UNIVERSITY OF CAMBRIDGE
Faculty of Economics

Cambridge Working Paper Economics

Cambridge Working Paper Economics: 1714

WHAT FUTURE(S) FOR LIBERALIZED ELECTRICITY MARKETS: EFFICIENT, EQUITABLE OR INNOVATIVE?

David Newbery

31 March 2017

Well-designed electricity liberalization has delivered efficiency gains, but political risks of decarbonizing the sector have undermined investment incentives in energy-only markets, while poorly designed regulated tariffs have increased the cost of accommodating renewables. The paper sets out principles from theory and public economics to guide market design, capacity remuneration, renewables support and regulatory tariff setting, illustrating their application in a hypothetical high capital cost low variable cost electricity system in "Andia" that resembles Peru. Such characteristics are likely to become more prevalent with increasing renewables penetration, where poor regulation is already threatening current utility business models. The appendix develops and applies a method for determining the subsidy justified by learning spillovers from solar PV.

What future(s) for liberalized electricity markets: efficient, equitable or innovative?

EPRG Working Paper 1705

Cambridge Working Paper in Economics 1714

David M Newbery

Abstract Well-designed electricity liberalization has delivered efficiency gains, but political risks of decarbonizing the sector have undermined investment incentives in energy-only markets, while poorly designed regulated tariffs have increased the cost of accommodating renewables. The paper sets out principles from theory and public economics to guide market design, capacity remuneration, renewables support and regulatory tariff setting, illustrating their application in a hypothetical high capital cost low variable cost electricity system in "Andia" that resembles Peru. Such characteristics are likely to become more prevalent with increasing renewables penetration, where poor regulation is already threatening current utility business models. The appendix develops and applies a method for determining the subsidy justified by learning spillovers from solar PV.

Keywords Electricity market design, tariffs, renewables support, utilities

JEL Classification D44, L51, L94, Q40, Q48, Q51

Contact dmgn@cam.ac.uk
Publication March 2017
Support The paper is the revised version of the Presidential address to the IAEE during the author's presidency of 2013

What future(s) for liberalized electricity markets: efficient, equitable or innovative?

David Newbery[1]
Energy Policy Research Group, University of Cambridge[2]

31 March 2017

1. INTRODUCTION

In 1990 Britain led Europe in unbundling, liberalizing and privatizing the electricity supply industry[3] and paved the way for the European Commission to enact a series (three and counting) of Directives to create liberalized and integrated energy markets across the European Union.[4] The advantages of competition, when combined with appropriate restructuring and incentive regulation, have been demonstrated[5] and underpin the European Union's commitment to a market approach to energy policy. However, the growing acceptance of the challenge of climate change, the need to decarbonize electricity rapidly and, as part of that goal supporting the massive deployment of renewables through the EU's *Renewables Directive* (2009/28/EC), has created major challenges to the traditional utility model. The most mature renewables, wind and solar PV, are intermittent and have low reliable capacity factors but high peak outputs. Subsidies to solar PV have disproportionately favoured sub-scale domestic household take-up, and in contrast to past conventional generation connected to transmission networks and dispatched by the System Operator, a significant fraction of renewables is connected to distribution networks (90% in the EU: EC, 2016) and not subject to dispatch. Distributed Energy Resources (DER), including both locally connected generation and demand side management, are increasing their penetration, displacing the traditional transmission managed operation of the network, and posing significant operational challenges to System Operators.

This paper considers some of the implications of these developments for the future of electric utilities – including generating, retailing and network companies – as

[1] Email dmgn@cam.ac.uk, +44 1223 335248, Faculty of Economics, Sidgwick Ave, Cambridge CB3 9DE, UK

[2] David Newbery is Director of the Energy Policy Research Group (EPRG) at Cambridge University. This paper has evolved considerably since early versions were presented in Daegu, Anchorage and Dusseldorf during my term as President in 2013, in New York in 2014 and at an FTI-CL workshop on *Towards the Target Model 2.0*. I have been much influenced by discussions with EPRG colleagues, stakeholders, Fabien Roques of EPRG's conference sponsors FTI-CL, and meetings in MIT and Madrid, in particular the contributions of Ignacio Pérez-Arriaga. I am indebted to R-J Lange, Matti Liski and Adonis Yatchew for comments and encouragement.

[3] Newbery (2000, 2005, 2006, 2012a, 2013)

[4] Bergman et al. (1999)

[5] Galal et al. (1994), Newbery and Pollitt (1997), Pollitt (2012) and references therein.

well as the implications for the regulation of networks, both transmission and distribution. Policy-makers are responsible for market design and interventions needed to meet various objectives, ideally informed by both good principles and evidence. They and regulators have a key role to play in balancing the often conflicting objectives of efficiency (ensuring that the prices and incentives deliver the least cost outcomes), equity (protecting less well-off consumers, ensuring that tariffs and charges are 'fair' and acceptable), and innovation, which may entail what appear inefficient and possibly inequitable tariffs to promote new developments. Net metering is an example of a tariff structure that is both inefficient and inequitable, but which proponents argue is necessary to kick-start the move to a more decentralized electricity supply industry that empowers (some) consumers and creates learning and, perhaps, valuable social acceptability. A better example is support for renewable electricity above the value of carbon displaced, which is costly, often financed in unfair and inefficient ways, but can be justified for the learning benefits created (as demonstrated in the Appendix and Newbery, 2017). In both cases there are better ways of delivering these innovations.

Two aspects of this more decentralized and decarbonized system are critical to the design of markets and regulation. Decarbonized generation is often characterized by high capital costs and low variable costs. Nuclear power, hydro-electricity, wind, both on- and off-shore, and solar power meet this description, although bio-energy and carbon capture and storage (CCS) have high variable costs. Second, rapid advances in Information and Communications Technologies (ICT) and the power of Moore's Law (that information processing costs halve every 18-24 months) mean that the costs of communicating with and controlling units (generation and demand) are falling to the point where Distribution Networks Operators (DNOs) can take similar control powers as Transmission System Operators (TSOs), graduating to become Distribution System Operators (DSOs). New energy service firms can similarly aggregate smaller unit offerings into Virtual Power Plants and offer their services to System Operators (DSO and TSO). This ICT revolution allows more active management of all networks, including those within buildings, and increasingly allows more granular pricing that better reflects the value or cost of power at each location and moment, ideally signaling least cost actions to those best placed to respond.

The next section identifies the relevant theories needed to understand and address these challenges, while the remainder of the paper illustrates their application.

2. RELEVANT THEORY

The underlying assumption supporting liberalization is that markets deliver more efficient outcomes than bureaucrats. The conditions for market efficiency are demanding – a full set of markets (current and future, including insurance markets[6]), no market power, no externalities and rational well-informed actors. The Electricity Supply Industry (ESI) is, unfortunately for this claim, characterized by missing markets, market power and externalities (Newbery, 2016a; 2005; 2012a). Nevertheless, complete market theory can be helpful in designing markets and policies to address market failures, as illustrated below.

The first principle is that externalities (greenhouse gas emissions, air pollutants, learning spill-overs) should be properly charged (via carbon taxes) or compensated (via suitable targeted subsidies). The EU Emissions Trading System is an attempt to confront major emitters with a price to be paid for CO_2 emissions, and while some jurisdictions have similar schemes for sulphur dioxide and nitrogen oxides, others address these through emissions standards. The whole issue of compensating those who produce learning externalities is considered at greater length below.

Transmission and distribution networks are natural monopolies that require regulation both to prevent consumer exploitation and investment protection, and as such efficient pricing will fail to cover their full cost. Their marginal operating costs are primarily losses, a tiny fraction of the total cost, and the larger part of efficient pricing is to address congestion through locational marginal pricing, (Schweppe et al., 1998). Even if that is employed (and Europe has yet to adopt it), and prices are on average equal to long-run marginal cost, there would still be a large shortfall to be recovered.

If, as is likely, policy makers choose more reliable systems than would be supported by competitive wholesale markets and decentralized investment decisions, efficient pricing will result in a shortfall in generation capital costs that also needs to be recovered. Most of the promising renewable technologies create external learning benefits, while R&D creates public (knowledge) goods, neither of which is recovered by competitive pricing. In all these cases, efficient prices will not cover the full system costs and the shortfall will have to be collected, balancing the objectives of efficiency and equity, concepts that are central to modern public economics (as set out in e.g. Atkinson and Stiglitz, 1980, 2015). Efficiency dictates minimizing deadweight losses; equity tempers this by considering who bears these costs. While familiar to public economists, these principles seem less familiar to energy economists and policy makers.

Transmission and distribution networks have an element of excludable public goods (sometimes called club goods) in that would-be beneficiaries can be excluded from access unless they pay the membership fee that covers the shortfall in revenue from efficient pricing. One of the oldest theories of the efficient supply of such public goods is the benefit principle, in that if agents could be persuaded to reveal the marginal value

---

[6] This requirement can be relaxed to rational expectations combined with risk-neutrality (Newbery and Stiglitz, 1981).

they attach to an increment of supply, the sum of these marginal values would indicate the total benefit from the increment, which should be delivered if this exceeds the marginal cost (Samuelson, 1954). For network expansion it suggests that the beneficiaries should pay – e.g. via deep connection charging for new generation that would pay the cost of reinforcing the network to accept the infeed.[7] In practice, it is often hard to identify all the beneficiaries, let alone determine their individual benefits, and some alternative way of collecting the revenue shortfall is required than voluntary contributions.

Given its high capital cost and need for revenue recovery, it is not surprising that some of the most innovative ways of recovering revenue shortfalls were developed in the electricity industry. Marcel Boiteux (1956),[8] when head of EdF, addressed the question of how a monopolist should set cost-recovering prices to minimize deadweight loss, a problem that Frank Ramsey (1927) had earlier addressed when designing indirect taxes. The Ramsey-Boiteux rule argues that the efficient taxes (or charges to make up the shortfall of revenue from pricing at marginal cost) should lead to equi-proportional reductions in all electricity service demands, thereby minimizing the total deadweight loss. In simple cases in which the price of one good does not affect the demand for the other goods supplied, the tax or mark-up should be proportional to the inverse elasticity of demand. Electricity markets offer a range of services with differing demand elasticities (for customers connected at different voltage levels, for connection relative to demand, for peak demand, and/or at different hours of the year) and charges that lead to equi-proportional reductions in all these demands suggests higher mark-ups on capacity rather than consumption.

The public economics principle for recovering revenue shortfalls is that the inevitable distortions needed to raise revenue above efficient pricing should fall on final consumers, and not distort production decisions (Diamond and Mirrlees, 1971). This is most relevant when recovering the costs of support for demonstration and deployment of renewables, which most countries levy on all electricity consumption without exempting producers. Germany exempts energy-intensive industries from their high green levies, which the Directorate-General for Competition, European Commission (DG COMP) argues, correctly, is discriminatory and hence not legal. The proper response is that all, not just energy-intensive, industries should be exempt, so there is no discrimination between industries. Again, there is a tension between "fairness" (all, particularly "wealthy" companies, should share the burden) and efficiency. In this case, consumers

---

[7] There is an extensive literature on decision criteria for transmission expansion, ranging from the California ISO approach (Awad et al,, n.d.) to those that emphasise mechanism design to delegate decisions (Hogan et al., 2011; Rosellón &Weigt, 2011).

[8] Boiteux (1949) had earlier addressed the classic problem of peak load pricing, central not just to electricity pricing but of far more general economic interest.

ultimately bear the costs imposed on firms in the prices they face when buying from the firms, and it makes matters worse to amplify firms' costs and hence raise prices with additional avoidable deadweight costs. Note also that industries should be charged for harmful externalities, e.g. via a carbon tax or emissions trading price, and there may be a second-best case for discriminating between industries that are exposed to international competition and those that are not in rebating carbon taxes (see e.g. Böhringer et al., 2016).

The deadweight cost of a tax increases as the *square* of the tax rate (Newbery, 1990), so doubling the tax base and halving the tax rate halves the total deadweight cost. The final relevant public economics principles are that deadweight losses are minimized by broadening the range of goods on which the revenue is collected, and that equity is better addressed through taxes related to ability to pay (e.g. income) than through differential taxes on specific goods. That argues for a uniform rate of Value Added Tax (VAT) applied to all goods and services that falls only on final consumers (Atkinson and Stiglitz, 1980; Deaton and Stern, 1986). Subsidies to correct the competitive electricity market's inability to finance external benefits should therefore be financed from general taxation, not by concentrating the levy on a single good (electricity) but by spreading it over all consumption or income, as all benefit from the externality benefits of future climate change mitigation. It also argues for imposing the standard rate of VAT on energy, rather than the lower rate adopted in some countries like the UK. Again, these principles run into political arguments of "fairness" (more properly expedience, where charges carry less emotive import than taxes, and raising taxes always attracts complaints, whereas leaving inefficient distortions in place rarely generates much reform pressure).

The practical question is whether it is reasonable to rely on governments setting sensible taxes to address distributive justice, or whether they are so constrained by perception and party politics that ameliorative redistributive action is delegated to regulatory bodies charged to take account of fuel poverty and the like. Legislation that charges regulators to take account of distributional impacts is the almost inevitable consequence of an unwillingness of governments to take adequate responsibility for distributional justice.

High capital costs make the cost of finance a major part of system costs. The amount and type of risk is a major determinant of the cost of capital, with the risk-free real rate of interest less than 2%, while the hurdle rate of return required to persuade developers to invest in some generation technologies over 10% real (DECC, 2013a). Principal-agent theory (e.g. Laffont and Tirole, 1993) balances the incentive effects of allocating decisions to those with the best information and best placed to manage the risks against the cost of bearing that risk. The cost of risk increases as the *square* of the deviation and its impact of the bearer's *total* consumption risk, and so depends on the extent to which it is correlated with other risks, and the number of agents over whom it can be spread. Sharing the risk equally between two identical agents halves the *total* cost of the risk.[9] That is an argument for spreading any market risks either over a large number of shareholders (particularly if the risk is uncorrelated with aggregate stock market risk, like wind output) or over final consumers, for each of whom the resulting increase in the variability in total consumption is small. Transferring all the risk to consumers for whom the cost is least may, however, reduce the agent's incentive to manage and reduce the risk efficiently.

The theory of the firm and its foundation in transaction cost economics (Coase, 1937; Williamson, 1981, 1985) constrains what business models are likely to be viable as services become increasingly decentralized and their values smaller. Business models not only need to deliver profits larger than these transaction costs, but are vulnerable if they exploit price differences that are a creature of either currently imperfect charging or inefficient tax-like methods of cost recovery. This is probably most obvious for the various direct and indirect supports for domestic solar PV, and perhaps less obvious in the case of electric vehicles, where high road fuel duties effectively subsidize untaxed electricity used in the electric vehicles. Road pricing that replaced fuel duties as a better way of charging for road use would remove that distortion and reduce the attraction of electric vehicles (Newbery and Strbac, 2016).

Networks differ from normal markets in which buyers and sellers interact directly, in that they can offer a platform for intermediaries to connect agents, each of which offers the other network benefits. Such two-sided markets have been greatly facilitated by the ICT revolution, and are exemplified by credit card companies (e.g. Visa, Mastercard), who offer attractive forms of payment to buyers thus making sellers who honour their cards more attractive to the buyers. A larger customer base for the platform provider confers more network benefits and creates economies of scale, often leading to intense competition and market concentration. The importance for firm behaviour is that the nature of the network benefits conditions the business models and pricing schemes that are viable. Weiller and Pollitt (2014) explore how the electricity supply industry (ESI)

---

[9] Adding a project with a random outcome X to underlying (random) income (or wealth), W, and expanding the resulting utility function $U(W+X)$ around its initial value in a second order Taylor expansion (normalizing $U' = 1$ to measure utility in money units but retaining risk aversion, i.e. $U''<0$) causes an increase the agent's income of $\Delta EU \approx EX(1 - R[\frac{1}{2}\sigma_x^2 (EX/EW) + \rho\, \sigma_w\sigma_x])$, where $R = -W\, U''/U'$, the dimensionless coefficient of relative risk aversion, ρ is the correlation coefficient of the risky project income with original income, σ_w is the coefficient of variation (CV) of income, and σ_x is the CV of the risky project. Highly correlated risk (high ρ) raises the cost, while uncorrelated risks can be diversified. If a project uncorrelated with income ($\rho = 0$) is divided among n identical agents, each receives a value $\Delta EU \approx E(X/n) - \frac{1}{2}(R/EW)\sigma_w^2(EX/n)^2$ and the total value is $n\Delta EU \approx E(X) - \frac{1}{2}(R/EW)\sigma_w^2(EX)^2/n$. The total cost of risk has therefore decreased by a factor n.

can be viewed as a platform-mediated, two-sided market and the consequences for business models for aggregating decentralized DER.

2.1 Special features of electricity

Although electricity might seem the archetype of a single homogenous product (all electrons look the same), the ESI delivers a range of different services including the delivery of energy (kWh), of capacity for reliably meeting demands (kW), as well as the quality of power at a particular location. Its wholesale value is therefore made up of the energy value (kWh), the value of reliability (i.e., the ability to meet demand) provided by capacity (kW), and quality of service (voltage stability, frequency, reactive power, etc.) which is provided by a range of ancillary services. The pricing of delivered electricity also represents a bundled service made up of the wholesale cost, transmission and distribution costs, as well as retailing, contracting with, and metering the customer.

Electricity is characterized by a range of particular demand and supply features which distinguish it from other products. The key physical challenge is that supply must equal demand at all nodes of the system in real time, which can be facilitated by storage to a limited extent (it is expensive, therefore of modest size, and does not automatically balance supply and demand without intervention). The demand for electricity shows substantial volatility on an hourly, daily and seasonal basis. At the same time, most demand is largely unresponsive to prices in the short run since most consumers do not see the cost of their electricity in anything close to real time, although intelligent active demand management may alter this. Even given smart meters, many customers may have a preference against having to respond quickly to rapidly varying prices. For related reasons, consumers’ true willingness to pay for electricity services is difficult to measure.

2.2 Efficient pricing of capacity-constrained production under uncertainty

Electricity generating units have well-defined capacities, but some probability of failure, so that to meet an acceptable standard of reliability, some reserve margin will be required. Different units have often very different variable costs, and the least cost dispatch ranks plant in order of increasing short-run marginal cost (SRMC), with that of the last plant dispatched setting the System Marginal Cost (SMC). The efficient price must also reflect scarcity (the value of the capacity in meeting the reliability standard) and any other costs directly involved in delivering power of the right quality to final consumers. If we ignore this last qualification, the efficient price is P = (1 – LoLP)*SMC + LoLP*VoLL, where LoLP is the instantaneous Loss of Load Probability and VoLL is the Value of Lost Load. The first term is the marginal cost of delivering power if there is no loss of load, and the second term is the value of the power if there is a loss of load, each multiplied by their event probability. The terms can be rearranged to give

$$P = \text{SMC} + \text{LoLP}^*(\text{VoLL-SMC}), \qquad (1)$$

where the first term is now just the short-run marginal cost of generating the power and the second term is a capacity payment to remunerate the capacity kept available to provide reliability.

If the system is in efficient long-run equilibrium with exactly the right combination of plant of differing costs to meet the time pattern of variable demand, and if there are constant returns at the scales at which the plants are chosen, then setting this efficient spot price will cover the costs of the entire generation fleet.[10] In practice, given the risk aversion of either the utility (if it is allowed to recover its "justified" costs) or the regulator/politician charged with ensuring reliability, whose necks are on the line if the lights go out but who can recover the costs from electricity consumers, there is a tendency to overcapacity, in which case this efficient price will not recover total costs. This has implications for the need for, and design of, capacity remuneration mechanisms discussed below.

[10] The efficient portfolio of plant is determined using screening curves as set out in e.g. Stoft (2002), who also establishes this standard result for the case of electricity wholesale markets.

2.3 Charging for ancillary services

Vertically integrated generation and transmission utilities supply a bundled product of energy, reliability and quality of service, and so do not need to explicitly pay their generating units for the ancillary services to deliver quality. With unbundling and ownership separation, some services are explicitly paid through the balancing market or mechanism, some, like black start, are contracted and paid, but others become obligations under the grid codes and connection agreements, often not explicitly rewarded. As the share of intermittent generation rises, and with it an increase in non-synchronous penetration,[11] so new flexibility services are needed to maintain quality and need to be remunerated if investment decisions are to be efficiently guided. Investors deciding on the type of generating plant to build need to balance the increased cost of greater flexibility against the revenues they may earn, and if markets or payments for these services are missing, then the cost of maintaining quality with the wrong portfolio of generating assets will be higher (CEER, 2016; Newbery, 2016a). As some of these flexibility services can be provided by modern HVDC interconnectors, it becomes important that they are also compensated and allowed to offer these services (which may be at the expense of selling their entire capacity ahead of time to wheel power).

2.4 Capacity remuneration mechanisms

The case for a capacity auction has been cogently argued,[12] not least in the discussion papers[13] that set out the reasons for the British Electricity Market Reform delivered in the *Energy Act, 2013* (HMG, 2013). The case rests on two main arguments. The first is the standard one that prices are not allowed to rise to the value of lost load,[14] so there is a missing money problem. That can be addressed by contracts, specifically Reliability Options. The second problem is that of missing markets – for various flexibility services (again, remediable) but more fundamental is the lack of adequately distant futures and risk markets for investors to hedge risk. That might not matter if investors were confident that they faced only the normal commercial risks that large

[11] Conventional rotating generation turbines are synchronised to the grid frequency and have substantial inertia, so that if there is a momentary loss of supply, that inertia prevents the frequency falling too fast. Wind power has effectively no inertia, which has to be provided in some form to maintain frequency within acceptable limits.
[12] See e.g. Newbery and Grubb (2015) and the extensive references therein, including the *EEEP* Symposium on 'Capacity Markets' (Joskow, 2013).
[13] e.g. DECC (2010).
[14] The day-ahead European auction has a price cap of €3,000/MWh, well below the VoLL, and a price that has already been reached in some markets. The System Operator in GB supplies emergency services at £6,000/MWh, while the GB VoLL is £17,000/MWh.

well-capitalized electricity utilities are willing to accept (although at a suitably high hurdle discount rate), but energy policy has become increasingly politicized. It is difficult to predict future climate change and renewables policy, to mention just two kinds of policy that impact utility profitability. The lack of future risk markets makes investment in peaking plant that may run a small but highly variable number of hours at hard to predict prices (that are in any case capped) unduly risky and hence unnecessarily costly.

2.5 Setting regulated tariffs

Transmission and distribution (T&D) accounts for a large share of investment needed, globally amounting to 43% of total electricity investment from 2012-35 (IEA, 2012). The forecast share of distribution in total investment is 32%, nearly three times the share of transmission. The demands for T&D investment increase with the share of Renewable Electricity Supply (RES), as fossil generation can typically be located closer to final demand, economizing on the additional T&D requirements. As natural monopolies, T&D tariffs are set by regulators and ought to be cost-reflective. What is striking looking across Europe is the considerable variety in network costs and, less surprisingly, taxes and levies to recover renewables and other activities, shown in Figure 1 for domestic consumers. A similar range can be found for industrial consumers at comparable voltages and volumes (MWh/yr).

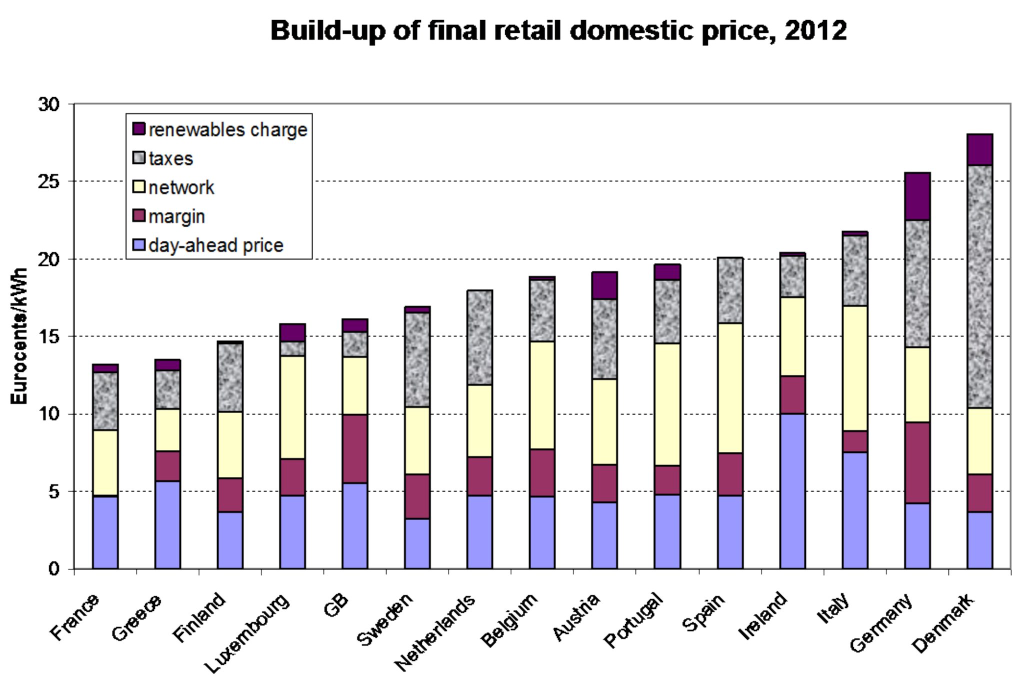

Figure 1 Build-up of final domestic electricity prices in selected EU countries, 2012
Source: DECC (2013b) and ACER (2013)

Tariffs need to be set to encourage efficient investment in and use of the networks, but also to recover any shortfalls in revenue remaining after setting tariffs at their efficient levels. Efficient pricing means setting the prices at each node on the network at the locational marginal price, LMP (Schweppe et al., 1998), as in many transmission areas in the U.S. Even if transmission and distribution systems are efficiently sized and priced, they are unlikely to cover more than a quarter of total costs (Pérez Arriaga, et al., 1995; Rubio-Oderiz et al., 2000). As LMPs are not (yet) used in Europe, at best marginal transmission losses would be covered. Almost all the remaining costs are fixed and in need of recovery. As a result, network utilities have to set prices above the efficient (LMP) level at least some of the time to recover fixed costs.

The solution practiced by many utilities, exemplified by EdF under Boiteux, was "cost-reflective" pricing,[15] to charge for transmission at peak hours (on the argument that the transmission system was sized to deliver the peak demand). In Britain, National Grid charges Distribution Networks Operators (DNOs) on their demands on the transmission system in Triad half-hours – the three half-hours separated by at least 10 days of system maximum demand. While peak demands might drive transmission expansion, economies of scale imply that efficient peak pricing will still lead to revenue shortfalls that should be targeted to reduce *all* demands equi-proportionally. Just charging for the peak demand in three half-hours will likely lead to inefficiencies.

High peak demand charges at the grid supply point to the DNO (which are then passed on to the meters of larger customers) encourage both DNOs and these customers to embed generation behind the metering points and claim an embedded benefit (for reducing the peak charges). This problem became particularly acute in Britain as the cost-recovery element in transmission charges rose from modest levels (£10/kWyr) to high levels (£60/kWyr) with the massive investment in off-shore links to wind-farms and to strengthen connections to Scotland to evacuate on-shore wind. This, when combined with capacity payments (discussed below) has over-encouraged inefficiently-sized distributed generation behind the meter. The excess cost of inefficient T&D tariffs has thus recently become very high (Newbery, 2016b; Ofgem, 2017).

The principles set out above argue that the shortfall in T&D should be collected from final consumers, not net of any generation, as producers (i.e. all generators, not just embedded generators and regardless of the voltage level at which they are connected)

[15] There is some ambiguity about the meaning of "cost-reflective", which might include charges that are proportional to marginal costs, or even the average cost of expansion. The Australian Energy Market Commission has recently published a clarification of their principles of what the required cost-reflective tariffs mean, and specifically that "Each network tariff must be *based on* the long-run marginal cost of providing the service." (Emphasis added, see http://www.utilitymagazine.com.au/cost-reflective-pricing-giving-consumers-the-power-of-choice/). This would seem to allow mark-ups on the marginal cost.

should face efficient prices to guide their choice (of location, size, type, etc.). The challenge of finding efficient prices on local networks where their specific topology can lead to large differences across small geographic areas should not be underestimated (MIT, 2016).

The cost-recovery element levied on gross consumption should reduce demands by an equal proportion (which will require higher proportional mark-ups for the less elastic demands such as for the size of connection or fuse). British DNOs set higher tariffs in the afternoon peak hours in the winter period for domestic consumers as arguably those hours have the most inelastic demand. If revenue shortfalls are recovered by additional energy charges, net metering of e.g. solar PV is distorting, and excessively encourages sub-scale renewables, as well as being highly inequitable if the PV subsidies are paid for by the consumers without PV (typically less well-off).

Network connections offer the option of taking power when any local sources are not contributing and as such should be paid for. If customers can specify the maximum amount they would like to be able to take at any moment and if this can be measured (and excesses charged at a suitable penal rate), then this would be a candidate for cost-recovering charges. Similarly, the principle of deep connection charging that applies to large distribution-connected generation in GB could also be applied to new loads (e.g. computer server farms) seeking connection, encouraging efficient location and reducing the shortfall in network expansion costs to be recovered. Improved network modeling, the move from DNO to DSO, better metering and ICT makes more granular and more efficient pricing increasingly practical.

3. SUPPORTING RENEWABLES

The European Commission, among other agencies, has pressed for renewables targets (which require subsidies for their support), primarily to reduce greenhouse gas emissions but also to promote growth, employment, innovation and the renewables industries.[16] The numerous documents setting out the principles for support are mostly silent on the reasons why supporting renewables, rather than just reducing greenhouse gas emissions, should be singled out, and most of the reasons, other than mitigating climate change, are dubious at best. This matters, as until the objectives of a policy are clearly stated and defended, it is hard to judge whether the policies chosen to support them are efficient, justified and proportional.

The main case for supporting different renewable energy technologies is that their deployment drives down costs through learning by doing and induced technical progress. If technology developers can see a viable market for their products, they will

[16] See e.g. http://europa.eu/rapid/press-release_MEMO-16-3987_en.htm

be encouraged to research, develop, test, and, if the results are promising, scale up production to 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 rates[17] and even their attribution to deployment or R&D (Jamasb, 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% learning rate for PV modules for an installed base of 227 GW_p.[18] 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%. Gas turbines have a one-factor rate of 14%, but the two-factor learning rate is much lower at 1.4%, and the installed base is so large that to double it would require truly massive investment. In contrast, 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%/yr.

3.1 Assessing the social profitability of supporting solar PV

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. As an illustration of assessing whether it is worth supporting solar PV (which until recently appeared very expensive), the Appendix sets out a simplified social cost-benefit analysis, asking the question, starting from 2015,[19] does it make sense to continue to subsidize PV to accelerate the date at which it is cheaper than fossil fuel alternatives? (Newbery, 2017 provides a fuller exposition.)

The evidence reviewed in the Appendix suggests that even although PV has only recently become cost-competitive in favourable locations (sunny summer-peaking systems with high air-conditioning loads), if the learning rates are both attributable to increasing cumulative production and likely to continue at comparable rates in the future, then the global case for supporting that expansion seems reasonably solid, but

[17] Which 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.
[18] Subscript $_p$ 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.
[19] NREL (2016) gives recent cost and performance data.

unless a region (like China, or the EU) captures a sufficiently large share of the benefits or has a particularly favourable resource (sun) the selfishly regional benefits may not be sufficient to justify the subsidy cost. What is also clear is that it is much cheaper to provide this support in sunny locations, but also very difficult for the subsidies to be globally mobilized and then channeled to the best places. An additional problem is that local saturation requires complementary investment in flexibility services and stronger interconnections, both of which raise many of the concerns addressed in this article.

3.2 Designing renewables support schemes

The main case for supporting renewables is to reap the learning benefits that 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. Figure 2 illustrates the apparent persistence of Swanson's "Law" - that modules decrease in price by 20% for every doubling of cumulative shipped modules (shown as the straight line). The other line (with square markers) shows world-wide module shipments vs. average module price, from 1976 (\$104/W_p) to 2015 (\$0.58/W_p) in 2015 dollars. The actual decrease suggests a learning rate slightly greater than 20%,[20] a view supported by Fraunhofer (2016).

[20] Fig. 2 graphs data from ITRPV (2015) and can be updated from ITRPV (2016, fig. 46).

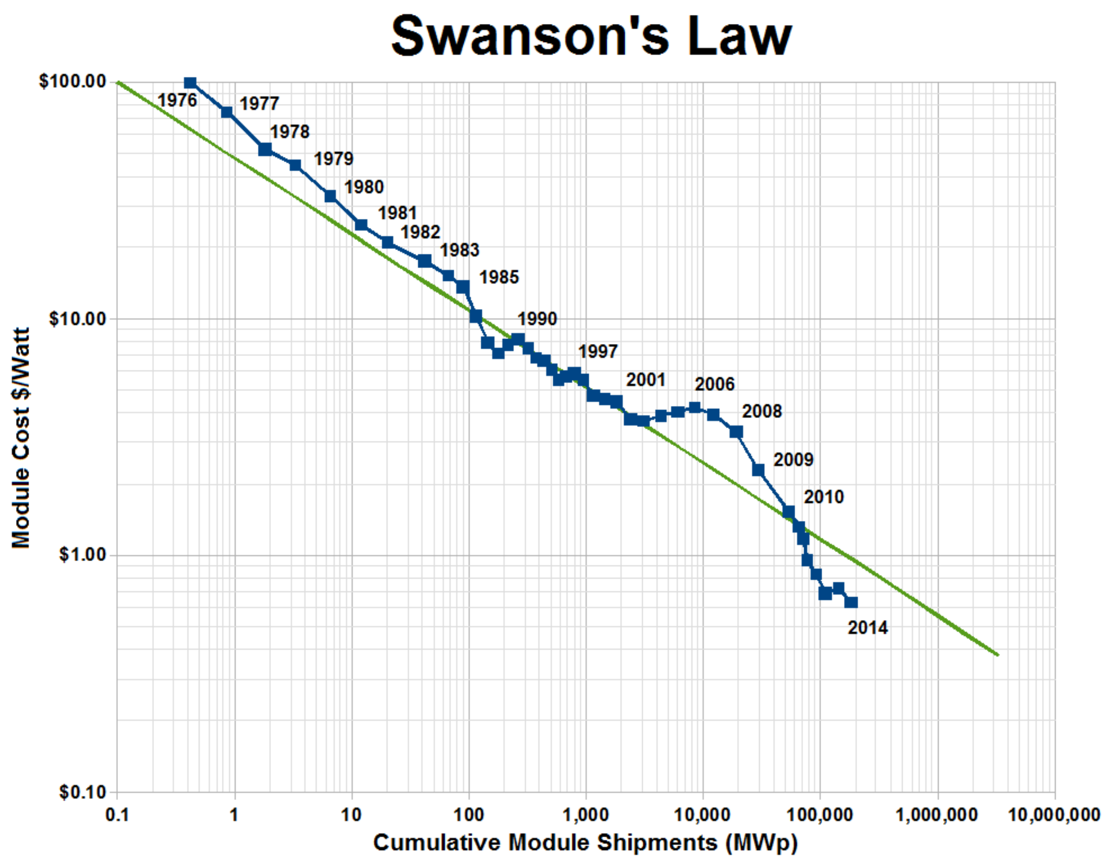

Figure 2 Cost reductions and capacity expansion in solar PV modules
Source: Delphi234 - Own work, CC0,
https://commons.wikimedia.org/w/index.php?curid=33955173

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),[21] 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.

The two arguments lead to quite different support mechanisms. The second would effectively be a carbon credit per MWh, for administrative simplicity probably based on a suitably RES output-weighted estimate of the carbon intensity of generation averaged over a year.[22] To take an example if the marginal carbon intensity is 0.9 tonne CO_2/MWh

[21] The CPS raises the cost of CO_2 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 tCO_2 for 2016/17 (HoC, 2016).
[22] http://www.ukenergywatch.org/Electricity/Realtime gives the instantaneous RES and total generation output and generation carbon intensity in real time for the UK. More accurately, one

and the shortfall in carbon price is \$20/tonne CO_2, zero intensity plant would receive a payment of \$18/MWh.

The first, and specifically renewables case for support, suggests that the market failure to be addressed is the unremunerated spill-over from investments that leads to learning and cost reductions. The implication, consistent with the EC *Clean Energy ("Winter") Package*,[23] is to target support on the investment rather than its output, and then allow the installation to sell electricity in the market like any other generator (with the addition of the carbon price correction mentioned above). The most elegant way to do this is to hold an auction for the support needed for the full capacity hours specified, e.g. for on-shore wind, China offers support for 30,000 hours (Steinhilber, 2016), i.e. for 30,000 MWh/MW installed capacity, which in good locations would be reached in 11-13 years.

The advantage of this is that for the developer the revenue stream of this support is highly predictable and hence can be used as collateral for debt finance, the cheapest form and hence lowering the cost of RES generation. An auction determines the least cost way of meeting the auction target (which can be specified in terms of MW capacity, or for a budget). The form of support does not over-reward favoured resource areas (of high wind or sun), as the aim is to support the delivery of capacity, not energy.[24] This in turn means that the primary determinant of location is the local wholesale price and the network costs, which, as 90% of EU renewables are connected to distribution systems (EC, 2016), are the DNO tariffs and connection charges. With nodal (LMP) pricing, as more developers locate in a favoured location, the local wholesale price will decrease and discourage further renewables at that location, and hence mitigate excessive network reinforcement costs. Even without nodal pricing, if, as in some countries (e.g. on distribution networks in GB) there are deep connection charges or use-of-system charges that reflect underlying LMPs, this will again encourage efficient least-system cost connections.

Newbery (2016b) provides an example to demonstrate the distortionary effects of subsidizing output rather than capacity. Suppose distant wind runs 2,500 hrs/yr and closer wind only 2,000 hrs/yr with an average wholesale price of \$40/MWh and an additional

---

would like an estimate of the *marginal* carbon intensity – the amount of CO_2 displaced by the extra RES set by the marginal plant in each time period. Depending on the relative prices of gas or coal that could be either a CCGT at the margin (0.367 tCO_2/MWh) or, more probably, coal at 0.973 tCO_2/MWh (averages for the UK, 2016).

[23] At http://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition, which has links to various proposed directives and regulations.

[24] Compare two sites, one which produces 2,000 full wind hours per year, the other 2,500 hours. If the discount rate is 5% real, and each is given the same price per MWh for 15 years, the windier site is given 25% more than the less windy site, but if each is given 30,000 full hours then the windier site is only given 6.7% more.

RES support of \$40/MWh (either by a green certificate valued at \$40/MWh or a Feed-in Tariff of \$80/MWh). The extra transmission use-of-system cost is, however, \$25/kWyr for the distant location compared to the closer one. The extra *value* of the distant wind is \$40/MWh x 500hrs = \$20,000/MWyr, \$20/kWyr, but after deducting the additional transmission cost, its extra value is negative, making the closer wind more valuable from a systems viewpoint. The additional *financial* attractiveness of distant wind (at \$80/MWh x 500hrs) is \$40/kWyr, which is higher than the extra \$25/kWyr transmission charge and so the windier site will be inefficiently chosen. The earlier EC *Renewables Directive* (2009/28/EC) specified the 2020 renewables target as a share of total energy, which encourages supporting energy rather than capacity, and to that extent was poorly designed. A preferable solution that would also address the concern of the EC 2017 *Clean Energy Package* to promote the efficient location of RES across the EU, would be to specify the RES support obligation in terms of a share of GDP.

The next section illustrates how these principles can be applied in an example.

4. ILLUSTRATIONS FROM "ANDIA"

Andia, a fictitious country with a strong resemblance to Peru, is an example intended to bring out features of a system with high capital and very low variable costs, and as such indicative of a future facing an increasing number of utilities. The questions to be addressed are how wholesale, T&D and retail prices should be set, and what the economics of renewable energy are.

Andia is a small isolated system with a large amount of run-of-river hydro and about 3 GW of storage hydro (in a 7 GW peaking system) that has less than four months' storage capacity. Recently discovered associated gas allows nearly half electricity demand to be met from gas, with the rest from hydro. The hydrocarbon field, which is far from demand centres and the sea, produces gas as a by-product of the liquids extracted. In order to realize its value the field is connected by pipeline to a liquefaction plant to export LNG and then along the coast to demand centres and gas-fired power stations.[25]

The LNG plant (the only export facility in Latin America) is running at full capacity, so the only alternative use of the gas, other than in power generation, is to reinject it for later use, either when there is spare capacity in exporting or adequate domestic demand. Its opportunity cost is therefore low – effectively the present value of its future use, which, if the export constraint cannot be relaxed, might be more than a decade hence.[26] If its export netback value into the LNG facility were \$US 1.9/mmBTU,

[25] See Honoré (2016) for maps and other information on Peruvian gas.
[26] Peru has some non-associated gas which can therefore set a higher commodity price, and the average gas price paid by thermal facilities in 2014 had risen to \$US 3.2/mmBTU. Since then gas prices have declined considerably (Honoré, 2016, fig 52) and seem set to remain low.

and exports could only be expanded with a delay of five years, its value today discounting at 10% real would be only \$4/MWh$_{th}$,[27] which would give a fuel cost of \$11/MWh$_e$ in an Open Cycle Gas Turbine (OCGT) or \$8/MWh$_e$ in a CCGT.[28]

Other variable costs might add \$4-5/MWh$_e$, to which should be added the cost of climate change damage as a carbon price. The US EPA (2016) estimated the social cost of carbon (which depends on the rate of discount) in 2015 at \$(2016) 42/tonne CO_2, with a range from \$13-\$65/tonne. That may be on the high side for an internationally agreed acceptable price, but in making investment decisions it is the future average value that matters, for which \$25/tonne may be a defensible figure under a Climate Change Agreement. This would add \$14/MWh$_e$ for an OCGT and \$9/MWh$_e$ for an efficient CCGT. Collecting these various cost elements, the variable costs of an OCGT might be \$30/MWh$_e$ and \$22//MWh$_e$ for an efficient CCGT.[29] These can be contrasted with the variable costs of operating on diesel of \$240/MWh$_e$ (including \$20/MWh$_e$ for CO_2), or 8-10 times that of gas. Of course, the fixed costs of the gas infrastructure (any processing plant to recover the associated gas and the costly pipeline) still need to be recovered as a capacity charge (sometimes concealed in a take-or-pay contract which effectively makes almost all the costs fixed). That will be included in the capacity charge estimated below.

If we look ahead to a time when the plant mix is in long-run equilibrium, using screening curves to select the least cost method of meeting any level of demand, we find that the optimal plant mix is very sensitive to fuel, carbon, O&M and fixed costs of the various plant types and sizes. Taking data from BEIS (2016),[30] diesel plant might be cheapest for the most expensive 25 hours per year, OCGT for 1,100 hrs, while CCGT runs on baseload until partially displaced (but still price-setting) by run-of-river hydropower (except in those hours when run-of-rive output exceeds demand, in which hours energy prices would fall to zero – a possibility ignored here). The diesel generator (and all other generators) would need to be paid its fixed cost of \$75/kWyr to enter the market (the cost of new entry), but then the system marginal cost, SMC, would cover the

[27] The medium-run price of LNG from the west coast of Latin America seems likely to be set by the cost of US shale gas, as contracts are typically indexed to Henry Hub prices. US shale gas apparently has a very flat supply curve and large reserves.

[28] Subscript $_{th}$ for the thermal content of the gas and subscript $_e$ per MWh of electricity produced. Netback based on a landed price in destinations of \$6.30/mmBTU (higher than current, e.g. exporting to Chile), and LNG shipping costs of \$1.4/mmBTU + 6% loss, LNG plant costs of \$1000/tonnes/yr capacity, 10% loss, \$30/tonne O&M, regas costs of \$0.30/mmBTU.

[29] Without a carbon charge, more OCGT would be installed and less CCGT, the OCGT would run more hours setting the energy price at \$16/MWh and the CCGT would be only slightly cheaper at \$13/MWh, so carbon pricing has (as intended) significant impacts on investment and carbon intensity in the long run.

[30] Taking the high cost 2018 costs for a 1,500 MW type F CCHT and a 400 MW OCGT, and their associated fixed and variable costs, from BEIS (2016, Table 19), assuming 10% cost of capital, 15 yr life for diesel and 25 yrs for gas turbines.

excess fixed costs of the more efficient plant by the construction of the screening curves. If the value of lost load (VoLL) is \$3/kWh,[31] then the implied Loss of Load Expectation (LoLE) is \$75/\$3 = 25 hours per year on average.

Suppose that Andia faces El Niño/La Niña rainfall conditions with low rainfall and inadequate hydro power once every four years and abundant rain also once every four years. Figure 3 shows the annual rainfall and hydro capacity factor over a long period for Peru. Interestingly the capacity factor has been rising, which might suggest that seasonality is becoming less significant, perhaps as dam capacity increases. Given our simplifying assumptions for the hypothetical Andia, the expected LoLE in rainy years might then be zero, 25 hrs in normal years and 50 hrs in dry years, with corresponding average annual *energy* prices of \$23.6/MWh, \$30.1/MWh and \$40.6/MWh. These energy prices will need to be uplifted by capacity payments as in equation (1) to give the wholesale price.

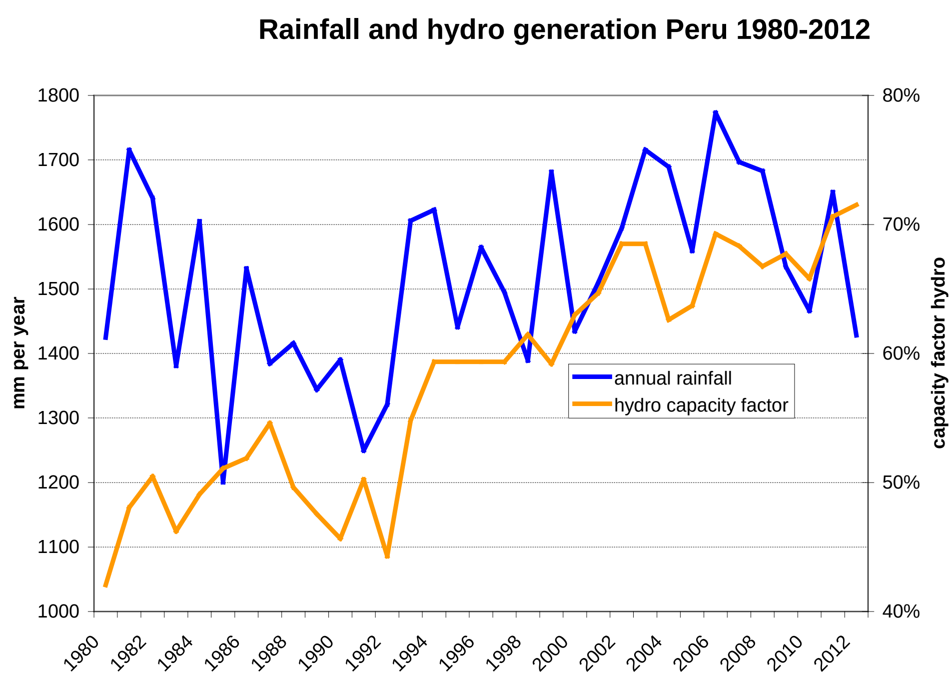

Figure 3 Rainfall and hydro-electric generation in Peru, 1980-2012
Source: http://sdwebx.worldbank.org/climateportal

The efficient wholesale price in this system is thus likely to be fairly low most of the time (\$22/MWh) but high (\$240/MWh) or very high (\$3,000/MWh) in scarcity hours. The spot price in periods of controlled disconnections would rise to the VoLL, \$3,000/MWh, but consumers would want contractual insurance against such high prices.

31 Scaling in proportion to GDP/hd. Peru has \$(PPP) 12,500/hd and Ireland \$(PPP) 65,000/hd. Ireland has a VoLL of \$16/kWh.

That is most sensibly provided by Reliability Options (ROs) priced at something above the likely variable cost of the most expensive supply (diesel), or perhaps $300/MWh (Vázquez et al, 2002). The System Operator (or other designated body) would then determine the amount of capacity needed to meet the reliability standard and then auction the ROs. The RO contract would pay the successful generator the auction clearing price, in return for the generator paying back the spot price less the RO strike price (e.g. $300/MWh) if generating, and the spot price if not, providing powerful incentives for availability in stress hours.

Thus in 25 hours per year a fully reliable diesel generator would only earn $60/MWh instead of the required $3,000/MWh needed to cover its full costs, so the shortfall in fixed costs would be $2.94/kWh x 25 hrs = $73.5/kWyr. This would be the net cost of new entry (assuming no other revenue from ancillary services). It would set the RO auction clearing price and that would be the amount of money to recover from consumers as part of wholesale electricity costs. If this is simply added to the SMC the annual *average* electricity costs would increase by $8.4/MWh to $38.3/MWh, but on scarcity grounds, the capacity charge would be doubled in dry years and zero in wet years, encouraging demand side response when most needed in the dry years. As a fixed cost the aim is to set charges to reduce demands for all services, capacity and energy, by the same proportion. The *ex-ante* chosen maximum demand (the amount covered by the RO contract) might be the least elastic demand and hence the target for most of the cost recovery. Clearly it cannot all be recovered in stress hours as the intent of the contract is to reduce price spikes. As a rough estimate, suppose the fixed costs were spread over the top quarter of demand hours, then the average wholesale price in those hours would be $89.90/MWh, with the remaining hours only $22/MWh.

There are several assumptions that could be relaxed. Hydropower is very capital intensive but conceivably less so than the cost of pipelines and/or transmission lines to reach some areas, but in the well interconnected parts of the country that can be accessed from existing gas pipelines, gas-fired generation is likely to be cheaper than additional hydro. In other parts of the country weak and costly transmission links may make other generation technologies cheaper (and by implication, more expensive than the estimates above).

The estimates above assumed no ancillary service profits, which would reduce the fixed costs as it would be paid directly by users. Storage hydro, however, is likely to be able to offer most of these at very low additional cost. Storage in dams would be preferentially retained for use at daily peak hours and thus allow prices to be stabilized over the day and perhaps week, but not for the whole year given the equilibrium choice of total capacity, giving rise to periods of controlled disconnection and high prices (where some water may be retained for an even worse future moment). Transmission constraints are likely to fragment the market and lead to higher local prices in some hours.

4.1 The case for renewable electricity

We can now return to one of the original questions and investigate the price that wind or other renewables might face and hence their economics. The case for subsidizing renewables in wealthy countries is that it will stimulate cost reductions, some part of which can be internalized within the club agreeing the support (e.g. the EU via the Renewables Directive), as well as correcting for the underpricing of CO_2. A small poor country can hardly be expected to provide subsidies for either reason, assuming, as here, that carbon is properly priced, although as argued above and in the Appendix, there is a powerful case for the club (ideally global, as envisaged by the *Apollo Programme*) financing PV deployment in high insolation areas such as Peru, where the required subsidy is likely to be lower. In short, the renewables in Andia should be eligible for support by, and count towards the renewables share of, the club of countries supporting renewables via the *Apollo Programme*.

The average SMC over a run of years is just $30.7/MWh. Fortunately with storage hydro wind and PV can offer its capacity factor (perhaps 25+% in both cases)[32] and thus receive that fraction of the capacity payment (here $66/kWyr). In the US PV power purchase agreements have been signed for 20 years at less than US$ 40/MWh (indexed, without "meaningful tax state credits", EPRI, 2016, fn 6), so with favourable (international concessional loans) PV would seem to be competitive against the relevant grid-connected average wholesale value of $47.2/MWh. Off-grid could be more attractive if it displaced diesel or has access to local storage hydro.

4.2 Recovering fixed network costs

Developing countries such as Andia will likely be incurring high costs rolling out networks to increase domestic electricity penetration. Setting network tariffs faces a direct trade-off between equity and efficiency, as the oldest and therefore more amortized networks will be in urban centres, while smaller villages will have newer and, per capita, more costly networks. The benefit principle of network finance might suggest that the incremental cost of transmission to new demands should be paid for by those demands while new generation would pay the deep connection costs (the increased network costs of evacuating the power), encouraging efficient location. These deep connection charges would be amortized over a period as a mortgage, with the property rights held by the generator, available to transfer to others wishing the same entry capacity. Such property rights give efficient entry and exit signals, in contrast to annual charges that can be

[32] Insolation in parts of Peru appears as good as the best locations in the southern US, where the CF for tracking grid-scale systems can be above 25% (see Appendix and Bolinger et al. 2016). Insolation data is available at http://solarelectricityhandbook.com/solar-irradiance.html.

avoided by exit. As the long-run marginal cost of network expansion is likely well below the average cost, the shortfall can be collected according to the public finance principles set out above.

The simplest and "fairest" approach would be uniform cost recovery of this shortfall across the country via uniform (spatial, not temporal) network tariffs on final consumption added on to nodal prices. One could go further in collecting proportionally more from urban areas that are richer and probably enjoy higher reliability than rural areas, on the benefit principle of charging that the rich are willing to pay a higher price for access to power than the poor. In short, the one principle that is hard to justify is to set end-user tariffs in proportion to the *average* cost of connecting them, although a proper social cost benefit analysis of expanding the network will clearly have to take account of all costs and benefits.

As almost all network costs are fixed, Ramsey-Boiteux charging would lead to equi-proportional reductions in *all* demands (hourly and capacity) passed through to final, not net, consumption. That would mean in periods and locations where the network is unconstrained, the retail energy price would be the wholesale price uplifted by marginal transmission losses in transmission and distribution. Average losses might be 10%,[33] raising the *average* delivered cost of power (energy + capacity) to $42/MWh. However, marginal losses are twice average losses so the average marginal loss will be 20%. Losses are proportional to the *square* of the power taken, so losses will be four times as high if power taken doubles. If peak power is twice the minimum, then *marginal* peak losses will be 32% and the minimum only 8%.[34] Spatial losses (at lower voltages, farther from transformers) amplify these further.

4.3 Illustration of setting retail tariffs[35]

To give some sense of the implications of these principles, suppose low voltage customers take one-third the power and twice the average loss and the remainder face half the average loss, then the average LV loss will be 20%, the marginal loss will be 64% at the peak and 16% off-peak, considerably raising the delivered energy price in higher demand hours (in this case to 164% of $89.90 = $147.4/MWh), of which half the

[33] T&D losses in Peru in 2011 were 6.4% of consumption from http://www.tradingeconomics.com/peru/electric-power-transmission-and-distribution-losses-kwh-wb-data.html but Wikipedia cites 4.7% T losses and 6.3% D losses in 2006, according to Ministerio de Energía y Minas 2007,

[34] MIT (2016) cites evidence from Australia (Ausgrid, 2011) indicating peak load marginal loss factors of 33-43%, so these rough calculations appear plausible

[35] The actual setting of retail tariffs in Lima appears quite cost reflective, and this section shows how to gain a rough sense of the relative sizes of fixed charges, peak and off-peak tariffs for a hypothetical set of assumptions, which are not too far from the average retail prices.

marginal loss (32% of $89.90 = $28.8/MWh) is a contribution to fixed costs, the balance of which still needs to be recovered.

In a mature system such as the US, T&D costs are one third total electricity costs,[36] but given the low average wholesale price in Andia, and an expanding system, T&D costs are more likely to be as high as generation costs (in this case $40/MWh averaged over the whole year),[37] and of these, transmission is likely to be roughly one quarter ($10/MWh = $45/kWyr at a 52% capacity factor), the rest ($135/kWyr) distribution costs.[38] Again if LV customers take one third the demand[39] but at twice the distribution cost ($270/kWyr) while others take the remainder at half the cost ($68/kWyr) the total to be recovered (T&D) for LV customers is $315/kWyr. Of this, the contribution of the difference in the marginal and average loss factor is $28.8/MWh = $130/kWyr, reducing the amount to recover in LV charges for T&D is $186/kWyr.

If these costs are collected half as fixed charges, half spread over the top quarter of hours, the LV fixed charge would be $93/kWyr and as the average demand is 0.14kW even if the average peak consumption is twice the average it would only be 0.28kW or a charge of $52/yr. The peak hour price would be $147/MWh + ($93/kWyr/1,125hrs = $83/MWh) = $230/MWh or 23¢/kWh. The price outside these top demand hours would be 8% higher than the wholesale price ($22/MWh) or 2.4¢/kWh. If LV customers have the same demand patterns as the total, the average energy price would be 7.6¢/kWh, and for a household taking 1,250kWh/yr the energy cost would be $95/yr and the fixed charge $93/yr, giving an average electricity bill of 18.8US¢/kWh. It would be quite justified to lower the fixed or even the energy element of the T&D charges on some classes of customer, recovering the balance from other richer customers or those more willing to pay for the public good element of a high penetration network, or by offering higher unit prices up to some threshold at which the fixed element is covered.

[36] https://www.eia.gov/Energyexplained/index.cfm?page=electricity_factors_affecting_prices

[37] T&D costs in Peru for retail customers in Lima are $52/MWh, and generation (energy and capacity and ancillary services) allocated to Lima retail are $81/MWh. Subsidies of $12.3/MWh charged to consumers bring the retail price up to $145/MWh or US¢14.5/kWh (correspondence with Miguel Juan Revolo Acevedo). T&D costs for retail customers will be higher than the average for all customers, although Lima may have a lower T&D cost per customer.

[38] For Lima, excluding RES support charges, generation and ancillary services accounts for about 60% of the total retail bill, but in other parts of the country T&D costs are likely to be a larger proportion of the total.

[39] The domestic share in Peru is closer to one quarter, with 91% penetration and 6.3 million households connected.

4.4 Assessment of final tariffs

The most striking conclusions to draw from this back-of-the envelope exercise is that fixed charges could make up half the final LV retail customer bill, and that the peak price could be nearly ten times the off-peak price. That might lead to a larger percentage fall in demand then than in the off-peak hours, suggesting some reallocation between peak and off-peak, or three categories, such as super-peak (high energy prices and high marginal losses), normal hours, and off-peak (e.g. 10pm-6am) but these are the fine details that careful network modeling can reveal, e.g. as exemplified in MIT (2016).

5. CONCLUSIONS

Efficient pricing requires setting prices at short-run marginal cost, which, in long-run equilibrium, will on average be equal to long-run marginal costs. As intermittent renewable generation increases its share, the ESI is increasingly characterized by high fixed costs and low, often very low variable costs but subject to capacity constraints that require values from the demand side to determine efficient market-clearing prices. These efficient prices can vary dramatically over time and space, and are typically below average costs, creating a potential revenue short-fall. Smart metering, dramatic reductions in the cost of ICT and the reform of outdated regulatory models should increasingly allow these more granular efficient prices to be passed through to distributed energy resources, which may be aggregated into virtual power plants to supply flexibility services to TSOs and, in future, emerging DSOs.

The viability of generation, network and retailing companies will increasingly depend on how and whether they are allowed to efficiently recover the difference between average costs and efficient prices. Setting this levy has much in common with setting indirect taxes to raise revenue in a fair and least distortionary way, and as such the theory of public finance offers clear guidance on the principles to follow, which have been set out in section 2. Their translation into the practical task of setting prices and regulated tariffs stresses the importance of passing through such levies to final consumers and avoiding net metering, which, with most intermittent generation and all embedded generation connected to distribution networks, is increasingly leading to highly distorting outcomes in the type, size and location of new generation.

The case for supporting renewables, set out in section 3, requires a careful assessment of the reasons for support (and how much for each immature technology). That in turn should influence the forms of support and their proper integration into the market. Auctions can deliver superior solutions that bureaucratically set tariffs for RES, but the efficient pricing of networks and ancillary services are increasingly important for reducing the cost of higher volumes of RES.

Capacity and renewables auctions for suitably designed long-term contracts are an attractive way of addressing informational asymmetry and capture of regulators, but impose additional threats, in that an auction can settle contracts in an afternoon, and unlike regulatory settlements of network tariffs that can be reset after five or so years, the contract design can persist for decades. If the network price signals are inefficient, the consequences can lock in costly inefficient outcomes for lengthy periods, so it is increasingly important for regulators to become familiar with these price-setting theories and to ensure that they collect the relevant data to implement them.

References

ACER, (2013). *ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012*, Nov., Ljubljana at http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202013.pdf

Atkinson, A.B. and J.E. Stiglitz, (1980, 2015). *Lectures on Public Economics*, Princeton University Press

Ausgrid, (2011). *Distribution Loss Factor Calculation Methodology Paper*. www.aer.gov.au/system/files/Ausgrid%20-%20Distribution%20Loss%20Factors%20-%20Methodology%202011-12.doc

Awad, M., K. E. Casey, A. S. Geevarghese, J. C. Miller, A. F. Rahimi, S.M., A. Y. Sheffrin, M. Zhang, E. Toolson, G. Drayton, B. F. Hobbs, & F. A. Wolak, n.d. "Economic Assessment of Transmission Upgrades: Application of the California ISO Approach", at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Economic%20Assessment%20of%20Transmission%20Upgrades_Application%20of%20the%20California%20ISO%20Approach_Awad,%20Casey,%20Geevarghese,%20Miller,%20Rahimi,%20Sheffrin,%20Zhang,%20Toolson,%20Drayton,%20Hobbs,%20Wolak.pdf

BEIS, (2016). *Generation Cost Report*, at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/566567/BEIS_Electricity_Generation_Cost_Report.pdf

Bergman, L., G. Brunekreeft, C. Doyle, N-H. von der Fehr, D. M. Newbery, M. Pollitt, and P. Regibeau, (1999). *A European Market for Electricity?* London: Centre for Economic Policy Research

Boiteux, M., (1949). "La tariffication des demandes en pointe: Application de la théorie de la vente au cout marginal". *Revue Générale de l'Electricité*, 321-40

Boiteux M., (1956). "Sur la gestion des monopoles publics astreints a l'equilibre budgetaire". *Econometrica* 24, 22-40. Translated into English as: "On the management of public monopolies subject to budget constraints". *Journal of Economic Theory* (1971) 3, 219~ 240.

Bolinger, M., J. Seel, and M. Wu, (2016). "Maximizing MWh: A Statistical Analysis of the Performance of Utility-Scale Photovoltaic Projects in the United States", pre-print of an article submitted to *Progress in Photovoltaics: Research and Applications*, available at https://emp.lbl.gov/publications/maximizing-mwh-statistical-analysis

Böhringer, C., K.E. Rosendahl, H. B. Storrøsten, (2016). "Robust policies to mitigate carbon leakage". *Journal of Public Economics* in press, doi: 10.1016/j.jpubeco.2017.03.006

CEER, (2016). *Principles for valuation of flexibility*, C16-FTF-09-03, at http://www.eurelectric.org/media/285609/c16-ftf-09-03_principles-for-valuation-of-flexibility.pdf

Coase, R., (1937). "The Nature of the Firm". *Economica*. 4 (16): 386–405. doi:10.1111/j.1468-0335.1937.tb00002.x

Deaton, A. and N.H. Stern, (1986). “Optimally Uniform Commodity Taxes, Taste Differences and Lump-Sum Grants”, *Economics Letters*, 20, 263-266.
DECC, (2010). *Electricity Market Reform: A consultation document*. Dec, at http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx
DECC, (2013a). *Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime*, *Report by NERA for DECC*, at https://www.gov.uk/government/publications/nera-economic-consulting-report-changes-in-hurdle-rates-for-low-carbon-generation-technologies accessed 20/7/15
DECC, (2013b). *Quarterly Energy Prices September 2013* at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/244580/qep_sep_13.pdf
Diamond, P.A. and Mirrlees, J.A., (1971). “Optimal Taxation and Public Production, Part 1. Production Efficiency”, *American Economic Review*, 611, 8-27.
EC, (2016). *Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity*, COM(2016) 864 final at http://ec.europa.eu/energy/sites/ener/files/documents/1_en_act_part1_v7_864.pdf
EPRI, (2016). “Budgeting for Solar PV Plant Operations & Maintenance: Practices and Pricing”, at http://prod.sandia.gov/techlib/access-control.cgi/2016/160649r.pdf
Fraunhofer, (2016). *Photovoltaics Report*, Fraunhofer Institute for Solar Energy Systems, at www.ise.fraunhofer.de
Galal, A., Jones, L. Tandon, P. and Vogelsang, I., (1994). *Welfare Consequences of Selling Public Enterprises: An Empirical Analysis*, Oxford University Press.
HMG, (2013). *Energy Act 2013*, at https://www.gov.uk/government/collections/energy-act
HoC, (2016). The Carbon Price Floor, Briefing Paper CBP05927, House of Commons Library
Hogan, W., J. Rosellon, and I. Vogelsang, (2010). “Toward a Combined Merchant-Regulatory Mechanism for Electricity Transmission Expansion.” *Journal of Regulatory Economics*, DOI 10. 1007/s 1 1 149-010-9123-2
Honoré, A,, (2016*), South American Gas Markets and the role of LNG*, OIES Paper NG 14, October, at https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/10/South-American-Gas-Markets-and-the-Role-of-LNG-NG-114.pdf
IEA, (2012). *World Energy Outlook 2012*. International Energy Agency, Paris, France.
ITRPV, (2016). *International Technology Roadmap for Photovoltaic Results Seventh Edition 2016* at http://www.itrpv.net/Reports/Downloads/2016/
Jamasb, T., (2007). “Technical change theory and learning curves: Patterns of progress in electricity generation technologies”. *Energy J*. 28, 51–72.
Joskow, P., (2013). “Symposium on ‘Capacity Markets’.” *Economics of Energy and Environmental Policy*, 2(2). v-vi.
King, D., J. Browne, R. Layard, G. O’Donnell, M. Rees, N. Stern & A. Turner, (2015). *A Global Apollo Programme to combat Climate Change*, LSE, at http://cep.lse.ac.uk/pubs/download/special/Global_Apollo_Programme_Report.pdf

Laffont, J-J. and J. Tirole, (1993). *A Theory of Incentives in Procurement and Regulation*, Cambridge: MIT Press

MIT, (2016). *Utility of the Future: An MIT Energy Initiative response to an industry in transition*. At https://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf

Newbery, D.M., (1990) "Growth, Externalities and Taxation", *Scottish Journal of Political Economy*, Nov, 305-26.

Newbery, D. M., (1995). "Power Markets and Market Power", *Energy Journal* **16**(3), 41-66

Newbery, D.M., (2005). "Electricity liberalisation in Britain: the quest for a satisfactory wholesale market design", *Energy Journal*, Special Issue on European Electricity Liberalisation, ed. D. Newbery, 43-70 http://www.iaee.org/en/publications/speciali.aspx

Newbery, D.M., (2006). "Electricity Liberalization in Britain and the Evolution of Market Design", ch 4, pp109-144, in F.P. Sioshansi and W. Pfaffenberger (eds.) *Electricity Market Reform: An International Perspective*, Amsterdam: Elsevier, ISBN13 978-0-08045-030-8

Newbery, D.M., (2012a). "Reforming Competitive Electricity Markets to Meet Environmental Targets", *Economics of Energy & Environmental Policy*, **1**(1), pp 69-82

Newbery, D.M., (2012b) "Contracting for wind generation", *Economics of Energy & Environmental Policy*,**1**(2) pp.19-36

Newbery, D.M., (2013). "Evolution of British electricity market and the role of policy for the regulation toward low carbon future", Ch.1, pp3-33 in *Evolution of Global Electricity Markets: New paradigms, new challenges, new approaches*, Ed. F. P. Sioshansi, Elsevier

Newbery, D.M., (2016a). "Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors", *Energy Policy*, 94, 401–410. Doi: http://dx.doi.org/10.1016/j.enpol.2015.10.028

Newbery, D.M., (2016b). "Tales of Two Islands - Lessons for EU Energy Policy from Electricity Market Reforms in Britain and Ireland", *Energy Policy* available online at http://dx.doi.org/10.1016/j.enpol.2016.10.015

Newbery, D,M., (2017). "How to judge whether supporting solar PV is justified", EPRG Working Paper 17NN, at http://www.eprg.group.cam.ac.uk/eprg-working-papers/

Newbery, D.M. and Grubb, M., (2015). "Security of Supply, the Role of Interconnectors and Option Values: insights from the GB Capacity Auction", *Economics of Energy & Environmental Policy*, 4(2), 65- 81. doi http://dx.doi.org/10.5547/2160-5890.4.2.dnew

Newbery, D.M. and M.G. Pollitt, (1997). "The Restructuring and Privatisation of the CEGB- Was it worth it", *Journal of Industrial Economics*, XLV (3), 269-303

Newbery, D. M. and J. E. Stiglitz, (1981). *The Theory of Commodity Price Stabilization: A Study in the Economics of Risk*, Oxford: Clarendon Press, ISBN 0-19-828417-0

Newbery, D.M. and Strbac, M., (2016). "What is needed for Battery Electric Vehicles to become socially cost competitive?" *Economics of Transportation* 5, 1–11, at http://dx.doi.org/10.1016/j.ecotra.2015.09.002

Nordhaus, W.D., (2014). "The Perils of the Learning Model for Modeling Endogenous Technological Change". *The Energy Journal*, 35(1): 1- 13

NREL, (2016). *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016*, by R. Fu, D. Chung, T. Lowder, D. Feldman, K. Ardani and R. Margolis, National Renewable Energy Laboratory (NREL), at http://www.nrel.gov/docs/fy16osti/66532.pdf?utm_source=NREL%20Report%20Shows%20U%2ES%2E%20Solar%20Photovoltaic%20Costs%20Continuing%20to%20Fall%20in%202016&utm_medium=email&utm_content=nrel&utm_campaign=NewsRelease

Ofgem, (2017). *Minded to decision and draft Impact Assessment of industry's proposals (CMP264 and CMP265) to change electricity transmission charging arrangements for Embedded Generators: Consultation*, 1 March, at https://www.ofgem.gov.uk/system/files/docs/2017/03/minded_to_decision_and_draft_impact_assessment_of_industrys_proposals_cmp264_and_cmp265_to_change_electricity_transmission_charging_arrangements_for_embedded_generators_0.pdf

Pérez-Arriaga, I.J., Rubio, F.J., Puerta, J.F., Arceluz, J. & Marin, J., (1995). "Marginal pricing of transmission services: An analysis of cost recovery". *IEEE Trans. Power Systems*,10(1), 546-553

Pollitt, M.G., (2012). "The role of policy in energy transitions: Lessons from the energy liberalisation era", *Energy Policy*, 50, 128–137

Ramsey, F., (1927). "A Contribution to the Theory of Taxation," *Economic Journal*, 37, (March), 47-61.

Rosellón, J. and H Weigt, (2011). "A dynamic incentive mechanism for transmission expansion in electricity networks: Theory, modeling, and application". *The Energy Journal*, 32(1), 119-148

Rubin, E.S., I. M.L. Azevedo, P. Jaramilloa, & S. Yeh, (2015). "A review of learning rates for electricity supply technologies." *Energy Policy*, 86, 198–218

Rubio-Oderiz, F.J., and I.J. Pérez-Arriaga, (2000). "Marginal Pricing of Transmission Services: A Comparative Analysis of Network Cost Allocation Methods". *IEEE Transactions on Power Systems*, 15 (1): 448–54.

Samuelson, P. A., (1954). "The Theory of Public Expenditure", *Review of Economics and Statistics* 36, 386–389.

Schweppe, F.C., Caramanis, M.C., Tabors, R.D., Bohn, R.E., (1988). *Spot Pricing of Electricity*, Springer.

Steinhilber, S., (2016). *Onshore wind concession auctions in China: Instruments and lessons learnt*. AURES Report D4.1-CN, March.

Stoft, S., (2002). *Power System Economics: Designing Markets for Electricity*, Wiley.

US EPA, (2016). *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

Vázquez, C., Rivier, M., Pérez-Arriaga, I. J., (2002). "A market approach to long-term security of supply". *IEEE Transactions on Power Systems*, 17 2: 349-357.

Weiller, C. M., & Pollitt, M. G. (2014). "Platform Markets and Energy Services". EPRGWP 1334, https://doi.org/10.17863/CAM.5357

Williamson, O. E., (1981). “The Economics of Organization: The Transaction Cost Approach,” *The American Journal of Sociology*, 87(3), pp. 548-577.

Williamson, O. E., (1985). *The Economic Institutions of Capitalism: Firms, Markets, Relational Contracting*. New York, NY: Free Press.

Appendix: Social Cost-benefit Analysis of PV Subsidies[1]

1 Learning-by-doing

The one-factor learning model has the unit cost at date t, c_t, given by

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

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:

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

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.

1.1 Predicting unit costs

ITRPV (2016) provides the reference data used here and discussed at more length in Newbery (2017). 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 value would be US\$ 1,050/kW$_p$. 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$_p$yr,[2] as US\$ 44/MWh, and this can achieved in sunny areas of the US. European capacity factors (CFs) are lower and 1,000 hrs/yr or 11.4% CF. Estimating capacity factors is not straightforward as it depends not only on location but also the size of the array.[3]

[1] This is an abbreviated version of Newbery (2017).

[2] i.e. 23% CF, but this appears to be for tracking panels. Bolinger 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.

[3] See 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 PV CFs are more relevant.

2 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 current PV capacity, which degrades at rate δ, (Jordan et al. 2013), and L be its lifetime. PV generation is hk_t, where h is the equivalent full hours output per year. PV output grows at rate g until date T. Total accumulated production of PV capacity is K_t, and this determines the level of accumulated learning to date t according to (1). The amount of age v capacity remaining at t is $I_{t-v}e^{-\delta v}$, so if $\psi(x,T) = \int_0^T e^{-xt}dt = (1-e^{-xT})/x$,

$$\begin{aligned}
I_t &= I_0 e^{gt}, \quad K_t = \int_{-\infty}^{t} I_u du = K_0 e^{gt} = I_t/g, \\
k_t &= I_t \int_{-L}^{0} e^{(g+\delta)u} du = I_t \psi(g+\delta, L), \; \frac{k_t}{K_t} = g\psi(g+\delta, L) < 1. \\
c_t &= c_0 (K_t/K_0)^b = c_0 e^{gbt}, \; y_t = hk_t. \\
C_t &= c_t I_t = c_0 I_0 e^{g(1+b)t}. \qquad (3)
\end{aligned}$$

The value of the external learning benefits is the present discounted value (PDV) of future cost reductions, discounting at the social discount rate, r. Future investment costs are $c_t I_t$, given by (3). A change in current investment, dI_t, will increase all future values of $K_u, u > t$, by dI_t, so the net present discounted cost of this change at $t = 0$, A_0, assuming steady growth until T, will be:

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

where I_0/K_0 has been replaced by g. As $b < 0$, the second term is negative, indicating future cost reductions. As a fraction of the current investment cost, this spill-over *benefit* at date zero is

$$(1 - \frac{c_m}{c_0}) \frac{(1 - e^{-(r-bg)T})}{1 + r/(-bg)}. \qquad (4)$$

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 the first term would increase towards unity, and for large $(r - bg)T$, the learning benefit would tend to $(1 + r/(-bg))^{-1}$, or 64% with these figures.

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. Whether or not PV can displace fossil *capacity* depends on the coincidence of its output with peak demand. 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 MWh_e[4] of fossil generation at date t is Γ_t, which developers expect to rise at rate I, so $\Gamma_t = \Gamma_0 e^{It}$, 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 of 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,[5] the net present discounted cost of a unit investment at date zero when discounting at a commercial discount rate R is:[6]

$$f_0 = c_0 - m_0, \quad m_0 = \int_0^L e^{-\delta u}[h_u(p_u + \Gamma_0 e^{Iu}) + \tau P_u]e^{-Ru}du, \tag{5}$$

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. 1 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. 1, 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. 1, col C).

[4] Subscript $_e$ 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.

[5] This 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.

[6] The 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 (WACC in fig. 1) given the various contracts for output and capacity designed to minimise the cost of the support.

2.1 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, in which case h would be initially high, but as good sites are preferentially used first, h_t 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 (Newbery, 2016). Similarly, the value of PV capacity, τP_t, might fall as additional PV competes less successfully with existing PV, although it may be necessary to pay more for flexible conventional generation to compensate for lower p_t. All these elements can be given decreasing time trends:

$$h_t = h_0 e^{-\zeta t}, \quad p_t = p_0 e^{-\pi t}, \quad \tau P_t = \tau_0 P_0 e^{-\xi t}, \tag{6}$$

so that (5) can be explicitly written and evaluated on constant growth paths:

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

Fig. 1 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, $r = 3\%$, $I = 0.5\%$, $i = 1.5\%$, $P = \$75$/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.

Figure 1: 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	p	$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 I0	dV_0/I_0	$604	$826	$473	$351	$719	$111	$113	$693	$690	$341

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:

$$
\begin{aligned}
V_0 &= -F_0 + S_0, \text{ where } F_0 = \int_0^T f_t I_t e^{-rt} dt, \text{ and} \\
S_0 &= \int_0^T h_t k_t [(p_0 - p_0 e^{-\pi t}) + \gamma_0 e^{it} - \Gamma_0 e^{It}] e^{-rt} dt.
\end{aligned} \tag{7}
$$

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

$$
\begin{aligned}
F_0/I_0 &= c_0[(c_m/c_0)\psi(r-g,T) + (1-c_m/c_0)\psi(r-(1+b)g,T)] \\
&\quad -h_0[p_0\psi(\delta+R+\zeta+\pi,L)\psi(\zeta+\pi+r-g,T) \\
&\quad +\Gamma_0\psi(\delta+R+\zeta-I,L)\psi(\zeta+r-I-g,T)] - \tau_0 P_0 \psi(\delta+R+\xi,L)\psi(\xi+r-g,T).
\end{aligned} \tag{8}
$$

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

$$
\begin{aligned}
S_0/I_0 &= h_0\psi(g+\delta,L)[p_0\{\psi(\zeta+r-g,T) - \psi(\zeta+r+\pi-g,T)\} \\
&\quad +\gamma_0\psi(\zeta+r-g-i,T) - \Gamma_0\psi(\zeta+r-g-I,T)].
\end{aligned} \tag{9}
$$

The two components of V_0/I_0 (equations (8) and (9)) and their sum are shown for various parameter values in Fig. 1. (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).

2.2 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 (6), and an average value of $\tau = 5\%$, as shown in Fig. 1 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.

2.3 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 (7), noting that I_0 affects all future costs, but k_t is only affected for L periods, and $dk_t/dI_0 = e^{-\delta u}$, so:

$$\frac{dV_0}{dI_0} = -\frac{dF_0}{dI_0} + \frac{dS_0}{dI_0}, \tag{10}$$

where

$$\begin{aligned}
\frac{dF_0}{dI_0} &= f_0 + \int_0^T I_t \frac{df_t}{dI_0} e^{-rt} dt = f_0 + gbc_0(1 - c_m/c_0)\psi(r - gb, T), \\
\frac{dS_0}{dI_0} &= \int_0^T [h_0 e^{-\zeta u} \frac{dk_t}{dI_0} \{(p_0 e^{-\pi t} - p_0) + \gamma_0 e^{it} - \Gamma_0 e^{It}\}] e^{-rt} dt \\
&= h_0[p_0\{\psi(r + \zeta + \delta, L) - \psi(r + \zeta + \delta + \pi, L)\} + \gamma_0 \psi(r + \zeta + \delta - i, L) - \Gamma_0(r + \zeta + \delta - I, L)].
\end{aligned}$$

The effects of raising the current rate of investment are shown in the last line of fig. 1. 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.

References

EPRI (2016). "Budgeting for Solar PV Plant Operations & Maintenance: Practices and Pricing" at http://prod.sandia.gov/techlib/access-control.cgi/2016/160649r.pdf

ITRPV (2016). *International Technology Roadmap for Photovoltaic Results Seventh Edition 2016* at http://www.itrpv.net/Reports/Downloads/2016/

Jordan, D.C. and S.R. Kurz (2013). "Photovoltaic Degradation Rates — An Analytical Review", *Progress in Photovoltaics: Research and Applications*, 21(1), 12–29

King, D., J. Browne, R. Layard, G. O'Donnell, M. Rees, N. Stern & A. Turner (2015). *A global Apollo programme to combat climate change*, LSE, at http://cep.lse.ac.uk/pubs/download/special/Global_Apollo_Programme_Report.pdf

Newbery, D.M. (2016). "A simple introduction to the economics of storage: shifting demand and supply over time and space", EPRG WP 1626, at http://www.eprg.group.cam.ac.uk/wp-content/uploads/2016/10/1626-Text.pdf

Newbery, D.M. (2017). "How to judge whether supporting solar PV is justified", EPRG Working Paper 17NN, at http://www.eprg.group.cam.ac.uk/eprg-working-papers/

NREL (2016). *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016*, by R. Fu, D. Chung, T. Lowder, D. Feldman, K. Ardani, and R. Margolis, National Renewable Energy Laboratory, at http://www.nrel.gov/docs/fy16osti/66532.pdf?utm_source=NREL%20Report%20Shows%20U%2ES%2E%20Solar%20Photovoltaic%20Costs%20Continuing%20to%20Fall%20in%202016&utm_medium=email&utm_content=nrel&utm_campaign=NewsRelease