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Abstract

A strategy for feasibly and affordably achieving high electrical grid penetration (24 h/day, 365 days/yr) from electricity produced by large-scale low-cost photovoltaic (PV) systems is proposed and evaluated. It is based on oversizing PV plants without storage beyond meeting their peak daytime demand, and storing the excess energy as high-temperature heat in molten salts, from which high-efficiency steam turbines can be driven. Grid penetration levels of ~80-95% can be realized with storage capacities of only ~12 hours of average electricity demand. The feasibility reflects a striking difference between economic and thermodynamic factors. The recent dramatic decrease in PV costs more than compensates for the efficiency penalty. All components are off-the-shelf, mass-produced technologies. Hence the proposal is ready for immediate implementation. First, the thermodynamic arguments for the size and performance of such systems are reviewed. Then it is shown that the cost of electricity would be competitive with that of conventional power plants, and far better than using lithium-ion batteries. The geographic decoupling of PV fields from the storage facilities and turbines permits greater decentralization of PV fields and/or more centralization of larger storage facilities and power blocks. Because PVs collect and convert diffuse solar radiation, they are viable for areas with high global, but not direct, solar radiation, where concentrating solar thermal power plants are not feasible. It is also shown that none of the system components constitutes a limited resource. This also applies to future scenarios of much greater electricity use linked to the global transition to all-electric vehicles.

Full-length article, Word count = *,* words**

Keywords: solar, photovoltaics, molten salts, thermal storage, turbines, grid penetration

Abbreviations: A_{PV}, photovoltaic array area; CAPEX, capital expenditure; CSP, concentrating solar power; D, electricity power demand; f_{direct}, fraction of photovoltaic electricity delivered directly to the grid; GCR, ground cover ratio; H_{coll}, annual global insolation on the collectors; I_{peak}, peak global insolation; LCOE, levelized cost of electricity; N, ratio of average solar input to average electricity demand; PV, photovoltaic; t_{plant}, expected lifetime of the power plant; TS, thermal storage; η_{PV}, photovoltaic efficiency; $\eta_{PV,peak}$, photovoltaic efficiency at peak insolation; $\eta_{storage}$, conversion efficiency of photovolatic-delivered electricity to AC electricity form the steam turbine via molten-salt storage

Highlights

• Novel strategy for combining PV systems with high-temperature molten-salt storage
• Satisfying most of the 24 hr/day 365 day/yr electricity demand
• Accommodating the intermittency of solar input
• Affordable, based on off-the-shelf technologies, ready for immediate implementation
• Results based on thermodynamic, climatic and current economic data

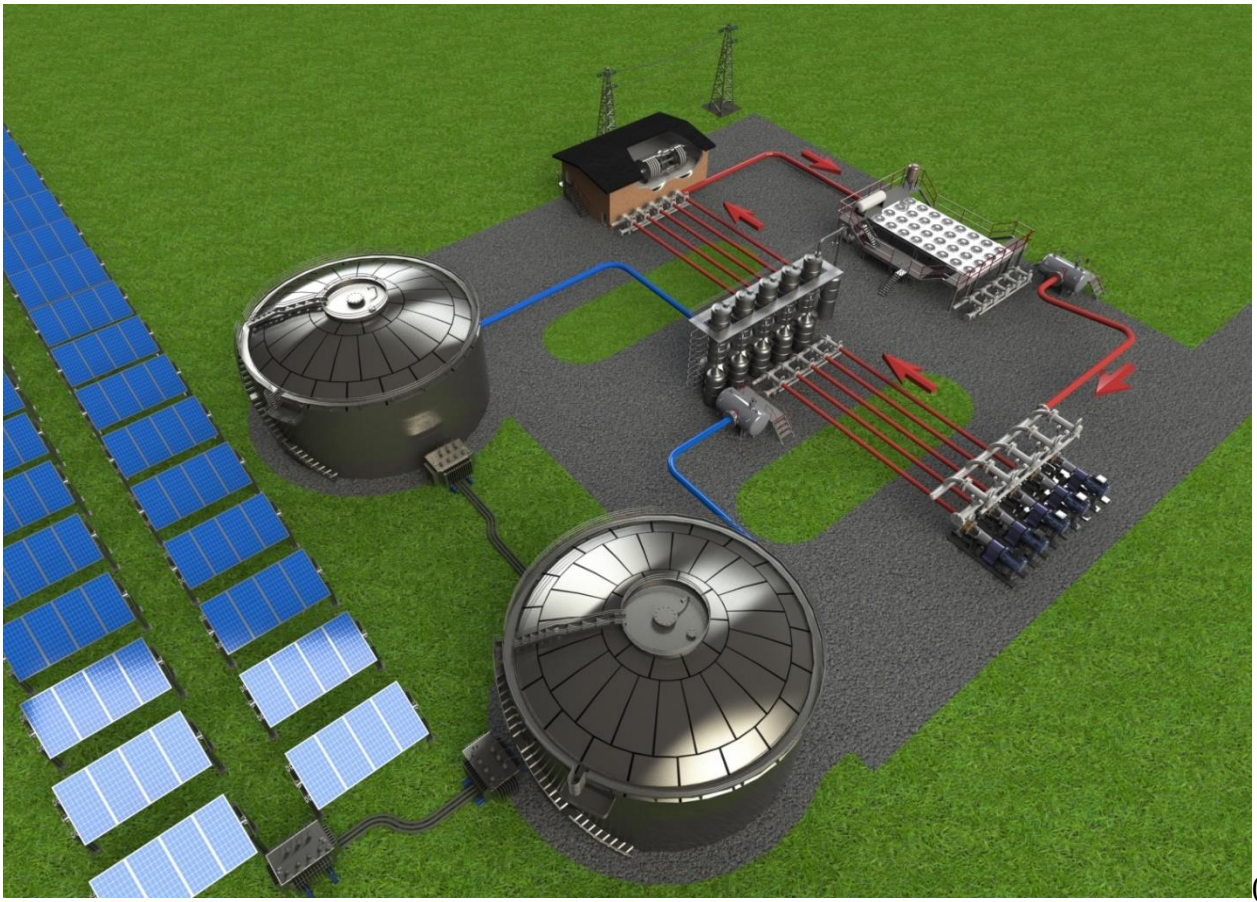
1. Introduction

A major challenge for solar electricity technologies is developing systems with energy storage which can satisfy power demand 24 hr/day 365 days/yr. Any proposal must be affordable, practical, safe, recyclable and not limited by materials availability. During the past decade, there has been an extraordinary reduction in the price of photovoltaic (PV) electricity. Installed costs have reached ~1 €/W_{peak} for utility-scale systems (≥100 MW_{peak}) [1]. The PV panels comprise only ~30% of total system cost [2]. There are already more than 500 GW_{peak} installed, increasing by more than 100 GW_{peak}/yr [3].

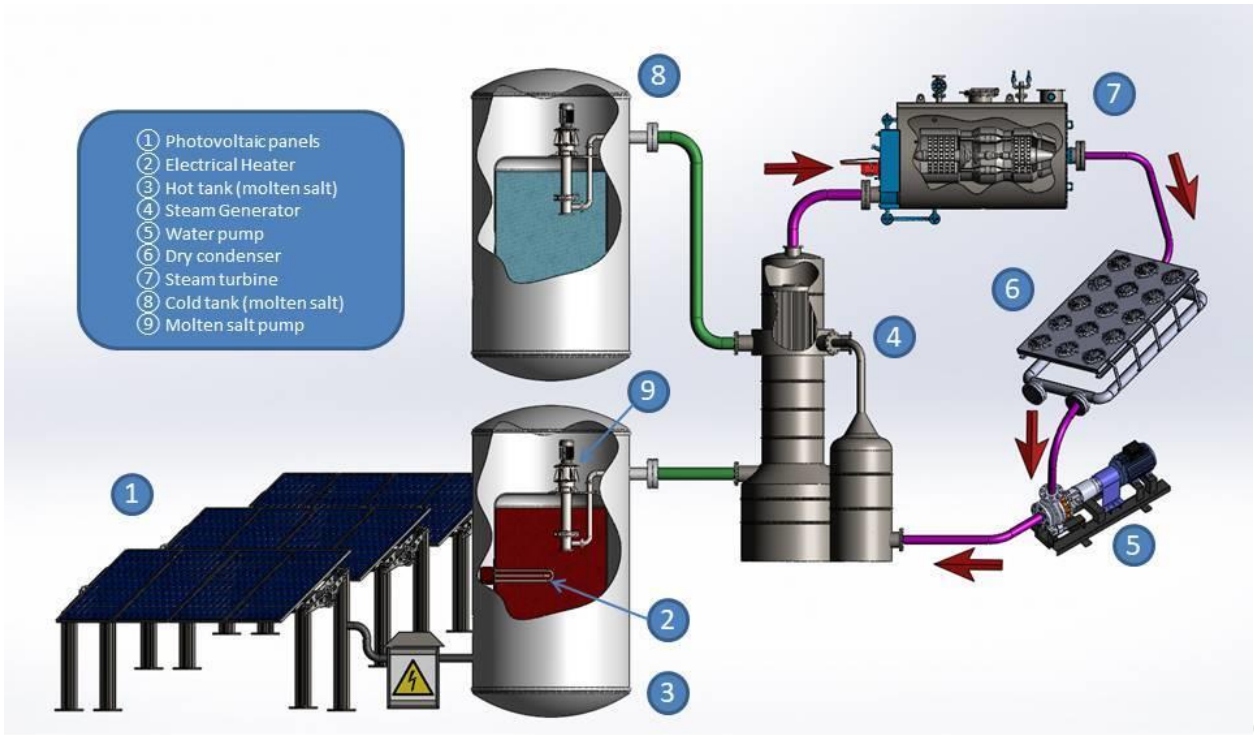
But without energy storage, high grid penetration levels cannot be attained due to the mismatch between solar availability and electricity demand. There have been several proposals for storage mechanisms [4-7]. They include thermochemical, sensible heat (in sand, rock, high-temperature fluids, concrete and/or ceramics), phase-change materials, compressed gases in caverns, hydrogen production, bio- and conventional fuel synthesis, pumped hydro, flywheels, capacitors, and batteries most notably lithium-ion batteries. However, each of these involves a key drawback, e.g., toxicity, safety, materials tolerances, risk of catastrophic failure, being highly geography-specific, very high cost now and in the foreseeable future, insufficient materials availability, or the absence of recycling technologies.

For lithium-ion batteries in particular, beyond the problem of excessive cost [8] (addressed below), efforts to develop sustainable manufacturing are still lacking, with no solution yet for recyclability [9]. Materials availability is also a problem because in large-scale production the essential metals would be depleted within less than 30 years [9,10].

Here, an unconventional but workable PV+thermal storage (PV-TS) solution (Figure 1) is described. It could be applied in areas responsible for most of the world's energy consumption. In addition, it is based on mature, affordable technologies. PV power would resistively heat molten-salt thermal storage to the temperatures (~565°C) needed for high-efficiency superheated steam turbines (~50% [11]) that would be driven by the stored heat as needed.



(A)



(B)

Figure 1. Illustration of the PV+molten-salt storage+steam turbine concept.

(A) Overall schematic. (B) Itemization of the main components. The two-tank molten-salt storage facility, the steam turbine block, secondary components and the edge of the PV field are illustrated on a far smaller scale than in the proposed power plants in order to highlight the energy flows.

2. Methods, Theory and Calculation

Converting solar-generated electricity to heat that is stored and later converted back into electricity (PV-TS) might, at first glance, seem to be a poor thermodynamic choice, especially given the option of efficient commercial lithium-ion storage batteries. The idea was not worth considering until the recent extraordinary decrease in PV prices combined with the commercial development of low-cost, affordable, safe, high-temperature molten-salt storage systems that are far less expensive than state-of-the-art large commercial lithium-ion batteries. Specifically, electrical storage capacity costs are currently no less than ~500 €/kWh for the batteries [8] (although some studies project about half that value [12]). In contrast, the corresponding cost for molten-salt storage is ~10 €/kWh [13] where account has already been been taken of the efficiency penalty for converting the stored heat into electricity.

Some previous proposals for storing solar-generated electricity thermally involve different power conversion schemes that are far more complex and commercially untested [14-16]. Recent conceptual designs for PV-TS were presented as one element in the case-specific optimization of hybrid solar power systems comprising both Concentrating Solar Power (CSP) thermal plants and PV [17-20]. Here, an in-depth, global evaluation of PV-TS is offered. Of particular interest is the possibility of achieving high grid penetration at competitive electricity costs. It is also critical to check that such large systems are not resource-limited. Rather than aiming for precise answers for specific locations, the objective here is to see if the magnitudes for PV system size, storage capacity, grid penetration levels and cost estimates are feasible.

Part of the thermodynamic estimates come from the simulation results of [8] for how grid penetration depends on the size of solar and/or wind power systems for assorted electrical storage capacities. Those results were based on simulations that used hourly meteorological data for 36 locations spanning the continental US where the average global horizontal insolation of ~2000 kWh/(m^2-yr) varies by about ±600 kWh/(m^2-yr) from the cloudiest to the sunniest regions [21]. The electricity demand was based on hourly data for the respective utilities for the year from July 2015 to July 2016. The energy generated was compared against the energy demand for each hour, at several values of energy storage capacity. The installed nameplate production capacities were estimated from representative capacity factors.

At the outset, several virtues of PV-TS should be noted, some of which are expanded upon in the sections that follow:

(1) It is ready for basically immediate implementation by combining off-the-shelf technologies. It is also a viable option for the near-term sharp increase in electricity demand that will stem from the transition to all-electric vehicles for ground transportation as well as increased standard of living.

(2) It is relevant for many regions that may have adequate global insolation but lack sufficient direct solar beam radiation where CSP is not viable because concentrators fundamentally cannot exploit diffuse solar radiation [22] whereas standard (non-concentrating) PV arrays can.

(3) It can be cost-competitive with conventional power plants.

(4) It is capable of 80-90% grid penetration for acceptable land areas, and as high as 95% for the sunniest climates.

(5) It allows the total separation (e.g., of the order of hundreds of km) of PV power generation and the storage+turbine facilities. (The same could be said of battery storage, although with non-negligible efficiency losses, first in inverting PV-generated DC power to AC for long-distance transmission, and then converting it back to DC for battery charging.) This creates the possibility of greater decentralization of the PV generators. It also can take advantage of existing rooftop and small PV installations. Greater centralization of larger storage facilities is then possible. This not only offers superior economies of scale, but can also benefit from re-using turbine blocks from decomissioned fossil-fuel and nuclear power plants.

(6) The storage temperature is not limited by the solar components. Rather, it would be limited only by the decomposition temperature of the molten salt and the corrosion temperature of the storage tank encasement and heat exchangers, which can tolerate close to 600°C. This makes it suitable for superheated steam turbines.

(7) It can incorporate gas-fired backup between storage and the turbine, ensuring superior dispatchability.

3. Results and Discussion

3.1 Thermodynamic estimates

First, the PV, storage and land requirements for achieving a given grid penetration will be estimated. That will be followed by consideration of economic factors. The grid penetration that can be attained with solar and/or wind power input, at various storage capacities, was simulated in [8] for 36 locations spanning the continental US, up to a latitude of ~50°. These results, averaged over all sites, are used in making the estimates that follow (re-cast in Figure 2).

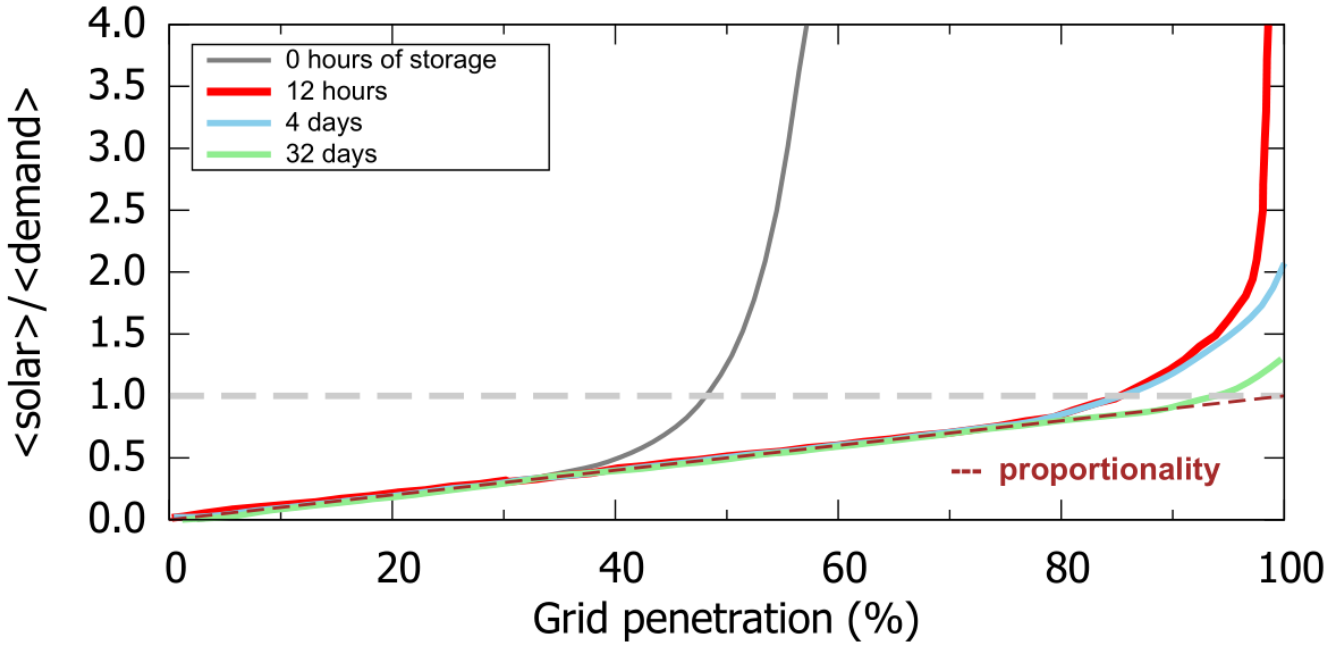


Figure 2: How grid penetration depends on the solar-to-demand ratio.
The ratio of annual-average solar electricity production to annual-average electricity demand required to provide a given grid penetration, for several values of electrical storage, averaged over 36 locations spanning the continental US (based on the data from [8] for the case with no wind power input).

Grid penetration will be proportional to the ratio of average solar input to average power demand at low grid penetration. But it must start to increase non-linearly as grid penetration approaches 100%. The results summarized in Figure 2 show that without storage, proportionality is maintained up to ~30% grid penetration. Particularly important was the finding that, with only 12 hr of storage, proportionality is maintained up to 80% (on average). Furthermore, with only a 25% increase in solar input, 90% grid penetration can be attained. For the higher-insolation locations, where proportionality can be maintained up to ~90%, an extra 25% of solar input can raise grid penetration to ~95% (again, with 12 hr of storage). An additional important finding was that adding as much as several days of storage does not noticeably increase grid penetration or decrease the necessary solar input.

In [8], results were presented for combinations of wind and solar ranging from all-wind to all-solar. Here, attention is limited to the all-solar case for several reasons. First, correlations between solar and wind availability vary far more with location than just solar availability. Second, the variances about the average are more than an order of magnitude greater for wind than for solar input. The third reason is to show that the PV-TS strategy on its own can provide high grid penetration. A comparable wind-TS (or hybrid PV+wind-TS) is a generalization for future analyses.

The input parameters and performance indices for the thermodynamic and economic estimates are listed in Table 1 below. The input parameters include the annual average:

(1) Global insolation on the collectors (static, tilt=latitude) $H_{coll} \approx 2400$ kWh/m^2 [23] (accounting for lower cosine losses than for insolation on the horizontal).

(2) PV net system efficiency based on PV array area $\langle\eta_{PV}\rangle \approx 0.15$ (for today's commercial mass-produced crystalline-silicon PV modules with 20% efficiency at standard test conditions, while accounting for the combination of cosine losses, DC-to-AC losses, more Fresnel reflective losses than at normal incidence, efficiency losses due to module heating, the dependence of efficiency on irradiance, module area being slightly less than array area, slow degradation of PV performance over system lifetime, and shading between rows of modules).

Hence the annual average PV generation ≈ 360 kWh/m^2. With a common Ground Cover Ratio (GCR) value of 0.5 [24] (GCR is the ratio of PV array area to total land area), this corresponds to 180 kWh being generated per m^2 of gross land area, i.e., 180 GWH/km^2.

The annual average (24 h/day, 365 days/yr) US electricity demand is $\langle D\rangle$ = 450 GW (4×10^6 GWh/yr). As in [8], N is defined as the ratio of annual average solar input to $\langle D\rangle$. Figure 2 illustrates that 80% grid penetration is realizable for N=0.8 (provided there are 12 hr of electricity storage, amounting to $\langle D\rangle$•12 hr = 5.40 TWh which, as shown below, would require ~95 Mtons of molten salt). The associated gross land area requirement for the PV field would be (4×10^6 GWh)•0.8/(180 GWH/km^2)=1.78×10^4 km^2. For perspective: this is ~0.2% of the continental US (9.72×10^6 km^2).

Table 1. List of input parameters and performance indices.

Input parameters	**Performance indices**
A_{PV} = PV array area (km^2)	annual-average PV generation (kWh/(m^2-yr))
$\langle D\rangle$ = annual-average electricity demand (GW or GWh/yr)	CAPEX = capital expenditure (€/W_{peak})
f_{direct} = fraction of PV electricity delivered to the grid (-)	grid penetration (-)
GCR = ground cover ratio (-)	gross land area requirement for the PV field (km^2)
$\langle H_{coll}\rangle$ = annual-average global insolation on the collectors (kWh/(m^2-yr))	land requirement per unit energy of electricity production (km^2/TWh)
I_{peak} = peak global insolation (1 kW/m^2)	LCOE = levelized cost of electricity (€/kWh)
N = ratio of average solar input to average electricity demand (-)	$LCOE_{no\ storage}$ = LCOE of the PV system without storage (€/kWh)
t_{plant} = expected lifetime of the power plant (yr)	$LCOE_{PV\text{-}TS}$ = LCOE of the PV system with molten-salt storage and turbine block (€/kWh)
$\langle\eta_{PV}\rangle$ = annual-average PV net system efficiency based on PV array area (-)	
$\eta_{PV,peak}$ = PV efficiency at peak insolation (-)	
$\eta_{storage}$ = conversion efficiency of PV-delivered electricity to AC electricity from the steam turbine via molten-salt storage (-)	

However, the PV field area must be larger than this no-storage estimate. The reason is that the energy delivered to storage - in contrast to the energy consumed at the time it is generated - requires a

factor of $1/\eta_{storage}$ more PV per kWh of electricity consumed, where $\eta_{storage}$ is the conversion efficiency of PV-delivered electricity to AC electricity from the steam turbine (via molten-salt storage). Large two-tank molten-salt storage systems have demonstrated average annual thermal efficiencies of ~99%, parasitic pumping energy included [25]. Hence $\eta_{storage}$ will essentially be that of the turbine block (~0.5).

Currently, most PV plants are sized to meet a particular peak daytime demand, with no excess generation. In the PV-TS scheme, however, where the PV area would be oversized well beyond the no-storage design, most of the PV electrical energy would be stored as heat in molten salts. And that stored heat would satisfy the power demand not only at night, but also during daytime periods of sub-peak insolation.

For example, at 80% grid penetration (N=0.8), the percentage of electricity production delivered directly to the grid - the so-called no-storage contribution - is 45% (Figure 2). The contribution from the storage system is then 35%. Then the gross land area, with 12 hr of electricity storage, is 2.56×10^4 km^2. This is less than 0.3% of the US land area. The scalable figure to keep in mind is that this corresponds to a land requirement of ~0.64 km^2 per annual TWh of electricity production. For the insolation variation across the continental US (as noted above [21]), this figure varies from ~0.5 to 0.9 km^2/TWh in moving from the clearest to the cloudiest climates.

The results from Figure 2 also show that a grid penetration of 90% is attainable for N=1.25 (e.g., by increasing the solar input), in which case the no-storage contribution is 50% and that from storage is 40%. But the total land area required increases only negligibly. Hence, despite the penalty of a factor of 2 for converting PV-stored energy into electricity, the land area requirement (and, as elaborated below, the system and electricity cost) increases by less than a factor of 1.5. (The land area for the storage facilities is negligible compared to that of the PV fields.)

Although results for 12 hr of electricity storage comprised a substantial part of the analyses of [8] (and our estimates here), results were also simulated for 0, 3 and 6 hr. The finding was that, on average, for a given ratio of average solar input to <D>, grid penetration is almost proportional to storage capacity, with the onset of a diminishing-returns relation at capacities just below ~12 hr. Results for noticeably larger storage confirmed a strong diminishing-returns relation (Figure 2).

To what extent are results calculated for the continental US applicable to other areas of the world which are responsible for most of the world's energy consumption? Beyond the US, most of the current electricity demand is in regions where the average global insolation happens to be no less than that of the US: southern Europe, Africa, India, South America, Southeast Asia, and large regions of China (the data are summarized in [26]). And the power demand is growing more rapidly in most of these regions than in the US. That would mean the PV, land and storage estimates here for high grid penetration based on US data would appear to be sufficient.

The ongoing transition to all-electric vehicles for ground transportation, plus the growth in electricity demand due to increasing population and its per-capita consumption of electricity, will result in

<D> increasing considerably. The enlarged PV fields and storage facilities will have to reflect this and can, in principle, be scaled up based on the estimates above. A more subtle aspect of these transitions is that electric vehicles are more efficient than conventional internal-combustion-engine vehicles, such that total primary energy consumption from fossil fuels, *per capita*, may actually decrease despite an increase in electricity demand [27].

A survey of primary energy consumption helps to sharpen this point. Currently, fossil fuels represent ~85% of primary energy consumption worldwide [1,28]. (The remaining 15% comprise hydroelectric, nuclear and biomass power production.) Fossil-fuel-driven electricity constitutes ~1/6th of primary energy consumption [1,28]. Ground transportation consumes ~50% more energy than the current total electricity use [11], so a transition to all-electric vehicles will more than double electricity demand. (Aviation fuel is currently less than 10% of all transportation fuel [11].)

The estimates above for the solar input and land area requirements to meet high grid penetration based on today's power demands would need to be increased proportionately. That would still leave the total land area requirement below ~1% of total available land area. As shown in [8], accommodating part of future electrical storage needs in the electric vehicles themselves (via proper coordination, infrastructure and societal cooperation) can offset only a small fraction of the required total storage requirement, and hence is not pursued here.

3.2 Economic feasibility and prospects

Typical cost metrics are total installed CAPital EXpenditure (CAPEX) in €/W_{peak} and the Levelized Cost Of Electricity (LCOE) in €/kWh.

$$CAPEX = \frac{initial\ investment}{I_{peak}\,\eta_{PV,peak}\,A_{PV}} \tag{1}$$

where I_{peak} is the peak global insolation (1 kW/m^2), $\eta_{PV,peak}$ is the PV efficiency at peak insolation and a PV temperature of 25°C, and A_{PV} is the PV array area. Because I_{peak} is basically independent of location, so is CAPEX for given PV modules and array areas. CAPEX, however, does not provide the cost of solar electricity.

$$LCOE_{no\ storage} = \frac{initial\ investment+OPEX}{H_{coll}\,\eta_{PV,peak}\,A_{PV}\,t_{plant}} \tag{2}$$

$$LCOE_{PV-TS} = \frac{initial\ investment\ in\ PV+storage+turbines+OPEX}{H_{coll}<\eta_{PV}>A_{PV}\,t_{plant}\left(f_{direct}+\eta_{storage}(1-f_{direct})\right)} \tag{3}$$

where OPEX denotes operating expenses, t_{plant} is the expected lifetime of the plant, and f_{direct} is the fraction of the PV electricity delivered directly to the grid. For utility-scale PV plants without storage, CAPEX ≈ 1 €/W_{peak} has already been commonly achieved, along with LCOE ≈ 0.03 €/kWh for the higher-insolation regions [1,2]. With LCOE being proportional to 1/H_{coll}, one would expect values as low as ~0.04 €/kWh for the cloudier climates. Indeed, in countries such as Germany where insolation levels are no higher than the cloudier parts of the US, LCOE for PV without storage has now fallen to as low as 0.04 €/kWh [29].

The individual cost contributions of molten-salt storage and the turbine block can be estimated from reports for installed CSP plants with the order of 10 hr of electricity generating capacity from molten-salt storage. Currently, they have CAPEX ≈ 5 €/W_{peak} and LCOE ≈ 0.15 €/kWh [1], with the contribution of molten-salt storage and of the steam turbine blocks each being ~10% of total cost [6,30]. This alone would increase PV-TS costs by a factor of ~2 (i.e., storage and turbines each adding ~0.5 €/W_{peak} to CAPEX and ~0.015 €/kWh to LCOE). But in addition, the PV-generated electricity that heats storage en route to electricity production introduces an efficiency penalty of $1/\eta_{storage} \approx 2$. Hence the CAPEX and LCOE for PV-TS would appear to increase by a factor of ~4. But, as noted above, more than half the energy generated by the PV-TS system is delivered directly to the grid rather than to storage, such that the actual efficiency penalty is a factor of ~1.5 rather than 2 (at 80-90% grid penetration). So LCOE for PV-TS would be ~0.09 €/kWh for the sunnier climates, i.e., ~3 times that of PV without storage. (Operation and maintenance costs constitute a basically negligible part of these quantities.) Even the higher price for the cloudier climates remains competitive with conventional power plants.

These economic and performance indices are summarized in Table 2.

Table 2. PV and CSP economic and performance indices

PV (no storage)	**molten-salt storage**	**turbine block**	**CSP with thermal storage**
$<\eta_{PV}> \approx 0.15$	storage temperature = 565-600°C	net conversion efficiency with superheated-steam = 0.5	
	cost ≈ 10 €/$kWh_{electric}$		
CAPEX ≈ 1 €/W_{peak}	CAPEX ≈ 0.5 €/W_{peak}	CAPEX ≈ 0.5 €/W_{peak}	CAPEX ≈ 5 €/W_{peak}
LCOE ≈ 0.03-0.04 €/kWh	LCOE ≈ 0.015 €/kWh	LCOE ≈ 0.015 €/kWh	LCOE ≈ 0.15 €/kWh
$CAPEX_{PV-TS} \approx 1.5$ €/W_{peak}			
$LCOE_{PV-TS} \approx 0.09$-0.12 €/kWh			

Significant factors that reduce the CAPEX and LCOE of PV-TS - but due to their large uncertainties and their being site-specific are not incorporated here - are (a) time-of-day electricity rates, (b) the value of avoided capacity, i.e., not having to build a fossil-fuel power plant as a consequence of a dispatchable solar power plant; and (c) the economic value of the favorable impact on public health and climate change.

There are no indications that the low installed and levelized costs of PV will increase (aside from small short-term fluctuations). The same can be said of molten-salt storage, where there is still room for reducing costs via economies of scale, including the fact that the PV-TS strategy permits greater centralization of fewer and larger storage facilities. Nevertheless, the economic observations here are limited solely to today's costs.

3.3 Resource limitations

The PV-TS strategy proposed here must also stand the test of adequate resource/materials availability. Are the raw materials and recycling capabilities for PV technology, molten salts, storage tanks, heat exchangers and steam turbines sufficient to accommodate the order of tens of TW of such power stations? Evidence will now be offered that the answer is yes.

PV technology: Silicon is sufficiently abundant - and the associated PV production technology is adequately mature and rapidly expandable - as not to pose a constraint [31,32]. The only concern noted so far has been the silver and glass requirement for the modules, not because of limited resource availability, but rather due to competing industries [31,32] - a planning problem rather than one of inherent materials limitations.

Molten salt storage: The "solar salt" $NaNO_3$:KNO_3 in a 60:40 mix developed for CSP has emerged as the best match because of its

(a) stability up to ~600°C, necessary for storing heat at temperatures of ~565°C toward efficiently driving superheated steam turbines,

(b) melting point of ~225-240°C [13], so solidification can be avoided with standard components, while offering a temperature range wide enough to permit substantial heat storage in a reasonable volume (290-565°C),

(c) low viscosity (hence low parasitic pumping energy) and high specific heat [33],

(d) relatively low price (<500 €/ton) [33], and

(e) safety, in terms of being non-toxic and non-flammable with possible tank leaks not being catastrophic [25].

This molten-salt storage technology, for which all large-scale commercial installations have adopted a two-tank (hotter/cooler) scheme (Figure 1), has also already proven itself to be suitable to scale-up in CSP with peak electrical power production upward of 100 MW per plant and thermal storage for the equivalent of up to ~15 hr of peak plant output [25].

Nonetheless, because the question of the availability of sufficient quantities of the solar salt for satisfying worldwide electrical demands has been raised [34], a few observations are in order. Based on the molten salt's physical properties [33] and a turbine power block conversion efficiency of ~50%, each TWh of electricity production requires ~17.4 Mtons of salt. For the current worldwide annual-average electrical consumption of ~23,000 TWh ($\langle D_{world} \rangle \approx 2.63$ TW) [1], the molten-salt storage capacity that can generate this power level for 12 hr is ~550 Mtons. Although this quantity exceeds current nitrate salt production (which is 26 Mtons of potash and 46 Mtons of soda ash per year), it is well below the level of the world reserves for the two minerals from which solar salt can readily be produced: potash (9,500 Mtons) and soda ash (24,000 Mtons) [34], both of which are commonly used in agricultural fertilizers. Moreover, the salts are largely recyclable, so that once a given level of storage is accommodated, the material needs would not grow substantially with time. Hence the quantities available to be mined - with recycling at the end of the

lifetime of storage facilities - are sufficient to satisfy increases of even an order of magnitude in electricity demand.

Nonetheless, it should also be recognized that a marked growth of the related mining industries would be necessary in order to avoid price increases that could negatively impact agriculture. Furthermore, well-planned mining facilities would be necessary in order to avoid negative environmental impact [35]. Subject to these requirements, however, the molten-salt technology would appear to be capable of providing the necessary storage capacity, now and in the foreseeable future.

For the storage tanks, the steel, concrete, ceramic and firebrick insulation used are readily available, have not exhibited corrosion or degradation in large-scale facilities to date, and do not pose a limitation for the magnitudes considered here [36,37]. Similarly, the materials and processes that go into the manufacture and operation of heat exchangers, steam turbines, electricity-distribution equipment and peripherals are not materials-limiting. This is reflected, in part, by viable plans across essentially all countries for the substantial expansion of conventional power plants and grids.

4. Conclusions

The proposed unconventional combination of PV and high-temperature molten-salt thermal storage technologies is not presented as an ultimate solution. Rather, it could be a feasible solution, ready for immediate implementation, which can be expanded rapidly and which is not in danger of being limited by materials availability. It also represents an example where the magnitude of unusually favorable economics (the ultra-low cost levels to which PVs have dropped) can override that of basic thermodynamic efficiency considerations.

The fact that flat-plate (non-concentrating) PV modules can collect and convert diffuse solar radiation means that PV-TS can be suitable across the globe for many locations with low direct-beam, but adequate global, solar radiation. This stands in contrast to CSP, which is feasible only for sun-belt regions because diffuse radiation cannot be concentrated [22]. The average total land area required for PV-TS is ~0.64 km^2 per TWh of annual electricity production.

The ability to decouple the PV fields from the storage and turbine blocks has several advantages. First, already-existing (and future) small-scale and rooftop PV installations can feed into PV-TS. This can expand its scope beyond exclusively utility-scale central systems. Second, on a regional scale, there can be fewer, larger storage tanks and turbines (for the same total storage and generating capacities) with the benefit of economies of scale. And third, large steam turbines already operating in fossil-fuel and nuclear power plants that are being decomissioned can be re-used in PV-TS, lowering capital costs. (It should be noted, however, that turbines from decomissioned power plants are usually not high-efficiency superheated-steam units, so the estimates above would need to be scaled accordingly.)

The inherently dilute power density of solar radiation translates into large solar fields: currently ~0.2% of total land area on average which, even for future scenarios with greatly increased electricity demand, would correspond to reasonable land requirements.

The estimates presented here - where 80-95% grid penetration appears feasible - are based on combining the powerful simulation results of [8] with basic PV-TS performance considerations. The findings of [8] were restricted to the continental US, but covered climatic conditions and utility demand profiles that can be applied to many regions accounting for the majority of the world's current and future energy consumption. For regions with average insolation that is higher than the US [26] - some of which also happen to have electricity demand profiles that are better correlated with solar availability [1] - the PV and storage requirements per TWh of electricity consumption will be lower. Furthermore, the transition to all-electric vehicles may increase the fraction of electricity demand during daytime hours, when much of the battery charging will be performed. This would also translate into less PV and less storage being needed per TWh of electricity consumption.

High-consumption regions with appreciably lower global insolation [26] and often differing electricity-demand profiles [1] such as Russia, the former Soviet republics, Japan, northern Asia, and mid-to-northern Europe, will present non-negligibly higher PV areas and storage capacities. But they also happen to possess a large wind-power potential that can be interfaced with molten-salt storage - case-specific evaluations for future studies.

The size and operation of solar power plants with storage which could close the gap for the remaining 5-20% of grid penetration become quite sensitive to specific aspects of local power demand profiles and climatic data. Each extra percent of grid penetration comes at the price of rapidly increasing system size (Figure 2) and hence poorer economic feasibility. They are therefore a regime not analyzed here, reinforced, in part, by the availability of natural-gas-fired power plants. Given sizable future increases in electricity demand that will stem from the transition to all-electric vehicles and increased standard of living, the ability to greatly reduce the associated fossil-fuel consumption currently devoted to electricity generation could be viewed as a significant opportunity.

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Author contributions

All the authors contributed equally to this work.

Declaration of Interests

The authors declare no competing interests.

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