Electronic Supplementary Material (ESI) for Energy & Environmental Science.

Electronic Supplementary Information

S-1- Sensitivity to model structural assumptions

Here, we expand the discussion provided in the Conclusion section on the impact of the major assumptions and simplifications on our key results. Table S1 lists the key assumptions and our judgment on whether they favor or disfavor BES.

Table S1: Qualitative comparison of the major assumptions and simplifications of the model to the real world and their likely impact on the key results. A plus sign indicates the corresponding assumption/ simplification favors BES in our model compared to a given counterfactual. A negative sign shows the assumption disfavors BES.

Assumption	**Counterfactual**	**Implications**	**Impact on BES**
Green-field analysis	A model with temporal evolution and vintaging of generation capacity in which factors costs and emissions constraints gradually approached the values used in our model (*i.e.* brown-field analysis).	The brown-field model would keep much of the existing gas assets, making BES less competitive as the capital cost of gas turbines would be 'free'.	+
Transmission costs and constraints are ignored	A model with transmission constraints which also considers costs of adding new transmission	Transmission costs driven by resource remoteness would increase the net cost of wind. This would make wind a bit less competitive with DZC and gas, slightly decreasing the need for BES. Moreover, siting of some BES systems (*e.g.* PHS) is geographically constrained. Therefore, considering transmission would hurt economics of some BES.	+
		Transmission costs can incent siting BES near generation (especially wind and solar) to allow economic optimization of the transmission capacity. Moreover, strategically siting of BES across the grid can relieve constraints and defer transmission upgrades.	-

Wind data are from ERCOT with a capacity factor of 35%	A model considering a wide range of geographical areas with different wind and load profiles	ERCOT is endowed with relatively strong wind resources. Lower capacity factors would make wind more capital-intensive and give gas and DZC an advantage over wind and BES. System-wide capacity factors significantly beyond 35% seem unlikely to us.	+ (for capacity factors below 35%)
		Correlation between wind and load may vary in different geographical regions. Repeating the simulation for other systems can enhance robustness of results.	-
Solar energy is not modeled	A model allowing both wind and solar capacity	Solar farms have lower capacity factors and are currently more expensive (~>1.5 times) compared to wind farms. Therefore, we do not expect considering solar will alter our conclusions about the need for BES, unless cost of solar steeply drops below of wind in future.	nil
		Wind availability is sometimes higher overnight and in winter, in contrast to load. Changes in solar irradiance may follow changes in load better. This may improve economics of solar-based electricity, which could move the need for storage in both directions. Modeling a broader set of generation portfolio, including solar will strengthen the analysis.	-
15-minute time resolution	A model considering finer resolutions and reliability/ security requirements of the grid (*e.g.* black start)	A high-temporal resolution model would build storage for the short duration load balancing, but this is independent from bulk storage of electricity, the focus of this paper.	nil
1-year simulation period	Taking into account inter-annual variations in wind	Renewable energies, especially wind, can experience large inter-annual variations, which increase their effective cost and reduce their optimal capacity.	+

Static modeling	A model considering future reductions in cost of all technologies (gas, wind, and DZC), not just BES	Using current cost estimates for gas turbine, DZC, and wind can favor BES providing their costs can be reduced faster than BES and vice versa.	nil
Gas price of $5/GJ	A model considering future gas prices across various region and electricity markets	According to section S-6, we do not expect major impacts on the key conclusions unless gas prices are above $20/GJ.	- (if price is beyond ~$20/GJ)
Forecast errors in load and wind are ignored	A model considering forecast errors (ax-ante rather than ex-post) and their improvement over time	Utilization factor of wind and BES would be lower in the real world. Our model can build the smallest amount of wind and BES to economically meet the electric load. Therefore, considering forecast errors would make wind and BES more capital intensive and less economical.	+

S-2- Correlation between wind and load profiles

Correlations between wind availability and electric load obviously impact storage requirements. ERCOT is a large electricity grid (peak load of 66.5 GW and wind capacity of 10.0 GW in 2012), so the chosen profiles represent an important real world case. The load factor defined as ratio of the average to peak load is 56% for our load profile. There is a slight anti-correlation (coefficient of -0.15) between our load and wind profiles. Cumulative duration curves for load and wind are shown in Figure S1. Note that there are periods with insignificant wind availability while the load does not ever fall below 34% of its peak. Even if wind capacity is 1.6 times of the peak load– the point at which annual average wind production matches the annual average load– wind will still be incapable of supplying all of the load 53% of the time (marked by point "B" on the graph). This value is still non-negligible (17%) even when wind capacity is 5 times larger than peak load (point "C" on "n=5" line).

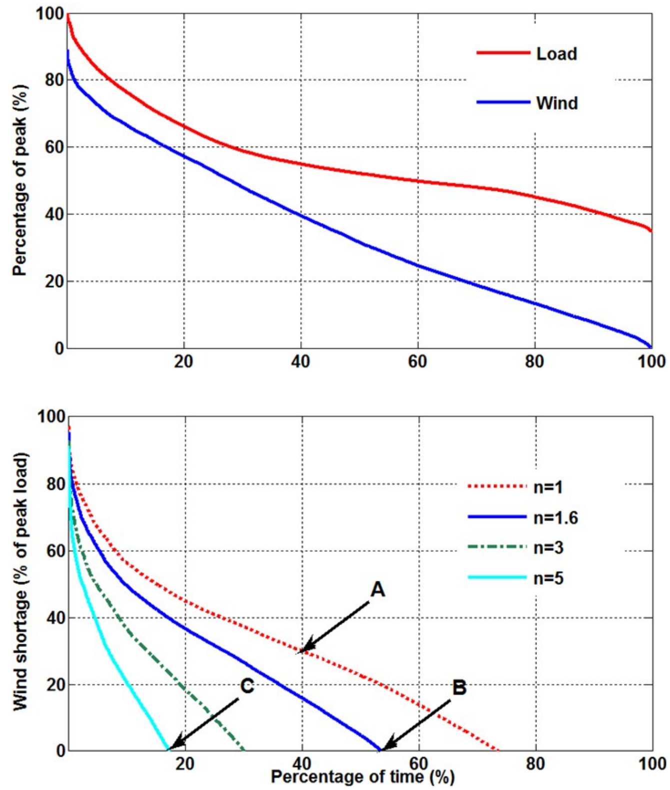


Figure S1: Temporal distribution of wind and load profiles used for the simulation. The top figure illustrates percentage of time (on horizontal axis) during which wind availability or electric load is higher than a certain value shown on the vertical axis (*a.k.a.* duration curve). Wind and load profiles are normalized to peak load and installed wind capacity, respectively. The lower plot shows percentage of time during which wind shortfall in supplying the load is higher than a certain value shown on the vertical axis. Parameter "n" is the ratio of wind capacity to peak load. Point "A" for example, shows that in 40% of the year shortage in wind supply is at least 30% of the annual peak load, when the installed wind capacity is equal to the annual peak load (n=1).

S-3- Mathematical formulation of optimization

We simultaneously optimize installed capacity and dispatch during operation of a generation fleet to meet the load at the minimum cost. We use a set of scenarios defined by a series of imposed constraints on the annual average GHG intensity of electricity ranging from 300 to 0 $kgCO_2e/MWh$. The power- and energy-specific CapEx of BES are varied to sample the two-dimensional (X_E and X_P) space within each emissions intensity scenario. The system-average levelized cost of electricity (LCOE, \$/MWh) is minimized at each emissions intensity and at the sampled values of X_E and X_P. The LCOE includes fixed and variable operating and maintenance costs (FOM and VOM), fuel costs, and amortized CapEx. The objective function is given below, given the definitions in Table S2.

$$\sum_{y}\left[\left\{Capt_y \times \left(BC \times CapEx_y + FOM_y\right)\right\} + \left\{\sum_{z}\left(EL_{y,z} + ST_{y,z}\right) \times \left(HR_y \times \pi_{NG} + VOM_y\right)\right\}\right]$$

Where $y \in Y = \{SCGT, CCGT, Wind, BES, DZC\}$ and $z \in Z = \{1,2,3, \ldots, 365 \times 24 \times 4\}$

Table S2: List of parameters and variables of the objective function.

$CapEx$	Specific capital cost ($/MW or MWh)	$Capt$	Installed capacity (MW or MWh)
BC	Blended cost of capital (%)	EL	Electricity delivered to load (MWh)
FOM	Fixed operation and maintenance cost ($/MW or MWh/year)	VOM	Variable operation and maintenance cost ($/MWh)
Y, y	Set Y includes the electricity supply technologies, *i.e.* gas turbines, wind, BES, and DZC (index y)	Z, z	Set J includes the planning periods over the entire year at a 15-minute resolution (index j)
π_{NG}	Price of gas ($/GJ)	ST	Electricity stored in BES (MWh)
HR	Heat rate (GJ/MWh)		

This objective function calculates the total annual cost of electricity supply and has two parts (shown in curly brackets). The first section takes into account the amortized capital cost and the fixed operations and maintenance cost of the generation and storage fleet. The second part of the objective function considers the fuel cost and the variable operation and maintenance cost associated with electricity generation (both directly provided to the load and stored in BES) and by the generation fleet. Note that we simultaneously optimize the capacity and dispatch of the generation fleet. We develop a simplified utility planning model, which minimizes the system-wide cost of electricity supply in a green-field setup.

The decision variables include installed capacity (size) of the generation fleet and their dispatch in each 15-minute period over the simulation period (one year). The key constraints include:

- The electricity load must be satisfied in each 15-minute time interval.
- The annual average GHG emissions (kgCO2e/MWh) should be less than a preset value (*e.g.* 0 in the carbon free scenario), except in the BAU scenario.
- Output of each system component cannot exceed its capacity.
- Conservation of energy must hold for BES; the change in the stock of energy in each 15-minute period should be equal to the difference between energy injected and withdrawn, after taking into account the storage efficiency.

S-4- GHG emissions intensity of gas-based electricity

We use a GHG intensity of 66 $kgCO_2e$/GJ (low heating value, LHV) [6] for natural gas to account for upstream emissions in addition to combustion emissions, which leads to a GHG intensity of 647 and 442 $kgCO_2e$/ MWh for the SCGT and CCGT plants modeled. Although estimating life-cycle GHG emissions of natural gas-based electricity is uncertain (partly due to fugitive methane emissions), our values fit well within the current estimates. For instance, in a 2014 study, O'Donoughue et al. [32] applied a meta-analytical process on 250 published references to harmonize estimates of the life-cycle GHG emissions of electricity fueled by conventionally produced gas. They reported an interquartile range (IQR) of 570-750 with a median of 670 $kgCO_2e$/MWh for SCGT. The IQR and median values reported for CCGT are 420-480 and 450 $kgCO_2e$/MWh, respectively.

S-5- Sensitivity to capital cost of DZC

Cost figures for DZC are extremely uncertain due to their limited recent deployment. As a case in point, estimates for the Vogtle AP1000 nuclear plant currently under construction in GA, USA is around 6400 $/kW [33]. The figures for the Korea-UAE nuclear contracts announced in 2009 ($3700/kW [34]) is however, almost half of for the Vogtle project. In a recent study, Abdulla et al. [35] used expert elicitations to estimate capital cost of light water reactors, both based on current technology and small modular reactors (SMR). The median of the estimates for a 1 GW reactor ranged from $2600 to $6600/kW while it varied between $4000 and $16300/kW for a 45 MW light water SMR. Cost figures for CSP also lay in a wide range. Estimates for the Crescent concentrated solar power plant (110 MW, 10 hours of thermal storage, under construction in NV, USA) are about $9000/kW [36, 37] . The price tag of the Solana plant (250 MW, 6 hours of thermal storage, commissioned in 2013 in AZ, USA) is roughly $8000/kW [37]. We use a value of $9000/kW for capital cost of DZC in the base case model.

Figure S2 explores the robustness of our key results and conclusions to the capital cost of DZC. Three scenarios are illustrated in this figure:

a) no BES is allowed (to quantify the economic value of BES at current capital costs in decarbonizing the electricity supply),
b) BES is available at the current costs, and
c) a scenario with 50% reduction in both the energy-specific capital cost (X_E) and power-specific capital cost (X_P) of BES compared to the current levels considered in case b.

We chose one generic BES system from the mechanical (with current costs of X_E=30 $/kWh and X_P=1500 $/kW) and electrochemical (X_E=375 $/kWh and X_P=550 $/kW) BES category to perform this sensitivity analysis. All other simulation inputs have the same values as the base case simulation (listed in Table 2).

The simulated mechanical BES system is much more successful in reducing the LCOE and its power capacity is consistently and considerably (~2-3 times) higher than of the electrochemical system. The optimal BES capacity is almost zero when the cost of DZC is ≤$6000/kW (for the mechanical category) and $9000/kW (for the electrochemical system) with current cost estimates for BES. This is because wind and BES lose their economic competitiveness as DZC gets less capital intensive. Even cutting both power and energy capital costs of the battery makes marginal changes in the LCOE (≤ $1/MWh) unless capital cost of DZC remains above $9000/kW. As we discussed in section 2-3, DZC represents the least capital intensive, dispatchable technology—CSP, nuclear, CCS, biomass or geothermal (possibly even with high voltage direct current, HVDC, transmission lines)—that can be utilized in a given location. We believe that the value of 9000 $/kW used in this paper is mostly likely an overestimate of this best-case DZC cost.

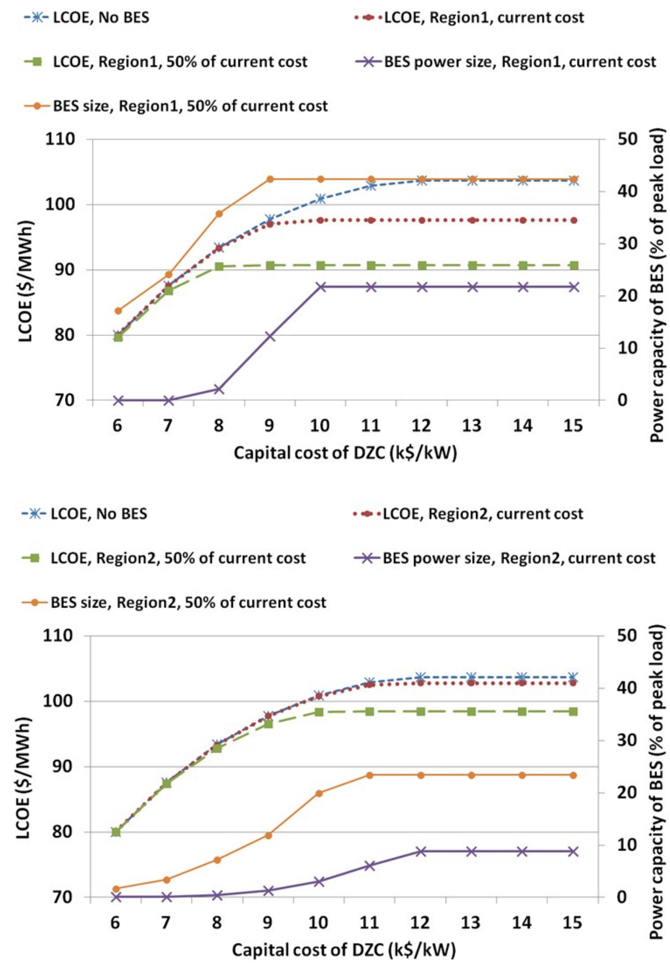


Figure S2: Sensitivity of LCOE and power capacity of BES to capital cost of DZC. Each sub-plot presents three cases: a) no BES is allowed, b) BES at the current capital costs and, c) BES with 50% reduction in both X_E and X_P values considered in case b. The sub-figure on top shows the results for a generic BES system in region 1 with X_E=30 $/kWh and X_P=1500 $/kW as its current costs. The sub-figure at the bottom represents region 2 with X_E=375 $/kWh and X_P=550 $/kW as the current costs. Region 1 and 2 represent mechanical and electrochemical bulk storage systems (see Figure 1). Price of gas is $5/GJ.

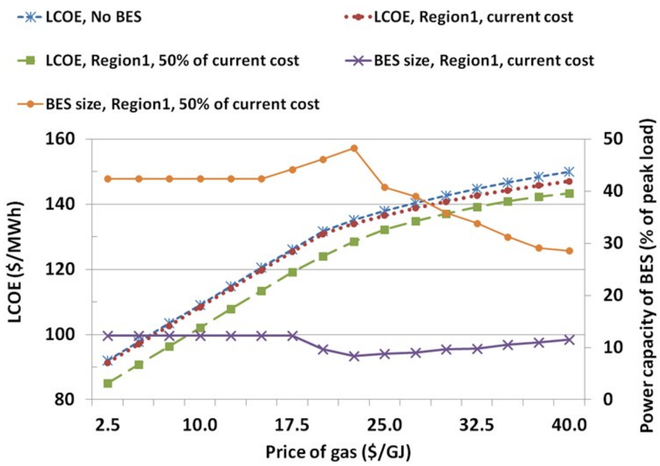
S-6- Sensitivity to price of gas

We used $5/GJ as the price of natural gas in the base case results presented. This value is comparable to the average price of $4.8/GJ paid by power plants across the United States between 2009 and 2013 [38]. Due to uncertainties in future gas prices especially under emissions restrictions and in the wake of the unconventional gas revolution, here we evaluate robustness of our key conclusions to this parameter. Similar to Figure S2, Figure S3 illustrates the LCOE and power capacity of a generic mechanical and a battery BES system, but with respect to price of gas instead of DZC CapEx. The GHG emissions intensity is capped at 150 kgCO_2e/MWh and all parameters except price of gas are the same as Table 2.

The availability of BES marginally impacts the overall cost of electricity with the current BES capital costs figures, although the mechanical BES system starts to matter at high gas prices ($20/GJ). Reducing the energy-specific and power-specific capital costs (X_E and X_P) of the mechanical BES by

50% lowers the LCOE much more (3.5-7.0 $/MWh compared to LCOE at current X_E and X_P cost figures), particularly with gas prices below $20/GJ, compared to the generic electrochemical system. There is a maximum of $2.5/MWh difference between the electricity supply cost of the generation fleet utilizing the electrochemical system with the current capital costs and with 50% cost reduction (occurring at an unrealistically high gas price of $40/GJ).

The optimal power capacity of BES is far more sensitive because of the reduced optimal capacity of gas turbines at high gas prices and the competition between wind, BES, and DZC to compensate for that. Our conclusion that the optimal capacity of the mechanical BES systems is higher (~2-3 times) compared to of the battery systems, especially with 50% cost reductions, is also robust to changes in gas prices.



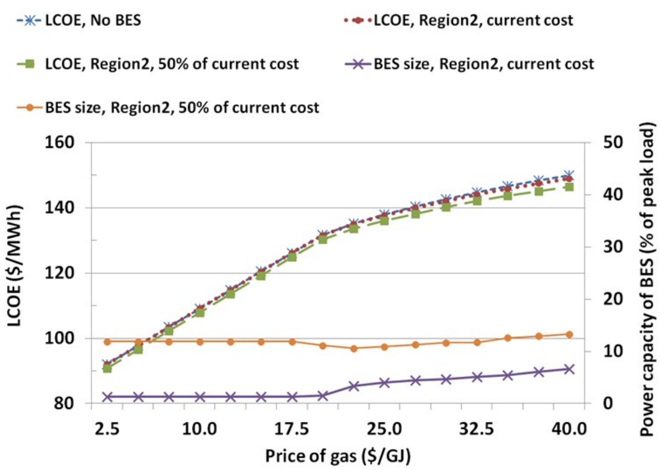


Figure S3: Sensitivity of the LCOE and optimal power size of BES to the price of gas. Each sub-plot presets three cases: a) no BES is allowed b) BES at the current costs, and c) 50% reduction in both X_E and X_P compared to case b. The top sub-figure presents a generic mechanical BES system (from region 1 in Figure 1) with X_E=30 $/kWh and X_P=1500 $/kW as its current costs. The sub-figure at the bottom represents a generic electrochemical technology (from region 2 of Figure 1) with X_E=350 $/kWh and X_P=550 $/kW as the current costs.

S-7- Optimal size and market share of storage

Figure S4 illustrates the power and energy size of BES, percentage of annual load supplied by the energy stored in BES (i.e. market share of BES), and share of DZC of the total electricity production, as discussed in section 3-3.

The power capacity of BES remains below 30% and 10% of the peak load for the mechanical and electrochemical battery BES systems, respectively. The optimal energy capacity of BES is also small; the cheapest storage system modeled (X_E=5 $/kWh and X_P=100 $/kW) barely has enough capacity to meet the average load for 40 hours. Note that the small BES share of annual electricity supply in comparison to its relatively larger capacity size (especially the power size for mechanical systems) indicates that BES is dispatched infrequently and mainly in the periods of high load (*i.e.* peak shaving application).

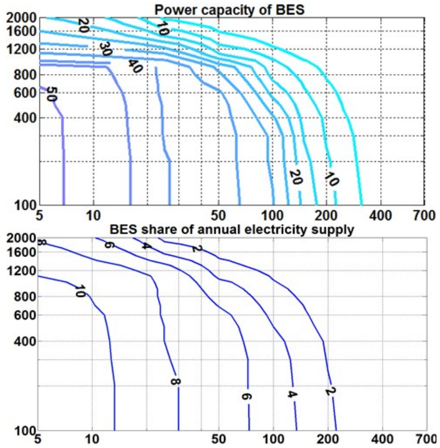


Figure S4: Market share of storage at an emissions cap of 150 kgCO2e/MWh. Subfigures from top left illustrate normalized power size and energy size of BES, percentage of annual load supplied by the energy stored in BES, and DZC share of the total annual electricity production. Horizontal and vertical axes show X_E ($/kWh) and X_P ($/kW).

As discussed in section 3-2, we quantify the importance of BES versus gas turbine for wind integration by comparing their optimal capacity when DZC is kept out of the generation fleet. Table S3 presents the key system parameters when DZC is eliminated from the generation fleet and the same emissions constraint of 150 kgCO_2e/MWh is enforced. A sample BES system from each category (*i.e.* mechanical and electrochemical) was modeled. The energy- and power-specific costs of the mechanical BES system were X_E=30 $/kWh and X_P=1500 $/kW while these values were X_E=375 $/kWh and X_P=550 $/kW for the sample electrochemical BES system. We also evaluated the sensitivity of the results to a drastic 50% reduction in both X_E and X_P of these two BES systems.

The required amount of storage remained relatively small (≤22% of peak load, except when the energy and power costs of the mechanical BES system were halved). In contrast, capacity of the gas turbine fleet (aggregate of SCGT and CCGT) remained above 75% of the peak load with the current storage costs of both BES systems and still above ~50% when the costs of the mechanical BES were halved. Moreover, less than 10% of the annual electricity load was supplied by BES in the best case (50% reduced energy and power costs of the mechanical system). Also note the low sensitivity of the overall cost of electricity (LOCE) to reductions in the capital cost of BES. Halving both the power and energy cost of the mechanical and electrochemical systems reduced LOCE by 7% and 4%, respectively.

Using the example of the mechanical BES system shown in Table S3 (with energy and power costs of X_E=$30/kWh and X_P=$1500/kW), we see that capacity of BES and gas are ~20% and 60% (respectively) of the capacity of wind. So one could say that BES is three times less important than gas in providing peaking power under this tight emissions constraint and with current capital cost estimates. Under these conditions, about a third of annual load comes from gas, 6% from BES and the rest from wind.

Table S3: Key characteristics of the generation fleet when DZC is eliminated from the model at an emissions cap of 150 kgCO_2e/MWh and gas price of $5/GJ. The "Reduced CapEx" columns refer to 50% reduction in both the energy (X_E) and power (X_P) capital cost of storage, compared to the current cost estimates. Region 1 and 2 represent a generic mechanical and electrochemical BES system (see Figure 1). GT refers to simple (SCGT) and combined (CCGT) cycle gas turbines. All other input parameters are the same as Table 2.

	Current CapEx		**Reduced CapEx**	
Storage system	**Region 1**	**Region 2**	**Region 1**	**Region 2**
Energy-specific CapEx ($/kWh)	$30	$375	$15	$188
Power-specific CapEx ($/kW)	$1500	$550	$750	$275
LCOE ($/MWh)	$97.6	$103.0	$90.7	$98.9
BES power capacity (% of peak load)	22	8	42	22
BES energy capacity (hrs of average load)	9	1	18	3
BES market share (% of annual load)	6	1	9	4
GT capacity (% of peak load)	75	88	54	74
GT generation share (% of annual electricity generation)	34	34	34	34
Wind capacity (% of peak load)	120	138	115	127
Ratio of BES power to wind capacity	0.18	0.06	0.37	0.18
Ratio of GT to wind capacity	0.62	0.64	0.47	0.58
Ratio of GT to BES capacity	3.4	10.7	1.3	3.2

The relative importance of BES and GT depends on stringency of the emissions cap too. Here we presented the results at an emissions cap of 150 kgCO_2e/MWh – ~70% reduction compared to the current emissions levels in the United States. With zero or near-zero emissions and no use of DZC, larger storage capacities will be needed to manage wind's intermittency as GT gets too polluting for such extremely low-carbon grids.

Price of gas is another important factor in determining the relative importance of bulk storage. To explore its effect, we repeat the simulation with a much higher gas price of $20/GJ (Table S4) instead of $5/GJ (Table S3). The optimal ratios of BES and GT to wind capacity do not vary in a substantial manner with $20/GJ gas, except when the cost of the mechanical system is cut by 50%. This indicates that the low capital cost of the gas turbine fleet (Table 2) out-competes its higher operation and fuel costs, hence the GT still supplies one third of the load with $20/GJ gas.

Table S4: Key characteristics of the generation fleet when DZC is eliminated and at an emissions cap of 150 $kgCO_2e/MWh$ and gas price of $20/GJ. The "Reduced CapEx" columns refer to 50% reduction in both the energy (X_E) and power (X_P) capital cost of storage. Region 1 and 2 represent a generic mechanical and electrochemical BES system (see Figure 1). All other parameters are the same as of Table 2.

	Current CapEx		Reduced CapEx	
Storage system	**Region 1**	**Region 2**	**Region 1**	**Region 2**
Energy-specific CapEx ($/kWh)	$30	$375	$15	$188
Power-specific CapEx ($/kW)	$1500	$550	$750	$275
LCOE ($/MWh)	$131.7	137.1	124.1	133.0
BES power capacity (% of peak load)	22	8	46	22
BES energy capacity (hrs of average load)	9	1	23	3
BES market share (% of annual load)	6	1	11	4
GT capacity (% of peak load)	75	88	50	74
GT generation share (% of annual electricity generation)	34	34	27	34
Wind capacity (% of peak load)	120	138	130	127
Ratio of BES power to wind capacity	0.18	0.06	0.36	0.18
Ratio of GT to wind capacity	0.62	0.64	0.39	0.58
Ratio of GT to BES capacity	3.4	10.7	1.1	3.2

S-8- Effect of reducing energy and power capital costs on LCOE

Figure S5 illustrates the impact of a 50% reduction in both energy- and power-specific costs of BES at an emissions cap of 150 $kgCO_2e/MWh$, similar to Figure 4 but for LCOE instead of market share of storage. As shown, none of the existing technologies alter LCOE in a major way. Consistent with Figure 4, mechanical BES systems (A-CAES and PHS) are more beneficial in lowering LCOE, although their impact is small.

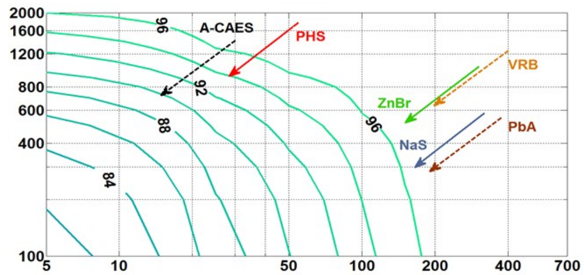


Figure S5: Overall cost of electricity (\$/MWh) at an emissions cap of 150 kgCO2e/MWh when different BES technologies are deployed. Horizontal and vertical axes indicate X_E (\$/kWh) and X_P (\$/kW). Arrows start from the current cost estimates (average of the range shown for each technology in Figure 1) and end at points with 50% reduction in both X_E and X_P.

S-9- Performance of diabatic CAES

We analyzed diabatic CAES separately since unlike all other BES technologies it has non-negligible emissions. The heat rate and work ratio of CAES were set at 4.2 GJ/MWh and 0.75 in our model, respectively. Therefore, the simulated CAES facility emitted 277 kgCO_2 per MWh of electricity generated (inside-the-fence lines emissions). We varied X_E and X_P of diabatic underground CAES in the range of 5-25 \$/kWh and 850-1200 \$/kW, based on the estimates from Table 1. Aboveground CAES was not modeled due to its obvious weaker performance (caused by much higher energy-specific capital cost of >200 \$/kWh, refer to Table 1 for details).

We present results from the 150 kgCO_2e/MWh cap scenario in Table S5. Availability of diabatic CAES made negligible differences in LCOE. The cheapest CAES system modeled (X_E=5 \$/kWh and X_P=850 \$/kW) could only store enough electricity to meet the average load for ~1 hour and its power capacity is 7% of the peak load. A higher gas price of \$10/GJ instead of \$5/GJ did not improve the competitiveness of CAES.

For the sake of comparison, we also modeled A-CAES system (heat rate of zero and efficiency of 63%) with the same emissions cap and gas prices. We used the range of 1100-1700 \$/kW and 10-50 \$/kWh for the power and energy capital cost of A-CAES (refer to Table 1). As seen in Table S5, the role of A-CAES turned out more significant compared to diabatic CAES despite its much higher capital cost. LCOE of the system equipped with A-CAES instead of diabatic CAES was lower (~4% in the base case). Moreover, both the power and energy capacity of A-CAES were much higher compared to of diabatic CAES. The GHG emissions of diabatic CAES severely limit its competitiveness as a BES system under emissions constraints. Note that the significance of diabatic CAES (measured by its impact on LCOE and by its optimal installed capacity) turned out to be even smaller under no emissions constraints (BAU scenario). These results lead to the conclusion that diabatic CAES is too capital intensive for today's grids (no major GHG emissions restrictions) and too polluting for the future low-carbon grids.

Table S5: Key characteristics of underground diabatic CAES and A-CAES at a grid emissions cap of 150 kgCO_2e/MWh. All other inputs are the same as Table 2.

Parameter	**Diabatic CAES**		**A-CAES**	
Power CapEx ($/kW)	850-1200		1100-1700	
Energy CapEx ($/kWh)	5-25		10-50	
Efficiency (%)	NA		63	
Work ratio (MWh in/ MWh out)	0.75		1.60	
Heat rate (GJ/MWh)	4.2		0	
Price of gas ($/GJ)	5	10	5	10
LCOE ($/MWh)	97.7-97.8	109.1	93.8-97.8	105.2-109.1
Power capacity (% of peak load)	6-0	6-0	33-1	33-1
Energy capacity (hours of average load)	1-0	1-0	19-0.2	19-0.2

S-10- LCOE of scenarios discussed in the Conclusion section

Table S6 provides the LCOE of various scenarios discussed in the Conclusion section for the sensitivity of the key conclusions to price of gas, capital cost of wind, DZC, and BES, and storage efficiency of A-CAES.

Table S6: LCOE corresponding to sensitivity analysis discussed in the Conclusion section. All cases assume an emissions cap of 150 $kgCO_2e/MWh$.

Scenario	LCOE ($/MWh)	% change W.R.T base case
Base case (Table 2 with X_E=25 $/kWh, X_P=1500 $/kW, and GHG cap= 150 $kgCO_2e/MWh$)	96.8	0%
Base case with X_E=5 $/kWh and X_P=100 $/kW	81.2	-16%
Base case with $1000/kW wind	72.0	-26%
Base case with $4500/kW DZC	68.6	-29%
Base case with $10/GJ gas	108.1	+12%
Base case with X_E=5 $/kWh, X_P=100 $/kW, and $10/GJ gas	92.6	-4%
Base case with $4500/kW DZC and $10/GJ gas	83.4	-14%
Base case with $1000/kW wind and $10/GJ gas	77.7	-20%
Base case with X_E=30 $/kWh and X_P=1400 $/kW (A-CAES cost values)	96.7	~0%
Base case with X_E=30 $/kWh, X_P=1400 $/kW, and efficiency of 63% (A-CAES cost and efficiency values)	97.3	1%
Base case with X_E=30 $/kWh, X_P=1400 $/kW, and efficiency of 70% (A-CAES cost values and 10% improvement in efficiency)	97.0	0%

S-11- Comment on California's energy storage policy

Cost-reduction efforts of various BES technologies should be prioritized, among other goals, according to their economic potential. As a case in point, the California Public Utilities Commission's 2013 decision to exclude PHS plants larger than 50 MW from the California's 1.3 GW (by 2020) electricity storage mandate seems hard to defend on the basis of cost effectiveness or technical potential. The Commission argues that "the sheer size of PHS projects would dwarf other smaller, emerging technologies; and as such, would inhibit the fulfillment of market transformation goals" [39]. We strongly support the deployment storage technologies to enable learning-induced cost reductions. However, we caution that such technology-favoring policies can delay development of more cost-effective storage technologies such as PHS that seem to play a more significant role in decarbonizing electricity.

S-12- Upper bound for penetration of storage

What would be the economically optimal deployment of bulk storage provided that storage is free and ideal (*i.e.* without energy losses)? This question gives the upper bound for the market share that the BES industry could gain. According to Table S7, the ultimate market share of BES would be 31% in the best case (gas price of $10/GJ or higher and with an emissions cap of 150 $kgCO_2e/MWh$). The rest (69%) of the load is directly supplied by wind in this scenario and the contributions of GT and DZC are zero. The optimal power capacity of BES is 96% of the peak load and its energy capacity is large enough to meet the average electric load for 52 days. In the carbon-free scenario, the optimal capacity of GT and DZC turn out to be zero too, regardless of the gas price.

Table S7: Optimal characteristics of the storage and wind fleet assuming almost free (X_E=X_P=0.001) and almost ideal (efficiency=99.99%) bulk storage with a GHG emissions cap of 150 $kgCO_2e$/MWh. All other input parameters are similar to Table 2.

Gas price	**LCOE**	**BES power capacity**	**BES energy capacity**	**BES market share**	**Wind capacity**	**Wind gen. share**
$/GJ	$/MWh	% of peak load	Hours of avg. load	% of annual load supply	% of peak load	% of annual generation
5	67.9	78	1027	22	105	66
7.5	73.6	78	1027	22	105	66
≥10	76.9	96	1248	31	159	100

S-13- Sensitivity to storage efficiency

The roundtrip efficiency of electricity storage obviously varies among different BES technologies. We focused on the capital cost of storage systems as the dominant parameter impacting the economics of BES throughout the analysis. Nevertheless, A-CAES is among the least efficient BES systems; an average value of 63% compared to 75% for the generic BES system that we modeled (Table 1). In order to assess robustness of the results, we adjusted storage efficiency of the specific BES technologies in two scenarios: 75% (independent of the BES type, similar to Table 2) and the current estimates (according to values listed in Table 1). As shown in Table S8, the storage efficiency has insignificant impact on our key results. Even accounting for its low efficiency, A-CAES remains the most cost-effective technology followed by PHS.

Table S8: Sensitivity of the key results to the storage efficiency of specific BES technologies at an emissions cap of 150 kgCO_2e/MWh. Average of the values shown in bold in Table 1 are used as the energy- and power-specific capital cost of each storage technology (similar to Figure 4). Two values for storage efficiency are considered: 75% (independent of BES technology) and technology-specific values (see Table 1). All other parameters are similar to Table 2.

Parameter	**PHS**		**A-CAES**		**Pb-A**		**NaS**		**ZnBr**		**VRB**	
Efficiency (%)	75	78	75	63	75	83	75	80	75	68	75	73
X_E ($/kWh)	55		30		375		325		300		400	
X_P ($/kW)	1750		1400		550		575		1000		1250	
LCOE ($/MWh)	97.7	97.7	96.7	97.3	97.7	97.7	97.7	97.7	97.8	97.8	97.8	97.8
BES power (% of peak)	2.6	3.2	14.5	10.0	1.3	1.3	1.6	1.6	0.0	0.0	0.0	0.0
BES energy (hrs of average load)	0.4	0.5	4.6	2.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0
BES market share (%)	0.8	1.0	4.3	1.9	0.1	0.1	0.2	0.2	0.0	0.0	0.0	0.0

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