof PV	5,230	0	191.2
Commercial/govt. roof PV	5,230	0	191.2
Solar PV plant	12,220	0	81.8
Utility CSP plant	29,350	0	34.1
Solar thermal for heat	1,430	0	700

From ref. [S14]. Spacing areas for onshore and offshore wind are based on data from ref. [S52]. The installed power density is the inverse of the spacing except, if spacing is zero, it is the inverse of the footprint.

Table S40. Footprint and Spacing Areas, Related to Table STAR Methods.

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, for each grid region, in each case.

	All cases	Cases I-III			Case IV		
Region	(a) Region land area (km^2)	(b) Footprint area (% of region land area)	(c) Spacing area (% of region land area)	(d) Footprint + spacing area (% of region land area)	(e) Footprint area (% of region land area)	(f) Spacing area (% of region land area)	(g) Footprint + spacing area (% of region land area)
Africa	23,016,180	0.03	0.11	0.15	0.04	0.13	0.17
Australia	7,682,300	0.04	0.05	0.09	0.04	0.06	0.10
Canada	9,093,510	0.01	0.11	0.12	0.01	0.11	0.12
Central America	2,429,460	0.14	0.84	0.98	0.16	0.84	1.01
Central Asia	4,697,670	0.06	0.26	0.32	0.06	0.26	0.32
China region	11,063,254	0.51	0.86	1.37	0.51	0.97	1.48
Cuba	106,440	0.24	0.83	1.07	0.36	2.02	2.38
Europe	5,671,860	0.29	0.91	1.20	0.29	0.91	1.20
Haiti region	75,880	0.31	0.33	0.64	0.50	1.21	1.71
Iceland	100,250	0.00	0.08	0.08	0.00	0.08	0.08
India region	3,309,420	0.85	0.96	1.81	0.85	1.64	2.49
Israel	21,640	3.27	0.77	4.04	4.40	1.07	5.47
Jamaica	10,830	0.46	0.12	0.58	0.92	0.31	1.23
Japan	364,560	1.10	0.09	1.19	1.70	0.09	1.79
Mauritius	2,040	2.40	0.22	2.62	2.84	0.22	3.06
Middle East	6,327,218	0.34	0.54	0.88	0.34	0.65	0.99
New Zealand	263,310	0.09	0.81	0.90	0.09	0.81	0.90
Philippines	298,170	0.53	0.40	0.93	0.79	0.40	1.19
Russia region	16,446,360	0.01	0.16	0.17	0.01	0.16	0.17
South America	17,175,466	0.02	0.44	0.46	0.02	0.44	0.46
Southeast Asia	4,027,647	0.34	0.07	0.40	0.49	0.07	0.55
South Korea	97,350	5.10	0.03	5.13	7.76	0.03	7.79
Taiwan	36,193	4.16	0.42	4.58	6.75	0.42	7.17
United States	9,147,420	0.30	0.84	1.13	0.34	1.08	1.42
All regions	**121,464,428**	**0.16**	**0.39**	**0.55**	**0.18**	**0.45**	**0.63**

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. 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. Offshore wind, wave, and tidal are not included because they don't take up new land.

Table S39 gives the installed power densities applied in this table for each energy generator. Areas are given as a percentage of the region 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 S41. Parameters for Calculating Job Numbers, Related to Table STAR Methods.
Estimated mean number of long-term, full-time construction and operation jobs per MW nameplate capacity of different electric power sources and storage types in the United States. A full-time job is a job that requires 2,080 hours per year of work. The job numbers include direct, indirect, and induced jobs. These job numbers are scaled to different countries as described in the footnote of Table S42.

Electric power generator	Construction Jobs/MW or Jobs/km	Operation Jobs/MW or Jobs/km
Onshore wind electricity	0.24	0.37
Offshore wind electricity	0.31	0.63
Wave electricity	0.15	0.57
Geothermal electricity	0.71	0.46
Hydropower electricity	0.14	0.30
Tidal electricity	0.16	0.61
Residential rooftop PV	0.88	0.32
Commercial/government rooftop PV	0.65	0.16
Utility PV electricity	0.24	0.85
CSP electricity	0.31	0.86
Solar thermal for heat	0.71	0.85
Geothermal heat	0.14	0.46
Pumped hydro storage (PHS)	0.77	0.3
CSP storage (CSP-PCM)	0.62	0.3
Battery storage	0.092	0.2
Chilled-water storage (CW-STES)	0.15	0.3
Ice storage (ICE)	0.15	0.3
Hot water storage (HW-STES)	0.15	0.3
Underground heat storage (UTES)	0.15	0.3
Producing heat pumps for district heat	0.15	0.3
Producing and storing hydrogen	0.32	0.3
AC transmission (jobs/km)	0.073	0.062
AC distribution (jobs/km)	0.033	0.028
HVDC transmission (jobs/km)	0.094	0.080

From ref. [S2]. See Note S10 for more details.

Table S42. Changes in the Numbers of Long-Term, Full-Time Jobs, Related to Table STAR Methods. Estimated long-term, full-time jobs created and lost due to transitioning from BAU energy to WWS across all energy sectors in each region in each case, Cases I-IV. (a) Job losses, which are the same in each case; (b) net jobs produced (long-term, full-time jobs produced minus lost) in the base case (Case I). (c)-(e) Same as (b), but for Cases II-IV.

		Net jobs produced (jobs produced minus lost)			
Region	(a) Jobs lost in all cases	(b) Case I	(c) Case II	(d) Case III	(e) Case IV
Africa	4,545,041	-1,148,757	-1,108,449	-1,155,142	-796,187
Australia	364,616	258,583	251,122	257,706	279,519
Canada	702,683	-285,016	-285,016	-285,016	-285,016
Central America	559,964	690,877	528,108	523,385	540,167
Central Asia	885,570	162,287	159,056	161,663	149,876
China region	3,007,406	9,254,196	9,337,119	9,269,504	9,259,680
Cuba	20,726	87,945	79,826	70,429	115,288
Europe	2,282,091	3,334,701	3,185,314	3,293,624	3,187,276
Haiti region	39,348	40,725	39,954	40,963	81,735
Iceland	4,635	2,868	2,868	2,868	2,868
India region	2,611,937	4,266,721	3,782,606	3,798,913	4,122,752
Israel	33,687	151,660	119,679	102,172	138,890
Jamaica	5,617	20,931	19,685	20,375	29,778
Japan	260,005	713,596	669,135	671,596	842,520
Mauritius	5,543	9,699	9,120	8,037	9,442
Middle East	3,692,453	523,612	424,997	368,074	310,531
New Zealand	39,965	52,805	49,392	49,793	49,431
Philippines	137,336	356,331	307,018	331,323	432,683
Russia region	1,254,245	-292,172	-292,172	-292,172	-292,172
South America	1,965,734	422,930	422,930	422,930	422,930
Southeast Asia	1,987,573	2,067,359	2,069,744	2,042,590	2,971,169
South Korea	195,903	968,839	777,300	789,147	982,743
Taiwan	109,361	608,269	357,885	382,854	466,101
United States	2,478,720	3,020,516	2,700,247	2,700,801	3,277,306
All regions	**27,190,159**	**25,289,505**	**23,607,468**	**23,576,417**	**26,299,310**

Job 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.

Job creation accounts for new direct, indirect, and induced 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.

Jobs for electricity generation technologies are the number of long-term, full-time jobs per MW in each country multiplied by the 2050 final nameplate capacities (Table S11) minus the 2020 nameplate capacities (Table S10) for each device for construction jobs and the 2050 nameplate capacities alone for operation jobs. The jobs per MW for each device in each country is calculated with the methodology in ref. [S7] to scale U.S. jobs from Table S41 by year and country. For storage, the number of jobs per MW from Table S41is multiplied by the maximum discharge rate of the storage technology for each region (Table S15). The transmission/distribution jobs are calculated as in the spreadsheet [S3].

Supporting Figures

Figure S1. Hydropower Parameters, Related to STAR Methods.

Hydropower parameters as a function of the number of hours of storage for baseload power (H_b) for several regions when the number of hours to refill peaking storage is H_p=8,760 h. The curves are obtained from Equations S7-S12 and include the following parameters: C_p ("Average charge rate for peaking); N_p ("Maximum discharge rate for peaking"); C_b and N_b ("Charge and discharge rate for baseload"), S_p ("Storage capacity for peaking"), and S_b ("Storage capacity for baseload"). Table S15 provides the total charge rate for peaking plus baseload (C_t), the total nameplate capacity for peaking plus baseload (N_t), and the maximum storage capacity for peaking plus baseload (S_t) for each region. For example, for Africa, C_t=14.46 GW, N_t=31.52 GW, and S_t=125.4 TWh, respectively.

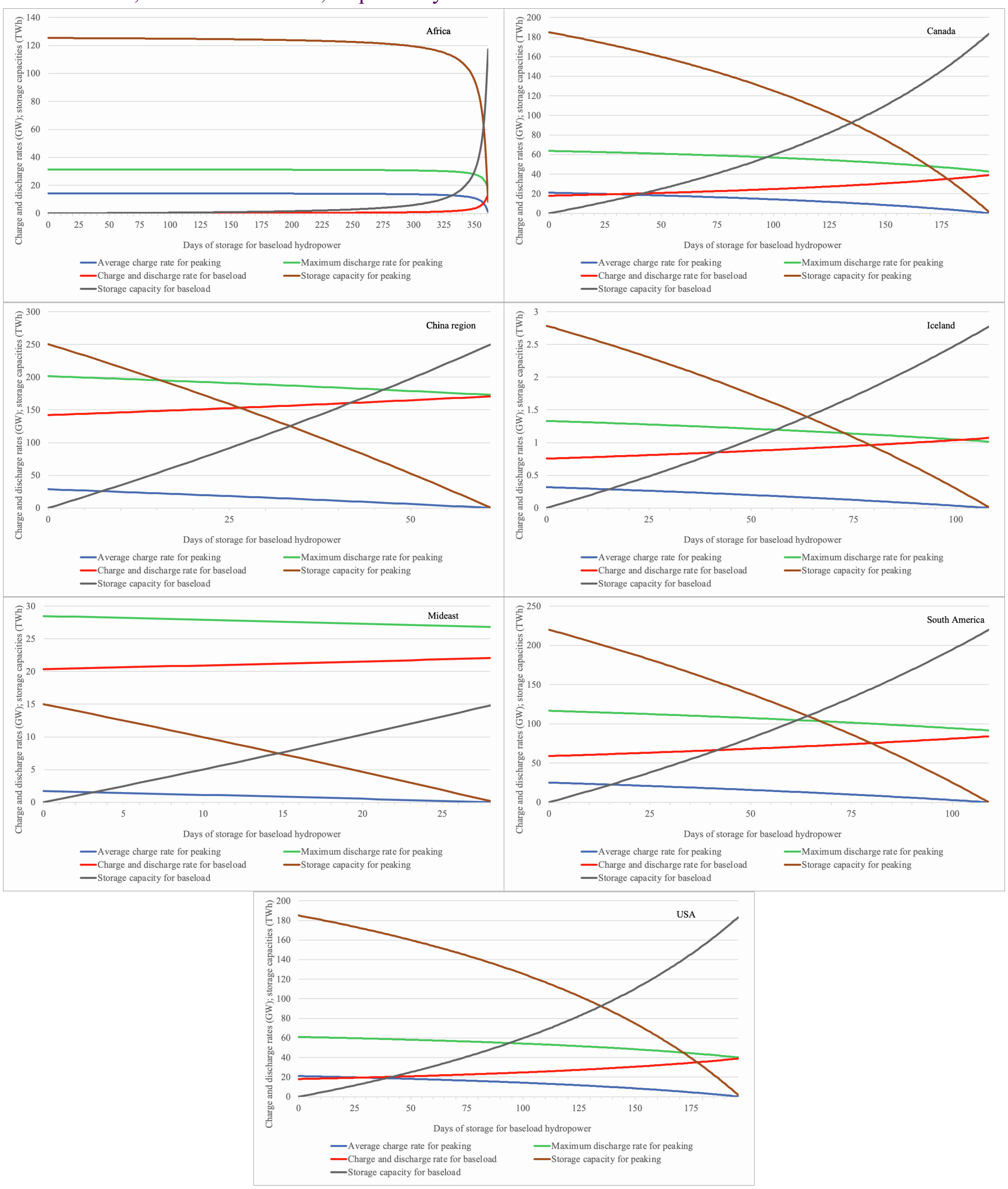


Figure S2. Battery and Hydrogen Storage Parameters, Related to Figure 1.

Peak power discharge rate, peak storage capacity, and hours of storage at the peak discharge rate for battery storage (BS) and green hydrogen storage (GHS) in each Case I-IV, for each of 10 world regions in which battery storage for grid electricity is needed in this study. The regions with no figure because battery storage is not needed, thus replacing batteries with GHS is not needed, are Canada, Iceland, the Russia region, and South America. The number of hours of storage equals the storage capacity divided by the peak power discharge rate. In Case I, no GHS is used for grid electricity, and in Case IV, no BS is used. In Case II, the hydrogen storage is communal for grid- and non-grid-hydrogen. The storage capacity in that case is that of the communal storage, and the peak power discharge rate is the nameplate capacity of the fuel cell discharging for grid electricity. Thus, the number of hours of storage is the time it takes to fully discharge the communal storage at the peak discharge rate as if it is being discharged solely for grid electricity. In Case III, the hydrogen storage capacity is solely that of hydrogen for grid electricity, and the fuel cells used for grid electricity are assumed to consume only that hydrogen. Case IV is the same as Case II, except with no batteries. Tabulated values are provided in Tables S18-S21.

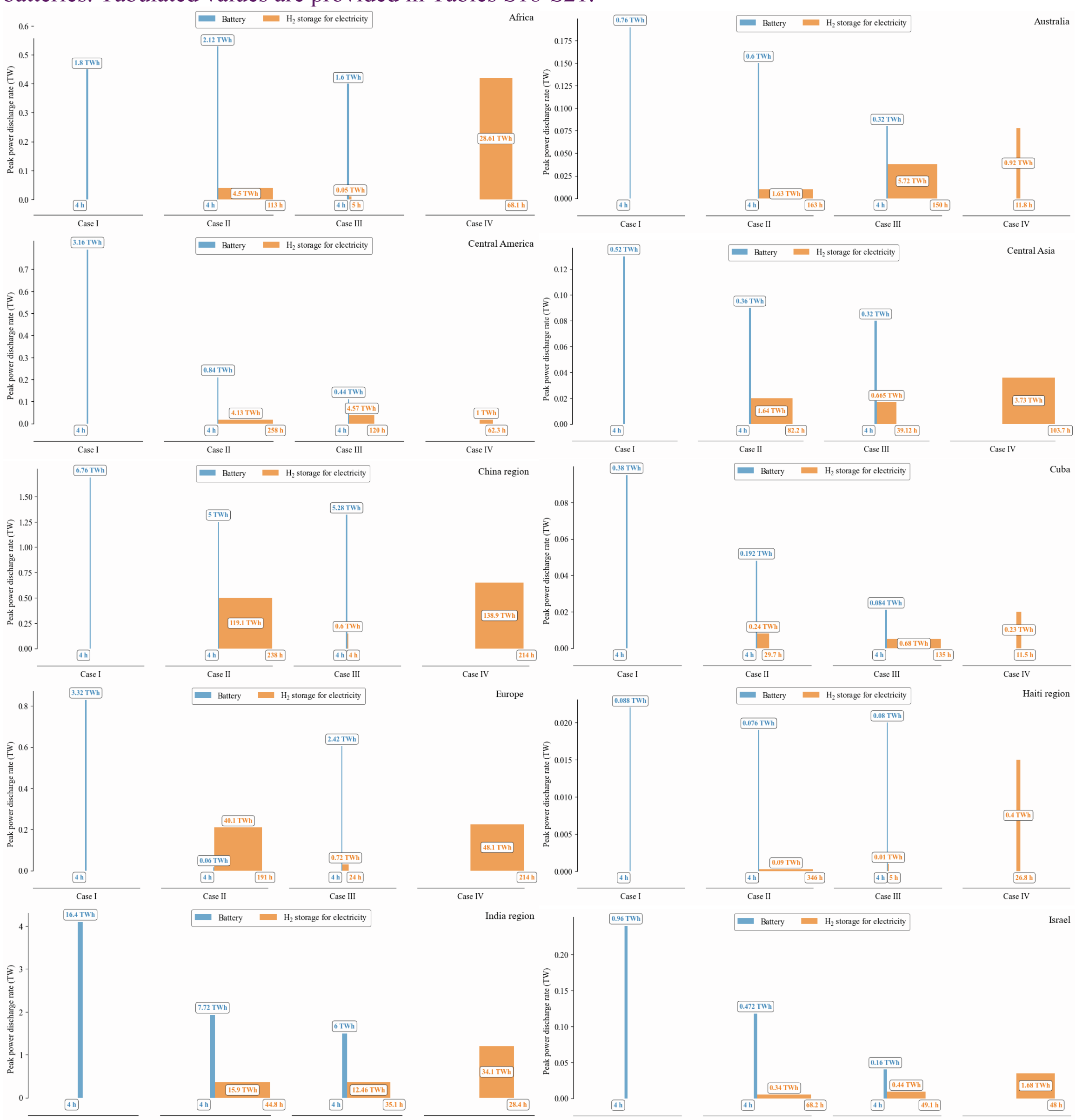


Figure S3. Battery and Hydrogen Storage Parameters, Related to Figure 1.

Same as Figure S2, but for 10 more regions in which battery storage for grid electricity is needed and for all 24 regions combined. Tabulated values are provided in Tables S18-S21.

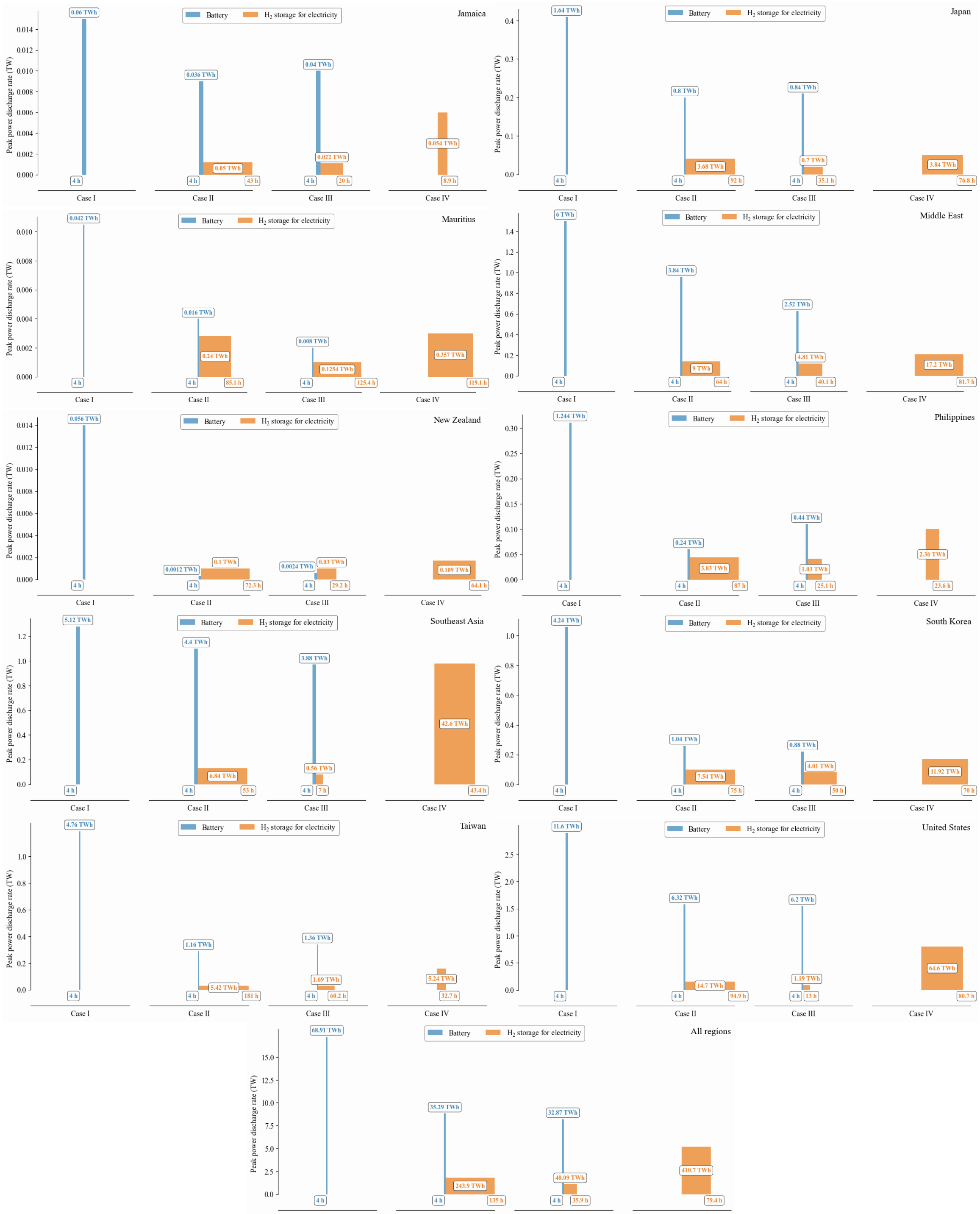


Figure S4. Capital Cost by Region, Related to Table 1.

2050 mean total capital cost (2020 USD) of a 100% WWS system in Cases I-IV. Tables 1 and S33-S35 contain the numerical data.

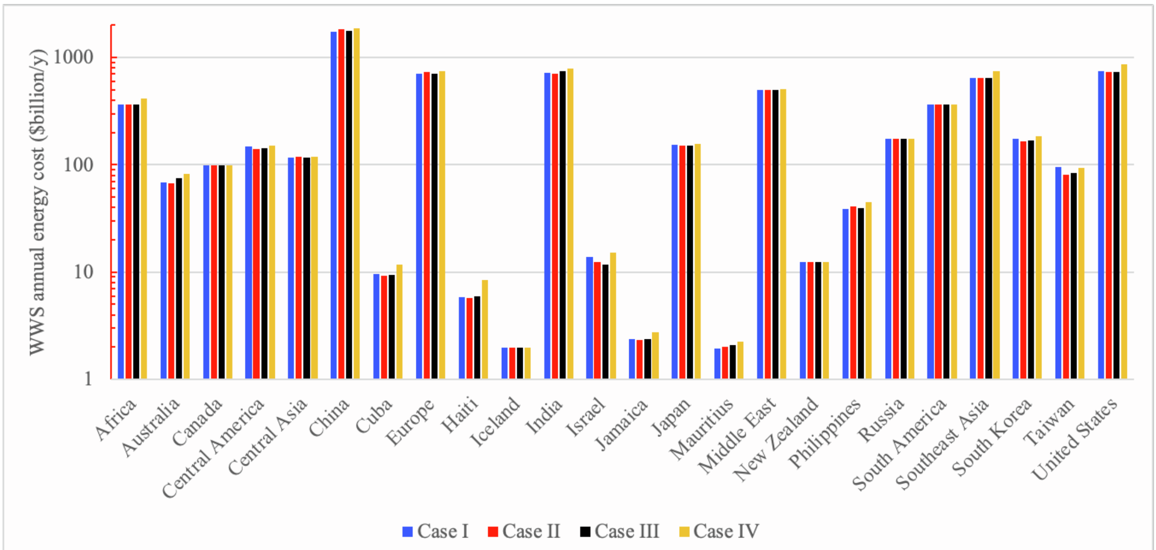
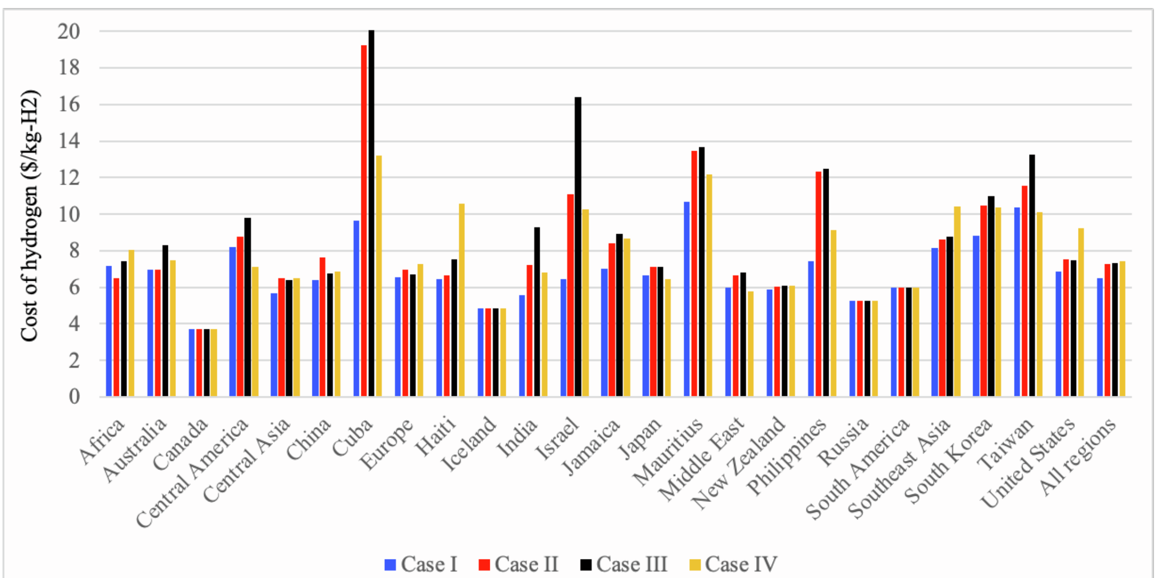


Figure S5. Cost of Hydrogen, Related to Table 1.

2050 mean total cost per kilogram of hydrogen in Cases I-IV (2020 USD). Data are from Tables S28-S32, which contain a breakdown of non-grid and grid hydrogen component costs by region for each Case I-IV and mean, high, and low overall costs of hydrogen for each case.). For Case III, the separate costs of non-grid and grid hydrogen are weighted by the annual production of each non-grid and grid hydrogen from Tables S28-S32.



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