

How to judge whether supporting solar PV is justified

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How to judge whether supporting solar PV is justified

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Abstract

Renewable electricity, particularly solar PV, creates external benefits of learning-by-doing that drives down costs. If eventually economic, these technologies will thereafter create social value by reducing carbon emissions with value greater than the cost of abatement. This paper sets out a method for assessing whether a trajectory of investment that involves initial subsidies is justified by the subsequent learning-by-doing spillovers and whether it is worth accelerating current investment rates. Given current costs and learning rates, accelerating the current rate of investment appears globally socially beneficial, particularly if that investment is deployed in high insolation locations.

1 The case for subsidies

The *Global Apollo Programme* (King et al., 2015) calls for a global effort to combat climate change, including support to drive down the cost of zero-carbon generation. Given the range of different zero-carbon options (nuclear, wind, solar PV, etc.) how does one decide when one option merits continued support and when to abandon that technology and concentrate on others? The main case for supporting different renewable energy technologies is that their deployment drives down costs through learning-by-doing and induced technical progress. Figure 1¹ shows this for the price of silicon PV modules, but there are many similar graphs available (e.g. Fraunhofer,

*Faculty of Economics, University of Cambridge, Director, EPRG. This paper was prompted by Neuhoff (2008), who was pessimistic about the social profitability of PV when its cost was much higher, but noted that increasing current investment might relax constraints on future investment rates, which conferred an additional and potentially large extra benefit. I am indebted to insightful comments from Rutger-Jan Lange.

¹Source: Delphi234 - Own work, CC0, <https://commons.wikimedia.org/w/index.php?curid=33955173>. The straight green line predicts that modules decrease in price by 20% for every doubling of cumulative shipped modules. The other line (with squares) shows world-wide module shipments vs. average module price. The data are from ITRPV 2015 edition and can be updated to 2015 with ITRPV (2016).

2016). If technology developers can see a viable market for their products, they will be encouraged to research, develop, test, and, if the results are promising, scale up production and drive down costs. The resulting cost reductions are typically measured by the learning rate – the proportional drop in cost per unit for a doubling of the installed capacity. While there is uncertainty not only about past learning rates (Rubin et al., 2015) but clearly about future rates² and even their attribution to deployment or R&D (Jamash, 2007; Nordhaus, 2014), the learning rates for some technologies like solar PV seem impressive. ITRPV (2016), which as an industry source may be more optimistic, claims the continuation of a 21.5% learning rate for PV modules from cumulative production of 227 GW_p.³ This is consistent with Rubin et al. (2015) for one-factor models that attribute all cost reductions to deployment, while two-factor models that separately identify R&D lower this figure to 12% (Rubin et al., 2015, table 1). On-shore wind has a lower one-factor mean learning rate of 12% and a two-factor learning rate of 9.6%. The 2015 annual rate of PV installation was 50 GW_p or 28% of the installed base, which alone could cause a current cost reduction of 6%.

These learning benefits are hard for the developers to capture (the solar PV and wind turbine markets are intensely competitive) and so they primarily benefit subsequent installations. Even if the improvements could be patented and licensed, there would be a strong case for making these technologies available without a license fee to encourage their take-up and resulting climate change mitigation, so directly supporting deployment (and R&D) is preferable to license fees. These learning benefits therefore justify support.

The second case for support extends to all low or zero-carbon technologies in the absence of an adequate, durable and credible carbon price, and can be addressed either directly by a Carbon Price Support (CPS, as in Britain),⁴ somewhat indirectly and more bluntly through emissions performance standards that discourage investment in carbon-intensive generation, or in a second-best world, by subsidizing the output of low-carbon generation by the short-fall in the efficient price set by more carbon-intensive generation.

²Which may be better modelled as an assembly of components each of which is subject to different learning rates – see Rubin et al. (2015) and references therein.

³Subscript _p refers to peak output; average output can be above 25% in favoured locations like the South-West of the US, or as low as 10% in Northern Europe (ITRPV, 2016; EPRI, 2016). In figure 1, from data in ITRPV (2016), the green line shows Swanson’s law, a 20% decrease in price for every doubling of cumulative shipped photovoltaics. The blue line shows actual world wide module shipments vs. average module price, from 1976 (\$104/W_p) to 2015 (\$0.58/W_p). Prices are in 2015 dollars. The actual decrease has been slightly greater than a 20% decrease with each doubling.

⁴The CPS raises the cost of CO₂ emissions from electricity generation up to a pre-specified level. The additional carbon tax (added to the ETS price) was set at £14.86 per tonne CO₂ for 2016/17 (HoC, 2016).

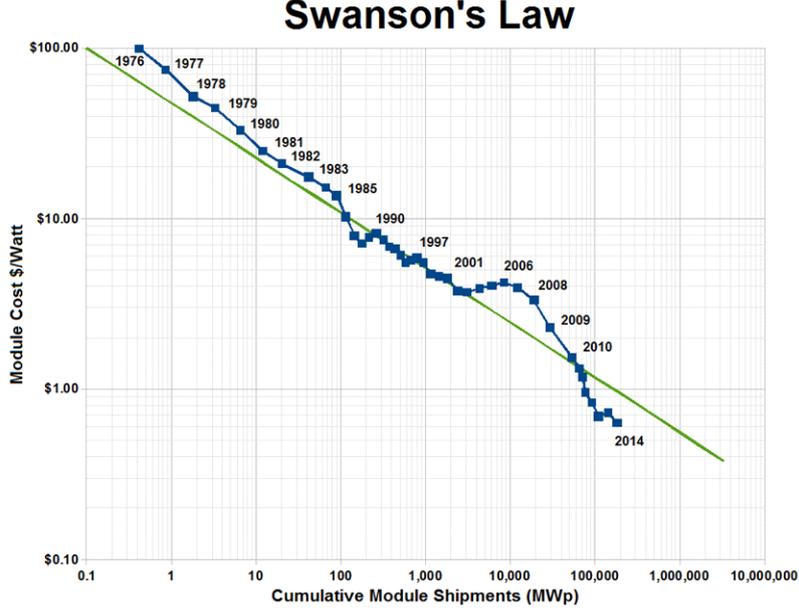


Figure 1: PV Module price reductions

2 The example of PV

Fraunhofer (2016) suggests a fairly steady learning rate of 23% since 1980, consistent with the one-factor rate of 21.5% from ITRPV (2016) and (EC, 2009), which reports a steady learning rate of 22% for PV since 1979. The one-factor learning model has the unit cost at date t , c_t , given by

$$c_t = aK_t^b, \text{ so } \frac{\Delta c}{c} = (1 + \Delta K/K)^b - 1, \quad (1)$$

where K_t is cumulative production of the units to date t , and b measures the rate of cost reduction. The learning rate, λ , is the reduction in unit cost for a doubling of capacity, so setting $\Delta K = K$ in (1), $\lambda = -\frac{\Delta c}{c} = 1 - 2^b$. For $\lambda = 22\%$, (ITRPV, 2016) $b = -0.358$. The factor b can then be used to estimate the future unit cost from (1). Over longer periods of time, it is implausible to assume that learning rates can continue until costs fall almost to zero. Equation (1) can be modified to allow for an irreducible minimum production cost, c_m :

$$c_t = c_m + aK_t^b = c_m + (c_0 - c_m)\left(\frac{K_t}{K_0}\right)^b. \quad (2)$$

Initially, $\Delta c/(c - c_m) \simeq \Delta c/c$, and the estimated learning rate will not be much affected by this change, but at lower costs the difference can become appreciable.

2.1 Predicting unit costs

ITRPV (2016) states that the global average module price in 2015 was US\$ 0.58/W_p, and that the installed base at the end of 2015 was 234 GW_p.⁵ However, the module for large (>100kW systems) in the US and Europe is only 55% of the total system cost (excluding “soft costs”), so the full system cost was then US\$ 1.05/W_p and the assumed system price US\$ 1,090/kW_p. The module cost is forecast to fall to \$US 0.26/W_p by 2026 when it will only be 36% of the system costs, which in total fall to 68% of its 2015 value or to US\$ 0.72/W_p. This implies that the Balance of System (BoS) costs are projected to remain relatively constant at around US\$ 0.46/W_p, although others predict that these costs should fall with experience, R&D and learning.

NREL (2016) gives US cost estimates for the total installed cost of utility-scale installations for Q1, 2016, based on a module price of US\$(2016) of 0.64/W_p, and the full system cost, including all the installation, permitting and grid connection costs and (expensive) US labour costs, to give US\$ 1.14/W_p for a fixed-tilt 100 MW array in Oklahoma (the cheapest state, with non-unionised labour). The cost of a one-axis tracking unit there would be US\$ 1.19/W_p, and tracking is cost-effective given the resulting higher capacity factor (CF, often measured in full hours per year, or kWh/kW_p/yr). Installation costs should be lower in countries with lower labour costs as the US labour element is US\$ 0.16/W_p. If we take the average module price (rather than the US figure) and halve the US labour cost but estimate for a tracking system, then the 2015 starting value would be US\$ 1.05/W_p. From now on we use a learning rate for the whole system, not just the module, and consider different possible values.

Estimates of the levelized cost of energy (LCoE) depend critically on location (insolation) and local installation costs. ITRPV (2016, fig 45) forecasts costs for 2,000 kWh/kW_pyr (23% capacity factor, CF, but this appears to be for tracking panels)⁶ as US\$ 44/MWh, and this can be achieved in sunny areas of the US. Already some Power Purchase Agreements in the US have been signed for 20 years at less than US\$ 40/MWh (indexed, without “meaningful tax state credits”, EPRI, 2016, fn 6). European capacity factors (CFs) are lower and 1,000 hrs/yr or 11.4% CF gives current LCoE costs of US\$ 87/MWh. Estimating capacity factors is not straightforward as it depends not only on location but also the size of the array.⁷ The data that

⁵Prices may be above or below costs. The US data discussed below are built up from cost components and will be higher than costs in China. Properly speaking, the costs relate to a level of cumulative production that would be lower than the end of the year value, so future cost reductions are slightly under-estimated.

⁶Bolinger et al., (2016) reports that over half the US utility-scale PV installations are tracking. The median CF for all types together in 2014 was 25.7%, and the average was 25.5% with a range from 16% to 30%. Tracking appears to increase CF's by 5.9% in high insolation areas, but clearly increases cost. The main determinant of CF is the global horizontal irradiance.

⁷See <http://euanmearns.com/solar-pv-capacity-factors-in-the-us-the-eia-data/> that discusses the very high EIA CFs, which in California exceed 28%. Smaller roof-top arrays may have CFs of 3% less. For our purposes grid-scale

can be downloaded⁸ suggests lower CFs for fixed-tilt arrays, presumably as it refers to smaller panels, and hence understates utility-scale performance. For the estimates presented below we therefore take the 2015 unit cost as \$1,050/kW_p.

2.2 Estimating the spill-over benefits of PV capacity

Investment now lowers future installation costs, and hastens the date at which PV might become cheaper than fossil generation. If we were to take the cost reduction model of (1) or (2) at face value regardless of the rate of investment and hence the rate of growth of experience, then the globally optimal solution would be either to do no further investment (if PV will never be sufficiently competitive), or to accelerate investment at the maximum possible rate, as the cost of delivering learning is lowest when the stock of knowledge is lowest. The cost of doubling cumulative production from 1 GW is far lower than doubling it from 100 GW. In mathematical terms, the optimal solution would be ‘bang-bang’ – to immediately jump to the optimal cumulative production that delivers competitive PV from here on.

As Neuhoff (2008) cogently argued, this strategy is implausible for at least two reasons. The first is that scaling up PV production capacity takes time, and second, more fundamentally, learning itself takes both experience and time for that learning to disseminate and be incorporated into best practice. Indeed, the two-factor model suggesting the importance of R&D would likely find it hard to discriminate between R&D and the elapse of time for dissemination. It is often remarked that Silicon Valley is more innovative than Japan because of the high turnover of staff carrying their knowledge to competing firms, in contrast to life-time employment practices in Japan that make such people-mediated knowledge transfer less likely.

The implication is that even if current PV investment is not attractive, it may be (globally) desirable to accelerate that investment to the point that absorption becomes an issue and the rate of innovation or cost reduction appears to falter. In practical terms that means looking for the highest plausible rate of growth of cumulative production, and checking that this trajectory of investment in PV is justified – if it has a positive present discounted value (PDV) when properly accounting for the social cost of the fossil generation displaced including the social cost of CO₂. As a check, it will appear to be socially profitable to accelerate this investment if a small increase in investment now has a positive impact on the PDV of the trajectory, which is an indication that the constraint limiting investment is either industrial capacity to produce, or the fact that further acceleration would no longer deliver the assumed learning spill-overs.

PV CFs are more relevant.

⁸Data can be downloaded from <http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/> which gives both irradiance in kWh/m²/d and in kWh/yr from 1 kW_p panels.

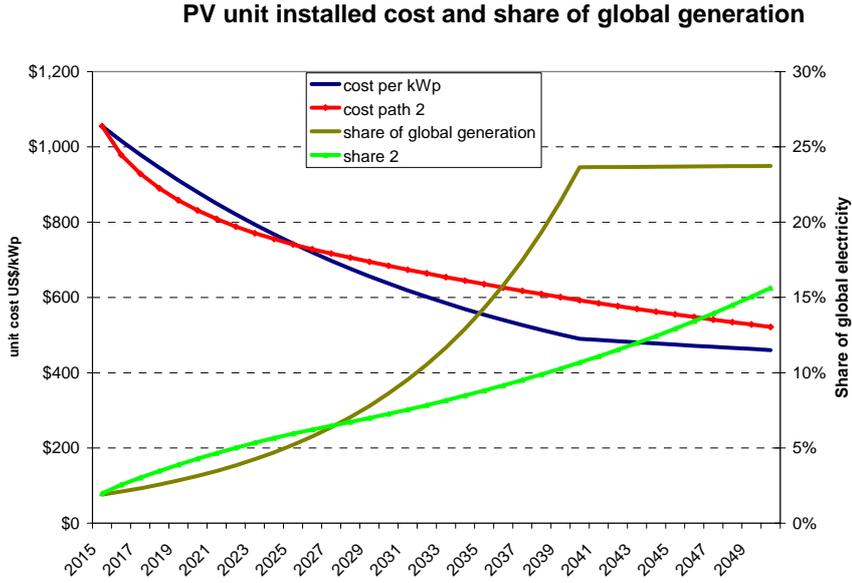


Figure 2: PV system cost and share trajectories

This ‘constrained optimal’ trajectory will be determined by the amount of capacity added each year, from which one can estimate the cost of additional units as a function of cumulative *gross* investment. Note that the installed stock at any moment will be less than cumulative gross investment as PV arrays only have an estimated life of 25-30 years. Properly computed learning rates should be based on cumulative production of PV modules as in fig.1, not the current installed capacity.

The default trajectory for PV assumed in most of the calculations below assumes a learning rate, $\lambda = 22\%$, $c_m/c_0 = 25\%$ and a growth rate of PV, $g = 15\%$ until 2040, after which the growth slows to that of global electricity and penetration ceases to rise. The capacity factor, $h = 2,000$ hrs/yr equivalent to a highish value of 22% and the initial cost is $\$1,050/\text{kW}_p$. Fig. 2 shows the implied unit system cost and share of PV in global electricity production. The second pair of graphs is based on recent projections by ITRPV (2016), which notes that cumulative module shipments were 234 GW by the end of 2015, forecast to rise to 850 GW by 2024. Fig. 2 takes the actual capacity in 2015 as 234 GW (assuming that the earlier capacity now being decommissioned was negligible at that date, and assumes that the installed capacity grows by initially 70 GW/yr rising slowly to reach 75 GW/yr by 2027 and thereafter growing at 5% faster than global electricity. Replacement investment (the actual investment 25 years earlier) raises gross investment above this capacity expansion and it is gross investment that drives cost reductions. Global electricity forecasts are taken from EIA (2016).

3 Modeling the benefits of PV investment

Let y_t be PV output at date t , I_t the current gross investment in PV capacity, whose unit cost is c_t and total cost is C_t , k_t be PV capacity, which degrades at rate δ , and L be its lifetime (assumed to occur before it has fully degraded as other components fail or become obsolete). PV generation is $h_t k_t$, where h_t is the equivalent full hours output per year of PV installed at date t and will depend on location. The rate of PV installation, I_t , grows at rate g until date T . Total accumulated production of PV units is K_t , and this determines the level of accumulated learning to date t according to (2). The amount of age v capacity remaining at t is $I_{t-v}e^{-\delta v}$, so if $\psi(x, T) = (1 - e^{-xT})/x$,

$$\begin{aligned} I_t &= I_0 e^{gt}, \quad K_t = \int_{-\infty}^t I_u du = K_0 e^{gt} = I_t/g, \\ \frac{dk_t}{dt} &= I_t - I_{t-L}e^{-\delta L} - \delta k_t, \end{aligned} \tag{3}$$

$$k_t = \int_{t-L}^t I_u e^{gu} e^{-\delta(t-u)} du = I_t \psi(g + \delta, L), \quad \frac{k_t}{K_t} = g \psi(g + \delta, L) < 1. \tag{4}$$

$$c_t = c_m + (c_0 - c_m)(K_t/K_0)^b = c_m + (c_0 - c_m)e^{gbt}, \quad y_t = h_t k_t.$$

$$C_t = c_t I_t = [c_m + (c_0 - c_m)e^{gbt}] I_0 e^{gt}. \tag{5}$$

Equation (3) shows that the change in current installed capacity is the current investment, *less* the amount retired that was installed L years before, and the amount that degrades in the current year, and can be derived from the equivalent formulation in (4).

The first question to address when considering whether it is worth subsidizing current PV is to estimate the value of future cost reductions, discounting at the social discount rate, r . Future investment costs are $c_t I_t$, given by (5). A change in current investment, dI_t , will change all future values of K_u , $u > t$, by dI_t , so the net present discounted cost of this change at date $t = 0$, A_0 , assuming steady growth until date T ,⁹ will be:

$$\begin{aligned} A_0 &= \int_0^T I_t (c_m + (c_0 - c_m) \left(\frac{K_u}{K_0}\right)^b) e^{-ru} du, \\ \frac{dA_0}{dI_0} &= c_0 + \int_0^T b(c_0 - c_m) \left(\frac{K_u}{K_0}\right)^{b-1} \frac{I_0}{K_0} e^{-(r-g)u} du \\ \frac{1}{c_0} \frac{dA_0}{dI_0} &= 1 + \frac{bg(1 - c_m/c_0)(1 - e^{-(r-bg)T})}{r - bg}, \end{aligned}$$

where I_0/K_0 has been replaced by g .¹⁰ As $b < 0$, the second term is negative, indicating future

⁹Continued growth at higher than the overall growth in electricity demand is infeasible, so truncating at date T represents a compromise that understates the spill-over, though for large T the effect will be muted. Similarly a lower average g than the current rate will understate the NPV.

¹⁰ I_u for $u > 0$ is unchanged, but I_0 is changed.

cost reductions. As a fraction of the current investment cost, this spill-over *benefit* at date zero is

$$\left(1 - \frac{c_m}{c_0}\right) \frac{(1 - e^{-(r-bg)T})}{1 + r/(-bg)}. \quad (6)$$

To give a sense of magnitude, with a learning rate $\lambda = 22\%$, $b = -0.358$, $g = 15\%$, $-bg = 5.37\%$, $c_m/c_0 = 25\%$, $r = 3\%$, $T = 25$, the learning benefit would be 42% of the cost (and increasing in both the learning rate, λ , and g). At earlier periods (date $-v$) the first term in (6) would be $1 - c_m e^{-bgv}/c_0$, and the numerator in the second term would be $1 - e^{-(r-bg)(T+v)}$, both increasing in v . In the limit for large v , the learning benefit would tend to $(1 + r/(-bg))^{-1}$, or 64% with these figures. This can be summarised in a proposition:

Proposition 1 *If at any date on a previously steady growth PV trajectory, continued investment is justified, it will have been so for all previous dates*

Proof. *The spillover benefits at date $-v$ compared to those at the reference date zero are*

$$\left(1 - \frac{c_m e^{-bgv}}{c_0}\right) \frac{1 - e^{-(r-bg)(T+v)}}{1 + r/(-bg)} > \left(1 - \frac{c_m}{c_0}\right) \frac{(1 - e^{-(r-bg)T})}{1 + r/(-bg)}$$

for all $v > 0$. ■

In order to justify this as a subsidy, it must also be the case that the whole trajectory is socially profitable – it is not enough just to be able to reduce future costs if the technology never achieves adequate future success in the market place. That will depend on the value of the fossil fuel displaced, including the carbon benefit. The derating factor of PV, τ , is the amount of derated fossil capacity needed to meet the reliability standard that can be avoided, in total τk_t ($0 \leq \tau < 1$). In winter-peaking systems PV output is zero in peak hours so $\tau = 0$, and the only benefit is the energy and carbon cost avoided. In summer peaking systems (with high air-conditioning load), $\tau > 0$, perhaps as high as 30% with low PV penetration.

If the carbon *price* paid per MWh¹¹ of fossil generation at date t is Γ_t , which developers expect to rise at rate I , and the PV output-weighted annual average extra variable fossil cost (fuel + the excess of the fossil variable O&M over the PV variable O&M *less* any extra balancing costs required to manage the PV) is p_t , both per MWh, then the profit of the PV output is $h_t(p_t + \Gamma_t)$ per year per MW_p PV. Ignoring the spill-over of learning benefits, and granting PV a capacity credit of τP_t per unit of capacity per year, where P is the payment per unit per year for de-rated capacity,¹² the net present discounted cost of a unit investment at date zero when discounting

¹¹Subscript $_e$ refers to the carbon content of the electricity generated. The carbon price is the one the developers face, not necessarily the social cost of carbon, γ_t .

¹²This is most readily determined in a capacity auction, or is estimated as the net Cost of New Entry, net of sales in competitive energy and ancillary service markets.

at a commercial discount rate R is:¹³

$$f_0 = c_0 - m_0, \quad m_0 = \int_0^L e^{-\delta u} [h_u(p_u + \Gamma_0 e^{Iu}) + \tau P_u] e^{-Ru} du. \quad (7)$$

If p_u and τP_u are constant

$$m_0 = (hp + \tau P)\psi(\delta + R, L) + h\Gamma_0\psi(\delta + R - I, L).$$

If this is positive the investment will need to be subsidized to persuade developers to install the capacity, but if it becomes negative, the developer needs no inducement (other than perhaps a long-term contract to assure the future energy and carbon value; under most capacity market designs the capacity payment would take the form of a long-term contract). This can be evaluated and the results for various parameter values are shown in Fig. 3 below. The examples provided tell us that solar PV is already commercially viable without subsidy in high insolation areas ($h = 2,000$ hrs/yr), but only with an adequate carbon price and reasonably low cost of capital (Fig. 3, col B vs. Col A). In Northern Europe subsidies (or higher energy prices) would still be necessary even with cheap finance and a reasonably high carbon price (Fig. 3, col C).

3.1 Evaluating global learning benefits

One can imagine two possible ways of organizing the *Global Apollo Programme* (King et al. 2015) to deliver the PV deployment programme. The least cost solution would be to concentrate all deployment in locations requiring the least subsidy cost at each moment. This would likely be in the highest insolation areas provided the PV displaced fossil fuels (and the default assumed is gas, but if coal is displaced, as in China, lower insolation could be consistent with low subsidy rates). The more likely alternative is that the *Global Apollo* agreements require each country to undertake its fair share of the subsidy and would likely concentrate support within its own borders, unless some regional pooling could be arranged.

In the first case h would be initially high, but as good sites are preferentially used first, it can be expected to decline over time as less favoured locations are developed when the high insolation areas become saturated, driving down the local wholesale price. The annual average net value of displaced energy, p_t , could also fall as areas of high PV depresses local nodal prices, possibly to the extent of driving prices down to zero in some hours, while the cost of balancing, flexibility services, storage and interconnection increases, again lowering the average fossil displacement value, p_t (Newbery, 2016). Similarly, the value of PV capacity, τP_t , will also fall as additional

¹³The assumption is that the developer takes on marketing risk but will be provided with the equivalent of a capital subsidy, e.g. via a fixed price per MWh sold up to 20,000MWh/MW_p. The discount rate is then the weighted average cost of capital given the various contracts for output and capacity designed to minimise the cost of the support.

Figure 3: Profitability of solar PV for various parameters

parameters		A	B	C	D	E	F	G	H	I	J
PV learning rate %	λ	22%	22%	22%	22%	22%	22%	22%	20%	22%	18%
min cost/current PV cost	c_m/c_0	25%	25%	25%	25%	25%	25%	25%	25%	30%	25%
PV annual degradation % p.a.	δ	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
PV growth rate % p.a.	g	15%	15%	15%	15%	15%	15%	15%	15%	15%	18%
CF kWhrs/kWyr hrs/yr	h	2,000	2,000	1,000	1,200	2,000	1,200	1,000	2,000	2,000	1,200
decline in hrs % p.a.	ζ	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
WACC for PV % pa	R	7%	5%	4%	5%	7%	7%	5%	7%	7%	5%
displaced net energy value	ρ	\$35	\$35	\$60	\$35	\$35	\$35	\$36	\$35	\$35	\$35
rate of decline of price % p.a.	π	0%	0%	0%	1%	1%	0%	0%	1%	1%	1%
market price CO2 \$/MWh	Γ	\$5	\$2	\$10	\$5	\$5	\$5	\$5	\$5	\$5	\$5
PV de-rating factor	τ	10.0%	10.0%	0.0%	10.0%	10.0%	5.0%	5.0%	10.0%	10.0%	10.0%
results											
PDV PV market revenues	m	\$993	\$1,110	\$1,058	\$654	\$861	\$587	\$611	\$861	\$861	\$654
private value of PV /kWp	f	-\$57	\$60	\$8	-\$396	-\$189	-\$463	-\$439	-\$189	-\$189	-\$396
subsidy cost of trajectory	F_0/I_0	-\$54,183	-\$69,155	-\$78,594	\$27,706	\$1,590	\$4,351	\$1,875	\$6,183	\$6,581	\$48,341
external value of trajectory	S_0/I_0	\$7,379	\$13,978	-\$1,809	\$3,732	\$6,220	\$4,427	\$3,689	\$6,220	\$6,220	\$5,339
social value of trajectory	V_0/I_0	\$61,562	\$83,132	\$76,785	-\$23,974	\$4,631	\$76	\$1,814	\$37	-\$360	\$43,002
social value of increasing IO	dV_0/I_0	\$604	\$826	\$473	\$351	\$719	\$111	\$113	\$693	\$690	\$341

PV competes less successfully with existing PV. All these elements could be given decreasing time trends:

$$h_t = h_0 e^{-\zeta t}, \quad p_t = p_0 e^{-\pi t}, \quad \tau P_t = \tau_0 P_0 e^{-\xi t}, \quad (8)$$

so that (7) can be explicitly written and evaluated on constant growth paths:

$$\begin{aligned}
 f_t &= c_t - \int_t^{L+t} e^{-\delta t} [h_0 e^{-\zeta t} p_0 e^{-\pi t} + h_0 e^{-\zeta t} \Gamma_0 e^{I t} + \tau_0 P_0 e^{-\xi t}] e^{-R t} dt, \\
 f_t &= c_t - h_0 [p_0 e^{-(\zeta+\pi)t} \psi(\delta + R + \zeta + \pi, L) + h \Gamma_0 e^{-(\zeta-I)t} \psi(\delta + R + \zeta - I, L)] \\
 &\quad - \tau_0 P_0 e^{-\xi t} \psi(\delta + R + \xi, L).
 \end{aligned} \quad (9)$$

Fig. 3 lists the parameters that are allowed to vary in the calculations reported below. Col A is the base case and individual differences in parameters are highlighted. (In all calculations, $L = T = 25$ years, $r = 3\%$, $I = 0.5\%$, $i = 1.5\%$, $P = \$75/\text{kWyr}$, $\gamma = \$10/\text{MWh}_e$, $\xi = 0$ to reduce the number of variations).

The social benefit of providing this stream of subsidies assumes that the future PV gross profits once the PV costs become competitive with fossil fuel are counted as social benefits. In addition, some of the price decline that affects the commercial viability of PV would not have occurred in the absence of the subsidy programme and so are additional spillover benefits reaped by consumers. The simplest assumption is that without PV, fossil prices would not decline, so all of the price decline is a consumer benefit. The other adjustment to make is that the carbon price that developers face may understate the global social cost of carbon, and the rate at which

developers assume the carbon price will be allowed to rise may again differ from that of the social cost. As before, we use capitals to denote the carbon market *price*, Γ , and an expected rate of growth I , and lower case for the social values, γ and i .

The total net social *benefit* of this trajectory, discounting at a social discount rate of r , is then the social gains accruing to other parts, S_0 , *less* the cost of the required subsidies, F_0 :

$$\begin{aligned} V_0 &= -F_0 + S_0, \text{ where } F_0 = \int_0^T f_t I_t e^{-rt} dt, \text{ and} \\ S_0 &= \int_0^T h_t k_t [(p_0 - p_0 e^{-\pi t}) + \gamma_0 e^{it} - \Gamma_0 e^{It}] e^{-rt} dt. \end{aligned} \quad (10)$$

The PDV of the required unit subsidy, F_0/I_0 , is:

$$\begin{aligned} F_0/I_0 &= c_0[(c_m/c_0)\psi(r-g, T) + (1-c_m/c_0)\psi(r-(1+b)g, T)] \\ &\quad - h_0[p_0\psi(\delta+R+\zeta+\pi, L)\psi(\zeta+\pi+r-g, T) \\ &\quad + \Gamma_0\psi(\delta+R+\zeta-I, L)\psi(\zeta+r-I-g, T)] - \tau_0 P_0\psi(\delta+R+\xi, L)\psi(\xi+r-g, T). \end{aligned}$$

The remaining corrective social benefits can also be evaluated replacing k_0/I_0 by $\psi(g+\delta, L)$:

$$\begin{aligned} S_0/I_0 &= h_0\psi(g+\delta, L)[p_0\{\psi(\zeta+r-g, T) - \psi(\zeta+r+\pi-g, T)\} \\ &\quad + \gamma_0\psi(\zeta+r-g-i, T) - \Gamma_0\psi(\zeta+r-g-I, T)]. \end{aligned}$$

The two components of V_0/I_0 and their sum are shown for various parameter values in Fig. 3. (The highlighted values indicate changes from the base case shown in Col A. If $\xi > 0$, all benefits will be somewhat decreased.) The base case shows that while privately unprofitable without subsidy, F_0 is negative, so providing the future fossil savings can be clawed back or counted as social gains, the trajectory has positive social value even ignoring the spill-overs, S_0 . Allowing for declining h_t and p_t , ($\zeta = \pi = 1\%$), Col E shows unsubsidized PV unprofitable (at $R = 7\%$) but socially profitable. Lower insolation ($h = 1,200$ hrs) requires a lower market weighted average cost of capital, WACC, ($R = 5\%$) to be socially profitable (Col D). Lowering the learning rate λ , (Col H vs Col E) lowers social profitability, as does raising the minimum PV cost (Col I) in this case making the trajectory unviable, but see section 2.3 below. Rasing the rate of growth, g , can offset quite a large fall in λ , (col J).

3.2 A decentralized *Apollo Programme*

If the funds for supporting PV cannot be directed to developers with the least required subsidy across the globe, then at best regional support programmes could achieve this regionally with some loss of average insolation, lowering the average value of h , but perhaps, through using a wider set of countries, decreasing the rates of cannibalization. We can test this by setting

$h = 1,200$ hrs, $\zeta = \pi = \xi = 0$ in (8), and an average value of $\tau = 5\%$, as shown in Fig. 3 Col F. Viability with lower insolation and/or higher rates of cannibalization would require lower discount rates, higher market and/or social carbon prices and/or higher wholesale prices.

3.3 Accelerating investment - deviations from steady growth

The next test is whether it would be desirable to accelerate investment now or delay it. Consider the net benefit of a small increase in initial PV investment, dI_0 , leaving future investment at $I_0 e^{gt}$ unchanged. k_0 will be increased by dI_0 , and so will k_t , $t < L$, but by diminishing amounts as a result of degradation. k_t , $t > L$, will be unchanged. Future cumulative investment K_t will, however, be permanently raised by dI_0 and so $dK_t/dI_0 = 1$. The net benefit of this small increase can be found by differentiating (10):

$$\begin{aligned} \frac{dV_0}{dI_0} &= -\frac{dF_0}{dI_0} + \frac{dS_0}{dI_0}, \text{ where} & (11) \\ \frac{dF_0}{dI_0} &= f_0 + \int_0^T I_t \frac{df_t}{dI_0} e^{-rt} dt, \\ \frac{dS_0}{dI_0} &= \int_0^T [h_0 e^{-\zeta u} \frac{dk_t}{dI_0} \{(p_0 e^{-\pi t} - p_0) + \gamma_0 e^{it} - \Gamma_0 e^{It}\}] e^{-rt} dt \end{aligned}$$

These can be evaluated by noting that I_0 affects all future costs:

$$\begin{aligned} I_t \frac{df_t}{dI_0} &= I_t \frac{dc_t}{dI_0} = (c_0 - c_m) b \left(\frac{K_t}{K_0}\right)^{b-1} \frac{I_0 e^{gt}}{K_0} = gb(c_0 - c_m) e^{-g(1-b)t}, \text{ so} \\ \frac{dF_0}{dI_0} &= f_0 + gbc_0(1 - c_m/c_0) \psi(r - gb, T). \end{aligned} \quad (12)$$

In contrast k_t is only affected for L periods, and $dk_t/dI_0 = e^{-\delta u}$, so

$$\begin{aligned} \frac{dS_0}{dI_0} &= h_0 \int_0^L [(p_0 - p_0 e^{-\pi t}) + \gamma_0 e^{it} - \Gamma_0 e^{It}] e^{-(r+\zeta+\delta)t} dt, & (dS/dI_0) \\ \frac{dS_0}{dI_0} &= h_0 [p_0 \{\psi(r + \zeta + \delta, L) - \psi(r + \zeta + \delta + \pi, L)\} + \gamma_0 \psi(r + \zeta + \delta - i, L) - \Gamma_0 (r + \zeta + \delta - I, L)]. \end{aligned}$$

The effects of raising the current rate of investment are shown in the last line of fig. 3. Note that while Col I shows the trajectory to be socially unprofitable, raising the rate of current investment would improve social value, so there may be another initially higher trajectory with a positive social value. The implication is that accelerating the rate of investment in PV is globally socially justified in all these cases. More important, a global programme to fund continued investment in solar PV seems socially justified, particularly if it can be located in good resource locations, and evaluated using a sensible carbon price and public sector (low) discount rate.

4 Conclusions

The models demonstrate how to judge whether current and proposed future rates of investment in solar PV are justified, given assumptions about the future prices of fossil fuel and carbon displaced, as well as, critically, the learning rate and discount rate, the projected future growth path and insolation in the supporting countries. In the decentralized *Apollo Programme*, the average insolation will be lower but might change more slowly, and the viability of the *Programme* is more marginal, but even here raising the rate of investment looks attractive. The method here has been applied to constant growth cases as for such there are explicit formulae that allow a study of the impact of changing particular assumptions, but the approach can be readily extended to any projected PV trajectory, such as the second case in Fig 2, using the original formulae with time subscripts and spreadsheets to evaluate the annual values.

Given a more fully reasoned model of how learning disseminates and the role of induced (or planned) R&D, it might be possible to compute the optimal trajectory, which would almost certainly start with higher rates of investment, falling over time as the costs of subsidizing an ever larger investment rise while the future cost reductions decline. In this simplified model, the main conclusion is that accelerating the current rate of investment appears socially attractive under a wide range of assumptions.

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