ELECTRICITY GENERATION COSTS AND INVESTMENT DECISIONS: A REVIEW

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Contents

1   Introduction

Under public ownership the costs of electricity generation were estimated for two reasons: *first* to identify the least-cost option for investment, and *second* to analyse pricing policies. At one time, comparisons of the costs of alternative ways of generating electricity were based on the expected average—or 'levelised'—costs per kWh of output, in which the annualised capital costs plus fuel and maintenance costs over the year are divided by annual kWh output. This method is still used to provide a first-order estimate of costs when comparing generating plant.

In a series of papers and books in the 1950s and 1960s economists and engineers addressed a number of limitations of the method[2], for example to allow for

- Diurnal, weekly and seasonal fluctuations in demand, when the idea of using the load duration curve for cost analysis was introduced;

- Seasonality in supply, for example in systems with hydro plant;

- Changes in the plant factors of plant already on the system when new plants were introduced. In turn:

- Changes in plant factors over a new plant's lifetime as it too was shifted down the merit order following the introduction of further plant on the system in later years;

- Uncertainties as to plant availability and future demands; and, more recently:

- The analysis of investments under uncertainty using portfolio analysis and options valuation.

The models became increasingly used by the electricity generation industry around the world in the 1960s up to the era of market liberalisation beginning in the 1990s, and still are used in countries where electricity markets are publicly owned. They were also used to analyse the marginal costs of supply to provide a better basis for pricing policies, for example to support the case for peak-load and seasonal pricing.[3]

With the liberalisation of electricity markets in the 1990s companies became price takers, which led them to focus on the rate of return to investment. This is the discount rate that equates:

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[2] The papers and texts of the French economists and engineers such as Giguet (1951), Massé and Gribrat (1957) Massé (1962) and Bessière (1969) were particularly influential, as were those of Turvey (1965, 1969, 1971), Berrie (1967) and van der Tak (1966) and Manne (1959, 1960). The literature is a long one; see my review: Anderson (1972, reprinted in Turvey and Anderson 1977).
[3] Again the literature is a long one, and owes a lot to the French economists noted above and to Turvey (1969, 1971). Turvey's and my book (1977) again provides a review with case studies.

(a) The present value of the expected output times the market price over the lifetime of the plant, with

(b) The present value of the capital costs of the plant, plus the annual maintenance costs, plus the output of the plant times its fuel and other variable costs.

Estimates of (b) still require an analysis of how the plant will operate in an interconnected system and, for this reason, methods of estimating costs developed before markets were liberalised remain relevant for—and are still used by—private investors. For example, simulation methods can be used to assess how a plant's load factor might be expected to change over time, or how its returns will be affected by other plant being brought onto the system.

For the private sector the importance of the rate of return for appraising investments means that companies necessarily pay considerable attention to the price of electricity when making their investment decisions, including the effects of any price incentives that are in place for environmental purposes or to support the development of new technologies. This 'joined up' thinking, of looking at prices and costs together to estimate the rate of return did not occur under public ownership (the best efforts of some economists notwithstanding), where decisions as to which plant to invest in were taken independently of—and usually by departments independent of those responsible for—decisions over prices.[4]

For the analysis of energy and environmental policies the relevant question is thus how decisions on regulatory arrangements and environmental policy affect the rates of return to private investments. This is an elementary and obvious step forward from an exclusive focus on costs, but as shown below its implications for the way we analyse policies are not trivial. Uncertainties and risks with respect to prices are if anything greater than those concerning costs and stem from may sources—variations in demand and supply situations, the traded prices of gas and coal, factors affecting energy security, uncertainties as to future policies, and uncertainties as to the prices associated with instruments of policy, such as with the prices of tradable permits and obligations.

The paper first discusses estimates of the levelised costs of selected technologies and the corresponding rates of return under alternative assumptions as to prices. It then shows how such estimates can be refined to allow for the variability of demand, changes in plant dispatching schedules, storage and so forth. Next it considers the effects of environmental policies and innovation on costs and the rate of return. Finally it considers the issues posed by uncertainty and risks. By beginning with the simple cases of levelised costs and average returns, and then by gradually peeling away assumptions, the aim is to gradually reveal the fundamentally different perspective that arises when the rate of return becomes the focus of investment.

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[4] Calculations of the average or, in American parlance, the 'fair' rate of return were a way of assessing the whether prices were too high or too low rather than for assessing the desirability of the investments, given that the utilities were monopolies (Turvey and Anderson 1977, Chapter 10).

2   Levelised Costs

Formula

The total annual costs (*C*) of providing output from a generating plant equal its annualised capacity costs, plus fixed annual costs plus variable operating and fuel costs:

$$C = A(n,r) \cdot c \cdot X + m \cdot X + f \cdot Q / \eta \qquad (1)$$

Where *A(n,r)* is the annuity rate for a plant life of *n* years and an interest rate of *r*, *c* is capital cost per kW installed, *X* the installed capacity, *m* the fixed annual cost (mostly maintenance) per unit of capacity, *f* the cost of fuel, *Q* the annual kWh output and *η* the plant efficiency.

The levelised cost ($\overline{C}$) is simply this expression divided by *Q.* Often the relation is expressed in terms of the plant's load factor (or plant factor, *L*), which is defined as being the kWh output of the plant divided by the kWh that would be generated if the plant operated at full capacity throughout the year: $L = Q / 8760 X$. Or:

$$\overline{C} = A(n,r)c / 8760L + m / 8760L + f / \eta \qquad (2)$$

This is the basis of the unit cost estimates often quoted for coal- and gas-fired plant, nuclear power and wind farms, for example by the IEA (1993 and 2005), the Royal Academy of Engineering (2004) and the Department of Trade and Industry (2003). In the case of wind farms, further adjustments are made for the added capital or 'backup' capacity and fuel and operating costs imposed on the system to cope with the intermittency of the plant, as discussed in a previous report by the UKERC (Gross et al, 2006).

An Example

The merits of the approach are that it provides simple—if only 'ball-park'— estimates of average costs subject to approximations that are widely understood. Some examples of recent estimates are provided in Table 1:

Table 1: Recent Estimates of Levelised Costs for New Plant in the Period 2005-15

	Gas (combined cycle)	Coal (pulver-ised fuel)	Coal-IGCC with CCS	Nuclear	Wind--onshore	Wind--offshore
Capital cost, £/kW	400	800	1600	1770	800 b/	1330 b/
Plant life, years	30	40	25	40	25	20
Fixed operating costs, £/kW/year	12	40	80	105	28	48
Variable operating costs p/kWh	0	0.6	0.9	0	0	0
Thermal Efficiency, %	50	45	35	a/	-	-
Plant factor, %	90	90	85	85	30	35
Fuel input costs, p/kWh	1.4	0.5	0.5	a/	0.25 c/	0.25 c/
Levelised costs, p/kWh	**3.6**	**2.6**	**4.8**	**3.9**	**4.4**	**6.8**
Uncertainty ranges:						
-- capital costs	± 15%	± 15%	± 25%	± 30%	± 20%	± 30%
-- fuel costs	± 50%	± 30%	± 30%	-	-	-
--levelised cost as % levelised cost of marker d/	-	-	67 ± 30%	50 ± 50%	62 ± 35%	120 ± 60%

Source: Data for the Stern Report, reviewed by DTI the Carbon Trust and others.
Stern (2007). The gas fuel costs correspond to £4/GJ and the costs of coal to
£35/ton. The discount rate is 10%.
a/ Fuel costs and assumptions as to the effects of efficiency are included in the
fixed operating costs.
b/ Includes allowance for backup costs = 20% of installed capacity with open
cycle GT as backup.
c/ Balancing costs per kWh.
d/ The 'marker' is the fossil fuel technology offering the lowest cost of generation;
it can be coal or gas, depending on coal or gas prices (the range of which is
shown in the table).

The uncertainties are appreciable, as can be seen in the last three rows. Gas
prices have swung over a 3:1 range in recent years, while the capital cost
uncertainties in nuclear power and offshore wind span a nearly 2:1 range. The
bottom row shows the computed range of costs when uncertainties in fuel and
capital costs are combined. It shows the cost difference between the low carbon
technology and the marker technology (coal or gas, depending on prices) as a
percentage of the costs of the marker technology.

The probability distribution of relative costs is illustrated by another example in Figure 1 below, for the case of nuclear power and combined cycle gas plant based on the data in Table 1. On this basis there is a chance of nuclear plant being less expensive than CCGTs, as the recent UK Energy Review (DTI (2006)) concluded; but there is a yet larger chance of it being more expensive; a lot will depend on future gas prices and the ability of industry to build plant at cost and on schedule. The cost difference is better described as being 20 ± 40 %.

Figure 1: Relative levelised costs of gas-fired and nuclear plant
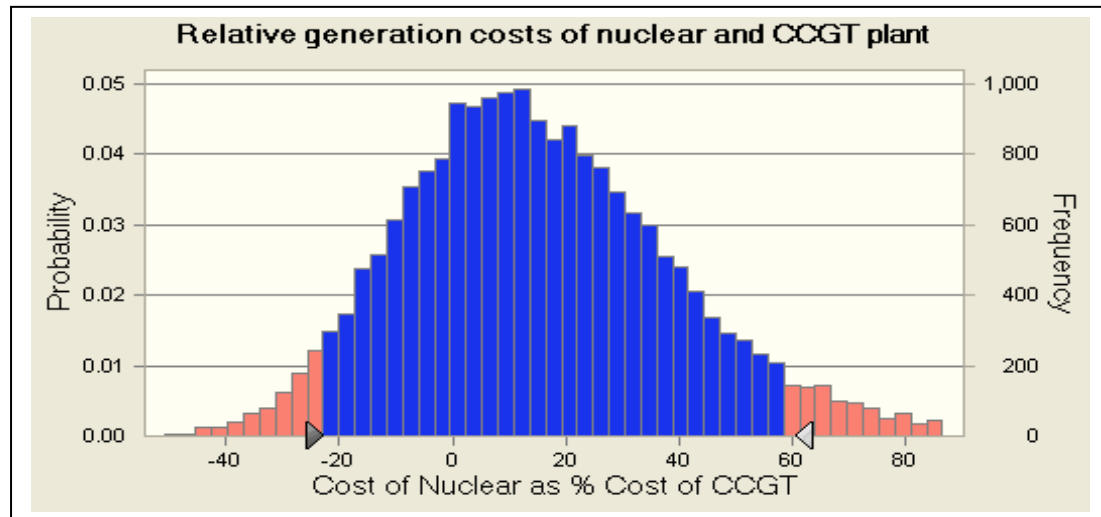
Basis: Monte Carlo runs using data in Table 1. The costs were assumed to be normally distributed but with the lower tail of the costs of gas cut off at £2/GJ. Crystal ball software. 20,000 trials

A systems analysis is required to make fully satisfactory comparison of costs. But, to digress briefly, approximate though such calculations are they indicate that, for the recent proposals for new investments in nuclear power to have a satisfactory likelihood of success, a significant price incentive will be needed for nuclear investments to be financially viable; the required incentive will be determined as much by the spread of the cost estimates as by their mean value. The same applies other low carbon technologies.

3 The Rate of Return to Investment Based on Levelised Costs

There is a rate of return counterpart to the estimates of levelised costs, which is the discount rate which equates the average annual sales to the levelised costs. It is easily calculated. Some estimates are shown in Table 2, based on the cost data in Table 1 and the following assumptions:

1.   Average price set by levelised cost of CCGT at gas prices of £/2GJ.

2.   Ditto but with gas prices of £4/GJ

3.   Average price set by minimum levelised cost across all technologies

4.   Average price set by levelised cost of CCGT at gas prices of £4/GJ plus a carbon price of £100/tonC (applied to CCGT and pulverised coal without CCS).

The calculations are simple, and are intended only to draw attention to the influence of the level of electricity prices on the rate of return. The influence of price structures and variations in demand will be considered in the next section.

Table 2: Rates of return to investment as a function of the average price of generation, with and without a carbon price of £100/ton

Average Price Basis = Lev. Cost of:	Price, p/kWh	Price carbon, £/ton	Gas (comb-ined cycle)	Coal (pulver-ised fuel)	Coal-IGCC with CCS	Nuc-lear	Wind: onshore	Wind: off-shore
1. P = levelised cost of CCGT (gas = £2/GJ)	2.1	0	10.0	-0.3	-4.7	3.0	3.2	1.1
2. P = levelised cost of CCGT (gas = £4/GJ)	3.6	0	10.0	13.5	1.3	8.9	7.5	3.8
3. P = min. l.c. across all technologies	3.2	0	3.2	10.0	-0.2	7.4	6.4	3.1
4. P = l.c. of CCGT (gas = £4/GJ) + £100/ton C	4.6	100	10.0	-1.2	5.7	13.1	10.5	5.8

Source: Author's own calculations, available on a spreadsheet if required.

Row 1 helps to explain the 'dash for gas' in the 1990s, when gas prices were low; the prospective returns to new investments in all other technologies in that period were poor. The higher gas prices since then (row 2) has improved the prospects of all other technologies, particularly coal and to a lesser extent nuclear power and onshore wind; and there is the possibility that, if the higher gas prices were

to persist (row 3), coal would become the price setter, and the returns to new investments, both in CCGTs and in the low carbon options, would all fall. A carbon tax of around £100/tonC (row 4) would, as one would expect, substantially favour both gas-fired generation and the low carbon technologies.

The corresponding probability distributions for the rates of return for nuclear power and offshore wind are shown in the two charts in Figure 2 below. They are very wide, and the effect of including price uncertainties in the analysis widens the distributions as compared with those for the costs of the individual technologies. The inclusion of a carbon tax would shift both these distributions to the right (see also Table 2 row 4).

Not shown in the charts is the much narrower distribution of the returns to investments in natural gas. As the working paper by Will Blyth (2006) has shown, the short-run price of generation from natural gas is covariant with the price of electricity generation on account of the location of gas-fired plant in the merit order. It thus enjoys a degree of protection from the volatilities of gas prices, something the low carbon technologies do not. If further uncertainties are introduced in the pricing policies, as an incentive for investments in the low carbon technologies—e.g. uncertainties in the commitment of governments to the policies, and volatilities in the price of marketable emission permits or in the price of an 'obligation' to use these technologies—the distributions would be yet more widely dispersed, though with a higher mean, a factor that needs to be weighed when comparing the effectiveness of alternative instruments of policy, as discussed in Section 6 below.

Figure 2: Estimated 'Levelised' Rates of Return to Onshore Wind and Nuclear Power (2005)
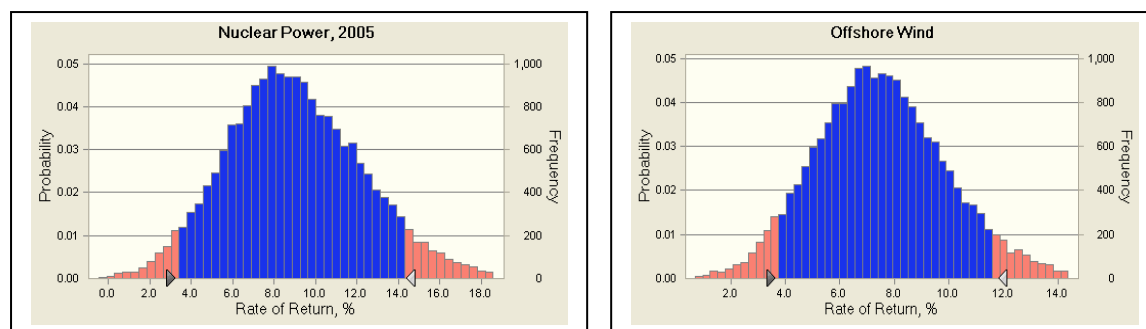
Source: Author's own calculations, available on a spreadsheet if required.. Assumptions same as for table 1 with prices set by the levelised cost of generation from gas (gas prices varying over the range £2/GJ to £6/GJ).

4.   Refining the Calculations of Costs and Rates of Return

It is not difficult to move from the averaging of costs and returns to the more realistic case in which prices and costs vary continually. The system models used for the costing of investments under public ownership of the industry can still be used in background calculations for the appraisal of private investments. As Will Blyth (2006) in his working paper for this project comments:

> "Companies will typically run a detailed model of the electricity system they are considering making an investment into, with every major generation plant represented. Ranges will then be included for the major variables that affect the financial performance of the plant, including fuel prices, CO_2 and other environmental costs. Different scenarios for investment behaviour of other players in the market may also be incorporated."

The models also retain their relevance for the monitoring and analysis of the prices that emerge under competition and for estimating the marginal costs of— and the incentives required for—meeting environmental and other goals.

Peak and Base-Load Plant on a Thermal System
The main problem is to allow for changes in prices and costs arising from hour-to-hour, weekly and seasonal changes in demand and plant availability. For any particular investment, the net present worth of cash flows or the rate of return can be computed in the usual way by estimating the present worth of cash flow receipts, minus the present worth of the annual expenditures on fuel and maintenance, minus the capital costs:

$$\sum_t (1+r)^{-t}(P_t - F_t)\cdot H_t \cdot X - C \cdot X \qquad (3)$$

P_t denotes prices in period t, F_t the variable maintenance and fuel costs per unit of output, r the interest rate, H_t the hours of operation in the period, C the unit capital cost and X the capacity. H_t summed over all hours in a year divided by 8760 gives the plant factor. For simplicity the annual fixed maintenance costs are ignored.

Now consider the criterion for investing in a peak load plant having low capacity but high fuel costs. Early analyses of the slopes of cost and load duration curves soon established the least cost criterion for peaking plant on thermal systems, which is that the extra fuel costs of peaking plant over the peak hours (H_{peak}) need to be less than the savings in investment costs:

$$A(n,r)(C_{base\,load\,plant} - C_{peaking\,plant}) \ge (f_{peaking\,plant} - f_{base\,load\,plant})\cdot H_{peak} \qquad (4)$$

where $A(n,r)$ is the annuity rate for plants with a lifetime of n years.

Under competitive arrangements the same criterion will be met by investors following a rate-of-return or net present worth criterion. Prices at peak will (or should, in competitive markets) reflect the marginal costs of supply plus a random element reflecting departures of demand and supply from expected conditions:

$$P_{t,peak} = A(n,r) \cdot C_{peaking\ plant} / H_{peak} + f_{t,peaking\ plant} + \varepsilon_t \tag{5}$$

The rate of return follows straightforwardly by finding the value of r which equates the present worth of $P_{t,peak} - f_{t,peaking\ plant}$ with $C_{peaking\ plant}$ over the lifetime of the plant. The rate of return to investments in peaking plant would be higher, and the peak price of electricity lower, than would be the case if plant with higher capital and operating costs per unit of electricity generated over the peak were installed (5).[5] Investment choices for the peak period based on the rate of return criterion are thus fully consistent with the long-standing criterion for cost-efficiency, familiar from the analysis of load duration and generation cost curves.

The same can be said for investments in thermal plant that begin their lives on base load and gradually move down the merit order as new plant are introduced. For a plant meeting peak and off-peak demands the rate of return is based on the comparison of the present worth of:

$$P_{t,peak} \cdot H_{t,peak} - f_{t,peak} \cdot H_{t,peak} + P_{t,off-peak} \cdot H_{t,off-peak} - f_{t,off-peak} \cdot H_{t,off-peak} \tag{6}$$

with the capital costs of the plant. (Again, other annual components of costs are omitted to avoid clutter.) The criterion for investments to meet the peak load is a special case of this, in which $H_{t,off-peak} = 0$.

The capacity margin
The above analysis of peak load plant is of course a simplification. It considers only *average* conditions over the peak—average hours of peak, the average load over this period, average prices, average levels of capacity utilisation, average fuel costs, average plant availability and so forth. In practice:

- All these quantities vary appreciably and randomly over the peak period, and very often peak load plant may be operating well above average expectations if demands are unusually high and/or plant availability on the system is low; or operating little or not at all if demands are low and plant availability is high.

- The duration of the load over the peak period varies continuously. The duration of the absolute peak demands can be very short (a few hours) even in systems where there is quite a long peak period overall (Figure 3).

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[5] Since the sum of the cost terms on the right hand side would be greater for any discount rate; thus the equalising discount rate (the rate of return) would have to be lower to achieve the same price; or alternatively the price higher to obtain the same rate of return.

- Ensuring a reliable supply requires a margin of spare capacity on the system such that there is an *expectation* that some peaking plant will not be called upon in this period at all (Figure 3).

All these factors can and do lead both to considerable price volatility and add to the uncertainties facing generators concerning whether to retain old plant as backup, in situations where it may not be used at all, or to invest in peak load plant. The criterion for new investment or to retain old plant for this purpose is simply stated. It is that: *The present value of expected revenues over the peak > the present value of expected costs.*

Figure 3: The Load Duration Curve and the Capacity Margin
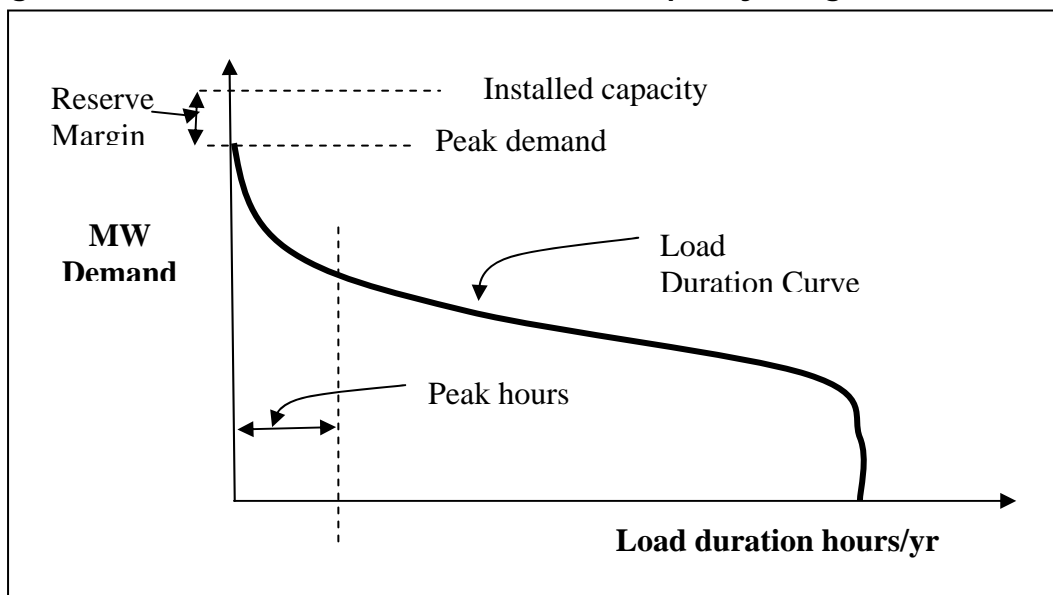
In theory, competitive markets will bid up the price over the peak such that the rate of return to investment in reserve capacity will meet the threshold rate of return of private sector companies. In practice, when there is pressure on the reserve margin, the price can be bid up to very high levels on account of the inelasticity of demand in the short-run, as illustrated in the figures in Annex 1, which has led industry to express fears that there could be a political backlash against the policy in times of scarcity.[6] Testimony by the National Economic Research Associates to a House of Lords Science and Technology Committee summarised the issue very well:[7]

> "There is a well-known market paradigm in which competitive market pricing rewards all investment in a least-cost and diverse portfolio of generation … However, this paradigm relies heavily on the ability of short term electricity market price to soar to very high levels during a shortage, in order to remunerate investment in generation capacity that only runs at peak times, and indeed to remunerate all investments in capacity needed to meet peak demand."

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[6] See the House of Lords Report, *Renewable Energy: Practicalities*. Vol 1, HL Paper 126-I, Science and Technology Committee, 4th Report of Session 2003-04, pp 59-61
[7] Ibid. p. 60

The question of whether the issue is best resolved by competition alone or, for example, by competition supplemented by a capacity payment for standby plant remains undecided. The pure economic argument favours no such payment; but providing for system reserves is not and never has been a purely economic issue.

Baseload plant

If we define average values of price, fuel (and other annual components of costs) and hours of operation in obvious ways:

P = Average price over all hours of operation in a year
f = Average variable costs over all hours of operation in a year
H = Hours of operation per year

and use them in the preceding expression, then the present worth of revenues is simply $(P \cdot H - f \cdot H)/A(n,r)$. Comparing this with the capital cost C gives the rate of return, while $f + A(n.r) \cdot C/H$ gives the levelised cost.[8] Thus under reasonable assumptions for calculating average prices, fuel costs and hours of output, estimates of the levelised costs and rates of return are not an unreasonable guide to costs and returns, at least for *base load plant.*

Intermittent plant

Levelised cost calculations, with adjustments for the costs of intermittency, may also be used for intermittent plant such as wind, *provided* the weighted average price is based on the prices obtaining when the plant is operating. The appropriate price ($\overline{P}$ say) to use is:

$$\overline{P} = \sum_t H_t \cdot P_t / \sum_t H_t \qquad\qquad (7)$$

Storage

The treatment of storage—primarily in systems with hydro-electric plant—requires simulation models to allow for the inter-relation of operating decisions between periods. In the models developed for system planning in thermal systems, the objective function, for each development plan under consideration, takes the form of minimising the present value of operating and fuel costs summed over all plant on the system subject to capacity constraints (capacity sufficient to peak demand), output constraints (the sum of outputs from the available plant sufficient to meet instantaneous demand), and to the constraints on the output of each plant (output less than or equal to available capacity).[9] With hydro storage on the system the objective function is the same, but there is an additional set of constraints linking storage conditions, inflows and outflows between periods: the amount of energy in storage (S_t) is less than or equal to the amount left in storage from the previous period, plus the energy inflow (E_t) in the period, minus the energy used ($U_t.H_t$) minus losses to evaporation and leakages (L_t):[10]

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[8] H = the availability factor times 8760.
[9] The MARKAL has an optimising routine of this kind, and may also include plant capacities as decision variables in the objective function.
[10] It is generally an equality, unless there are spillages.

$$S_t \le S_{t-1} + E_t - U_t \cdot H_t - L_t \qquad (8)$$

This can lead to a large number of constraints since *t* needs to be divided into seasons (often months) and some grouping of hours in the day to distinguish between peak, base and intermediate loads. For hydro storage models to solve this problem have been in use for a long time in the industry and are still used as research tools.[11]

Attempts to apply such models for the storage of energy from wind and other intermittent resources run into the difficulty that the time intervals need to be much shorter, perhaps hourly or half-hourly. But, once again, the iterations of a competitive market provide a simplification, since market prices can be used to value the inputs and outputs on the assumption that private agents (as happens with inventory decisions in practically all other markets) will arrive at their own optimum storage policies based on operating experience and, in more complex cases, using firm-level models of inventory management familiar from the literature on Operations Research. The present value of investments in storage with a capital cost *C* is simply:

$$\sum_t (1+r)^{-t} (P_t \cdot U_t \cdot H_t - P_t \cdot M_t \cdot H_t) - C \qquad (9)$$

Where U_t and M_t are the rates of output and input respectively, and are adjusted for losses and operating or handling costs.

5.   External Costs and Benefits

Limits to the traditional analysis
The costs of meeting local environmental constraints are often embodied in the costs of the power plant themselves, for example in the capital costs of coal plant with precipitators to reduce particulate matter emissions and scrubbers to reduce sulphur emissions. But for abating CO_2 emissions a different approach is needed since it is necessary to examine the costs of—and the price incentives required for—investments in alternatives such as nuclear power, renewable energy, and coal or gas with carbon capture and storage. In addition, each of the alternatives faces constraints: biomass with the amount of land it requires; onshore wind with the availability of sites, nuclear power with long-lead times, waste disposal and decommissioning; renewable energy with the 'intermittency problem' at high levels of market penetration. There is a body of evidence and analysis which suggests that a portfolio of alternatives will be required.[12] Uncertainties and risks associated with each technology also argue for a diverse portfolio.

The problem can be formulated as one in which the objective function is to identify an incentives structure that maximises the present worth of investment and operating decisions subject to the constraints faced by each technology. This

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[11] Almeida (2004) PhD thesis. "Overcoming Intermittency: a model of wind and hydro energy in NE Brazil."
[12] Reference: Pacala and Socolow (2004, 2006), DTI Economics Paper (2003), Stern Review of the Economics of Climate Change (2006)

would follow the traditions of investment analysis in the industry before market liberalisation. It also yields the rising, stepped-shaped marginal-cost-of-abatement curve found in many studies over the past 15 years.

Such curves provide a useful summary of information on costs at a point in time, but as they stand they are not a sufficient basis for policy. The main issue is that the marginal costs are assumed to decline exogenously over time, independently of investment. Yet the literature on the technologies for abating carbon emissions has numerous examples of costs declining with scale economies and 'learning-by-doing' as investment and operating experience is accumulated. The figure in Annex 2 attached is frequently cited.[13] The rankings of the technologies may also change over time depending on the relative rates of technical progress. The upshot is that the marginal cost-of-abatement curve may rise at first, peak and then decline as knowledge and experience accumulate and technologies are improved, and then rise again as diminishing returns set in (Figure 3).

Figure 3: Marginal Cost of Pollution Abatement with Exogenous and Endogenous Technical Change
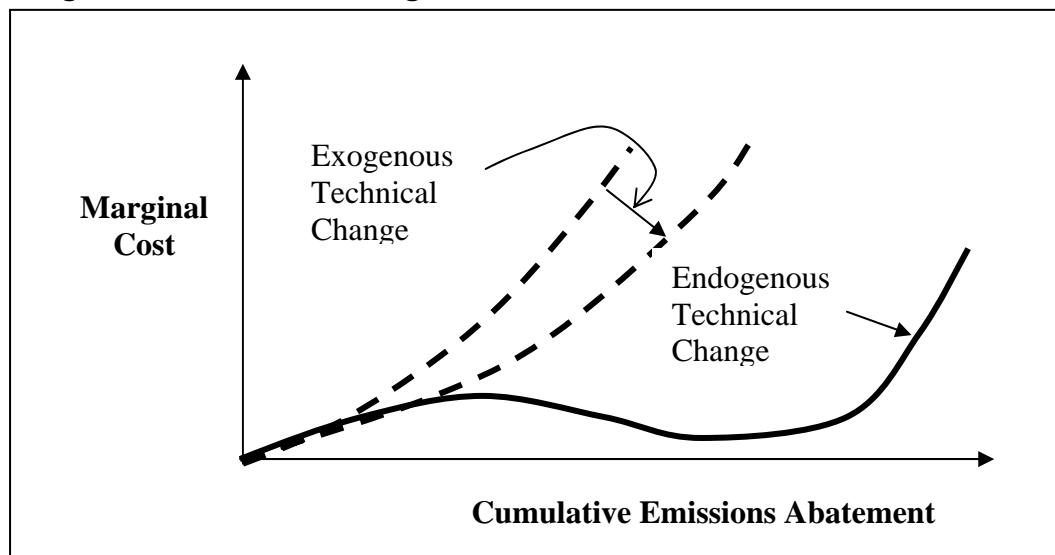
Endogenous Technical Change in Pollution Abatement
When technical change is exogenous investments in any one period can be evaluated by comparing the present worth of revenues with the present worth of costs, where the revenues include both revenues from sales plus the price effects of environmental policy. Sometimes the environmental policies will be embodied in the prices, but it is convenient to distinguish between the revenues per unit output (P_0 say) that would arise in the absence of environmental policies from those that arise as a consequence of the latter (e_0 say); the subscript 0 refers to

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[13] The effects of progress on costs tend to be much more marked in the early stages of a technology's development because that is the phase when the opportunities for discovery and innovation are most abundant. A common leaning curve function for example takes the form: $C_t = C_0 X_t^{-b}$ where X_t is cumulative investment, such that the rate of change in costs is $\dot{y}/y = -b\,\dot{X}/X$. When markets are small they may increase tenfold or even hundred-fold when expanding from say 0.1% to 10%, such that the rate of decline is far higher than when their markets are mature.

the present period. Denoting costs per unit output by C_0, an investment I_0 is worthwhile, according to the traditional analysis, if:[14]

$$(P_0 + e_0)I_0 \geq C_0 \cdot I_0 \qquad (10)$$

This is to assume however that the investment has no other external effects—for example on the costs of later investments. But with learning-by-doing such effects can be significant, and it is more correct to characterise the problem as one in which investment experience feeds back positively on future investment by reducing costs, further stimulating investment and so forth, as in Figure 4 below:

Figure 4: The Feedback of Investment Experience on Costs and Investment
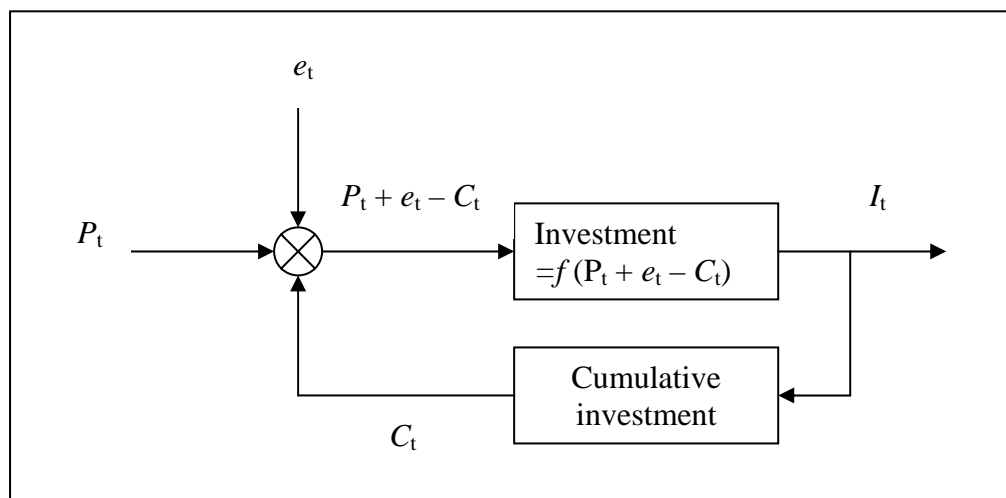
The criterion for an investment in period 0 with these effects is derived in Annex 3; it is not (10) but:

$$P_0 + e_0 + \sum_{t=1}^{\infty} (1+r)^{-t} I_t \{b \cdot C_t + b \cdot \beta \cdot (P_t - C_t + e_t)\} / X_t \geq C_0 \qquad (11)$$

The term within the summation sign represents the positive externalities of the investment; these are the expected gains arising from future investments stemming from the cost reductions made possible by investments in period 0. It has two components. The first represents the direct benefits of lower future costs arising from learning by doing (b is the learning curve co-efficient). The second represents the private plus environmental benefits ($P_t + e_t - C_t$) arising from the extra investment induced by the price reductions (β is the price elasticity of substitution between fossil fuels and the low carbon alternative). The magnitude of the benefits is directly proportional to the volume of expected use (I_t).

The possibility of additional environmental benefits arising from innovation (represented by the second term associated with e_t in the summation sign) means that the traditional cost benefit approach of counting only those benefits directly associated with the investment (represented in this case by e_0 only)

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[14] It is convenient to regard these quantities as present worths. See annex.

understates the environmental benefits of an investment. In fact, when learning and substitution elasticities are large the understatement can be appreciable, as indicated shortly.

How are the positive externalities of innovation (including the environmental benefits associated with them) best internalised? Environmental taxes (or tradable permits) at the time of the investment *and* the expectation of them in later periods should account for the benefits represented by e_t for all periods t = 0, 1,… But what of the other component—the cost-savings benefits of innovation? *If* there is a well functioning patent system *and* there is the expectation of stable policies, there is the possibility of the positive externalities being internalised by businesses taking out options or 'strategic positions' in anticipation of future rewards—of 'virtue creating its own reward' so to speak. Investors can and do look ahead, and there is no reason why this should not be the case for the development of low carbon technologies. But if e_t is volatile and subject to political and other uncertainties the process discussed above can easily spiral inwards and lead to nothing. The crucial conditions therefore are stability and durability in environmental policy and a system of patenting and property rights that is supportive of innovation.

The term within the summation sign is divided by the cumulative amount of investment, $X_t = X_0 + \sum_{t>0} I_t$ where X_0 is the initial capacity installed. Since the initial level of installation is generally small the positive externalities are largest in the earlier periods; but they show rapidly diminishing returns once the technologies take root and market shares increase—even if, as seems to be the case for many energy technologies, the learning parameter (*b*) remains unchanged.

Illustrative Calculations
The substitution elasticity (*β*) can reach very high levels and have the effect of a switching function when the differences between the costs of competing technologies are small. When cost and product price differentials between new and incumbent technologies are large, even large shifts in relative costs and prices can lead to little substitution. But when costs converge the substitution effects may become very large. The shift in the UK to CCGTs in the 1990s, in which output grew from <1 to 120 TWh in a decade while the outputs of all other plant fell from 300 to 230 TWh was associated with a small price differential of ~ 0.5 p/kWh or 25% of the generation costs of pulverised coal, and indicated a substitution price elasticity ≥ 4.0. In LP models such as MARKAL the substitution elasticity can even be infinite near the point of substitution, given the criterion: invest in technology A if its costs are less than or equal to the alternatives but not if they are greater. The results change kaleidoscopically with small changes in assumptions when cost differentials are narrow, but not if they are large, when they might not change at all.

The calculations in Table 3 show the effects of alternative assumptions on the present value of costs for a simple substitution function:

Table 3: Effects of Substitution Elasticities on Positive Externalities

Component	$\beta = 1$	$\beta = 2$	$\beta = 3$	$\beta = 4$	$\beta = 5$
Price of generation (P_0), p/kWh	3.5	3.5	3.5	3.5	3.5
Initial cost of low carbon technology (C_0) p/kWh	5.0	5.0	5.0	5.0	5.0
External cost of carbon (e_0), based on coal and £150/tonC	1.7	1.7	1.7	1.7	1.7
Positive externalities as % C_0 */	30	36	42	48	52

*/ Learning curve parameter $b = 0.3$, which corresponds to a learning rate of 20%, the percent reduction in cost for each doubling of the cumulative level of investment.

The main point is that innovation can give rise to substantial economic and environmental benefits downstream such that a focus on the immediate environmental impact and private returns of a particular investment alone is to understate its benefits.

6.   Cost and Price Uncertainties

The effects of cost and price uncertainties on private investment decisions have been excellently covered in the background papers by Will Blyth and Kirsty Hamilton. Further analysis of risks and the benefits of diversified portfolios has been provided by Shimon Awerbuch drawing on several of his recent papers. The key points concern:

(a)   *The change in perspectives on risks when rate of return calculations replace calculations of relative costs.* Blyth compares two sets of calculations: one showing the range of the relative levelised costs of gas, coal and nuclear stations under alternative assumptions of carbon prices (0/tCO$_2$, £10/tCO$_2$, £17/tCO$_2$, and £25/tCO$_2$) and prices of coal and gas; the other the net present values of the investments under the same assumptions. The results are shown in the left and right hand sides respectively of Figure 5. Blyth comments "The advantage of the NPV approach is that it represents the range of potential financial outcomes for each of the technologies on the same terms, and in the same units that matter to financial backers."

Figure 5: Levelised costs (left hand chart) and net present values (right hand chart) under alternative fuel and carbon price assumptions.
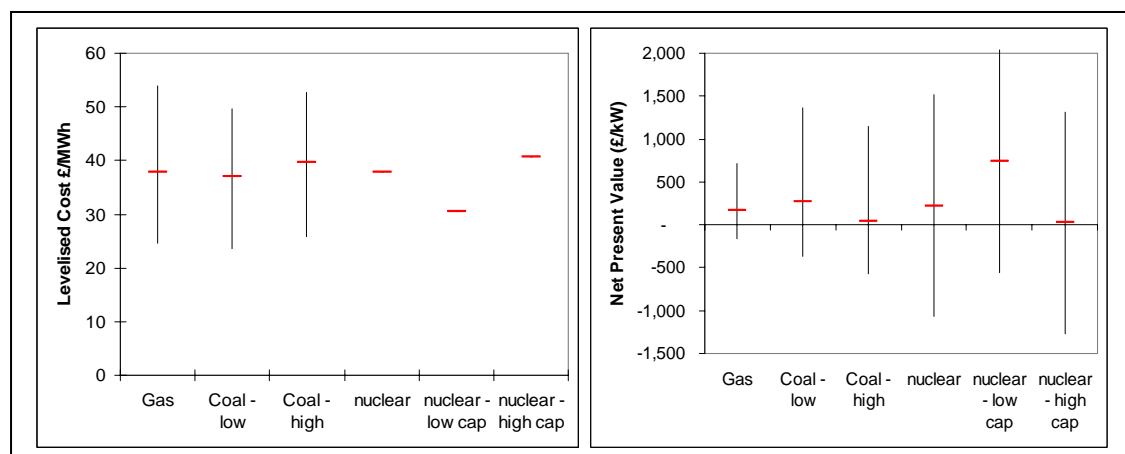
Source: Blyth (2006). The range of fuel and carbon price assumptions was taken from (DTI 2006).

The contrast is striking. Changes in carbon and fuel prices have large effects on the levelised costs of coal and gas, but of course no effect on the costs of nuclear power (or of any other non-carbon technology). But shifts in prices arising from changes in fossil fuel and carbon prices have a large effect on electricity prices because the short-run marginal costs of fossil fuel plant determine the short-run marginal costs of supply and hence prices; this in turn affects the returns to investments in the non-carbon technologies. When levelised costs are compared, it is the non-carbon technologies that look the less risky option; but when the NPVs are compared the non-carbon technologies are the riskier.

I know of no calculation which more vividly illustrates the importance of working with the net present value or rate of return to investment—both for private investors, for whom the calculation is a *sine qua non*, and for policy analysts.

(b)   *The option value of delaying investments when risks are large.* When the uncertainties are large the instinct of investors is to delay a decision if there are reasons for thinking that 'the passage of time' will reduce them—policies may become clearer, costs more settled and the technologies tested and proved or disproved elsewhere. Investment expenditures cannot be reversed once they have been incurred. In these circumstances there is an *option value* to delaying a decision: if the higher risk possibilities turn out not to materialise, the investment can go ahead later with a higher expectation of success; if they do, a loss-making proposition can be avoided. The upshot is that there is a calculable value to a wait-and-see policy, as is illustrated in Blyth's paper (Figure 4 and text). Furthermore, the greater the uncertainties as to the net income flows from an

investment, the greater the incentive to delay. More general results are to be found in the text of Dixit and Pindyck (1994).

If policies themselves add to the uncertainty, then along with volatilities in fossil fuel prices, they will induce further delays, so the policies will need to be stronger than otherwise would be the case if they are to have their intended effect. Kirsty Hamilton puts the issue very well, based on discussions with private investors:

> "policies must affect cash flow if businesses are expected to respond. [A] policy based upon political "aims" is in effect asking investors to speculate about political delivery and that speculation, in finance terms, will demand high or even venture capital level returns, making these technologies even less attractive."

(c)　　　*The option value of investments in new technologies when costs and technical performance are uncertain.* The costs and performance of new technologies cannot be ascertained reliably without investment in them, and there is an option value to investments that provide the required clarifications. This is the rationale for demonstration projects and investments in what are sometimes called 'pre-commercialisation' policies. The benefits of the information and experience gained are additional to the returns obtained from any sales of the projects' outputs.

These benefits become greater when learning externalities are taken into account. Dixit and Pindyck (1994) show that the uncertainties as to the future costs of new technologies are likely to lower the rate of investment in the presence of learning. Hence a desirable adjunct to policies that seek to reap the external benefits of learning-by-doing is an element designed to overcome the additional frictions arising from this source of uncertainty.

(d)　　　*The option value of avoiding irreversible environmental damages.* Just as uncertainties in irreversible investments may argue for delaying investments, so can uncertainties as to irreversible environmental damages when investments are not undertaken argue for bringing investments forward. Hence there is a tension, as Dixit and Pindyck observe, between the option value of postponing irreversible investments and the option value of calling on the same investments to avoid an irreversible effect. In the case of responses to climate change, there is a third factor to be taken into account, just discussed; it is that the costs and performance of the technologies required to address climate change are also uncertain, as are the possibilities for further improvement through RD&D. The PhD thesis by Papathanasiou (2005) and the paper by Papathanasiou and Anderson (2001) develop this argument further using a model in which costs, technological learning and the environmental damage function are all uncertain. In the presence of such uncertainties, the incentives provided by policy may need to be increased for three reasons, not one: to counter a rational resistance by industry to the uncertainties they face as to the returns to new investments; to enable the new technological options to be developed and tested; and to face the risks of irreversible damages if the investments are not undertaken.

(e)   *The benefits of diverse portfolios.* When uncertainties in the returns to investments in particular technologies are large and not highly co-variant with those of other technologies, there is a benefit to diversifying the portfolio of investments. This is a long-standing principle of financial analysis, which Awerbuch (2006) has shown can be well-applied to electricity generation investments. Future gas prices are highly uncertain, as are the costs of electricity from nuclear stations, renewable energy and coal with carbon capture and storage. The uncertainties and risks as to the returns to a portfolio of investments are generally lower than those of a portfolio that concentrates on one or two technologies.

In situations where there are no environmental or learning externalities, companies will reduce the risks themselves through their own policies of asset diversification. But where externalities are important, policies to internalise them will need to include an element to encourage diversification. The same applies to policies addressed to the issue of energy security.

7.   Conclusions

The liberalisation of the electricity market has brought about an elementary but profound change in the ways by which electricity investments are appraised. Under public ownership appraisals were based on the analysis of costs. Under private ownership they are based on the rate of return to or the net present value (NPV) of investments—as economists long argued should be the case. Since the rate of return (or NPV) is derived from the difference between the present value of revenues and the present value of costs, the analysis of costs self-evidently remains relevant and, literally, provides 'half the picture'. However, including prices in the analysis—and price uncertainties in particular—leads to fundamentally different perceptions as to the relative effectiveness of alternative approaches to policy.

A focus on costs alone underestimates the uncertainties and risks of investment, and can be misleading. *Inter alia* it can lead to the dangers of an 'eggs in one basket' policy, if only by understating risks and giving rise to too much confidence in particular options. In risky situations diversification becomes important. Least cost analysis based on statistical principles can avoid such dangers and can also be used to support diversification. Nevertheless, by ignoring uncertainties in prices it understates the risks faced by investors and the ways these are passed through the system.

Inclusion of price uncertainties and also reveals differences in the risks across technologies. For example:

- Fossil fuel plant enjoy some insulation against fuel price volatility because they are the marginal plant on the dispatching schedule and the prices of

electricity rise or fall directly with fuel prices. (The effects of course differ between coal and gas plant.) The returns to nuclear power and renewable energy technologies in contrast are highly exposed to changes in electricity prices brought about by shifts in the prices of fossil fuels.

▪ Volatility in the price of carbon on fossil fuels plant has much the same effect, and will differ between the chosen instrument of policy—e.g. between a carbon tax or a tradable permit scheme.

The more uncertain the returns, the more likely it is that investments will be postponed—the option value of delaying an investment. When externalities or other factors such as the security of supply are unimportant, the decision whether or not to delay, as with a decision on portfolio diversification, is appropriately left to private investors, and there is no good case for intervention. However:

▪ Where environmental and learning externalities are significant the relative merits of alternative policies for internalising the benefits require assessment in terms of the risks they entail for investors. If a policy is to be successful it is important that it does not increase uncertainties and risks. The relative merits of emissions trading schemes versus carbon taxes, and of technology support mechanisms such as R&D and demonstration programmes, tax credits, feed-in tariffs and the RO, all need to be assessed in light of their—often very differing—effects on the price risks faced by investors

▪ Similarly, policies toward energy security need to allow for price risks, whether it is the risks of spikes or troughs in peak period prices arising from capacity shortages or surpluses, or from spikes and troughs in gas and other prices arising from external factors. In a broad sense, energy security issues, both in peak periods, and with respect to imported fuels, are best viewed in terms of their effects on prices.

The investment literature on risks shows that, not surprisingly, the greater the uncertainties with respect to prices, the greater the incentive that will be needed by investors to face the risks of developing the new technologies to respond to an environmental problem; and similarly, the greater the incentive that will be needed to provide for energy security.

There are two implications of the preceding analysis for current research. The first concerns electricity system modelling. Most models, such as the IEA's MARKAL model, still concentrate on costs. They are still valuable analytical tools; but the above analysis suggests that there is a good case for formulating a new generation of models in terms of discounted cash flows rather than discounted costs alone. Whilst this may add to the complexity, it also introduces a major simplification, discussed in Part 3 above. This is that the returns to investments, and also to portfolios of investments, can be analysed directly under alternative market price assumptions, greatly simplifying the algorithms required for optimisation.

The second is that the merits of alternative policy instruments need to be re-evaluated in terms of the risks faced by investors. (The same implication also follows, I believe, from the background papers of Will Blyth and Kirsty Hamilton.) Uncertainties over the strength and durability of a policy are a common factor whichever instrument is chosen, or as some might say, dithered over. But some instruments are intrinsically more volatile than others—marketable permit schemes and obligations versus emission taxes and feed-in tariffs for example—and by adding to risks increase the option value of delaying investments, in situations where a policy may be requiring a more urgent response.

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Annex 1: The Short-Run Price Inelasticity of Demand and its Effects on Prices

Figure A1: Small Shifts in Demand at Peak and Off Peak
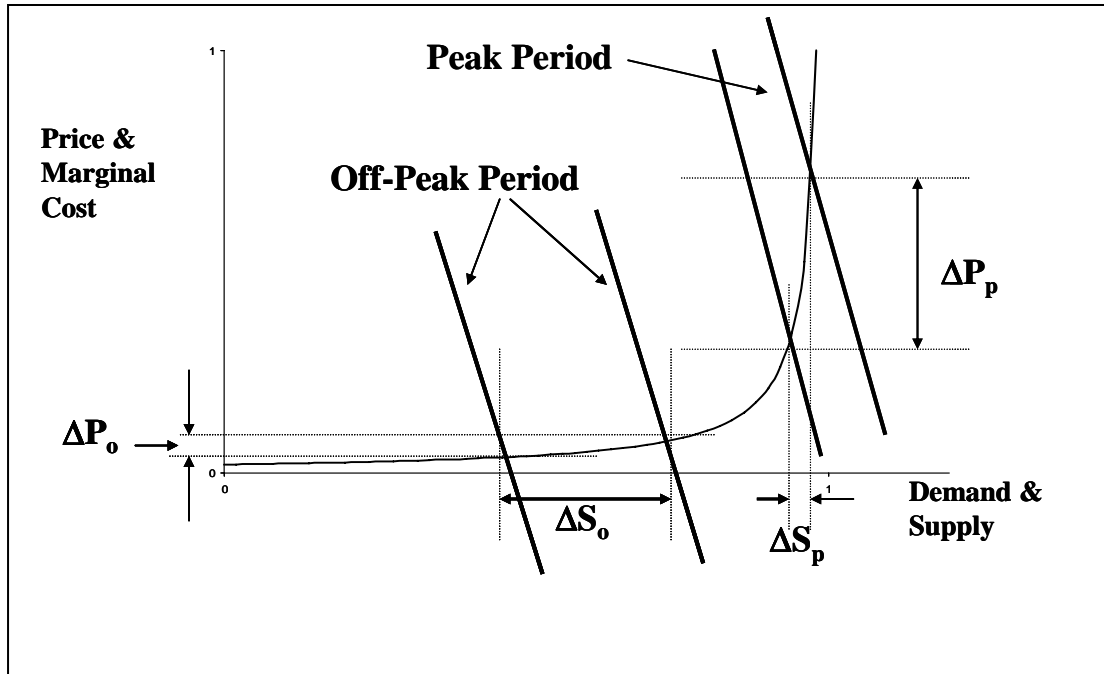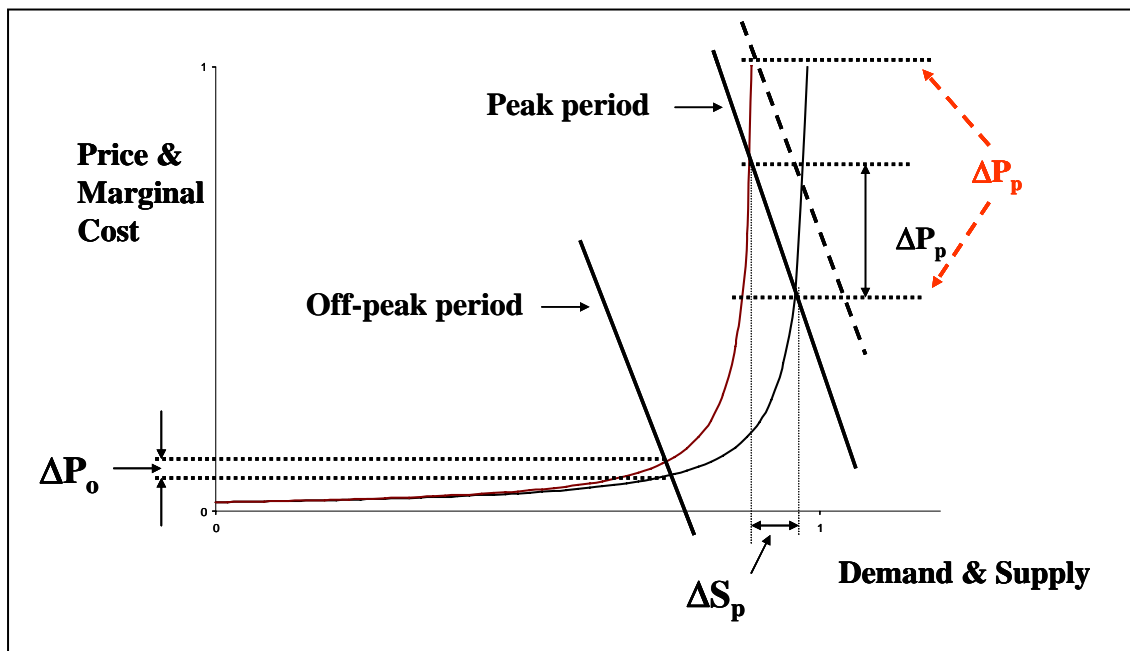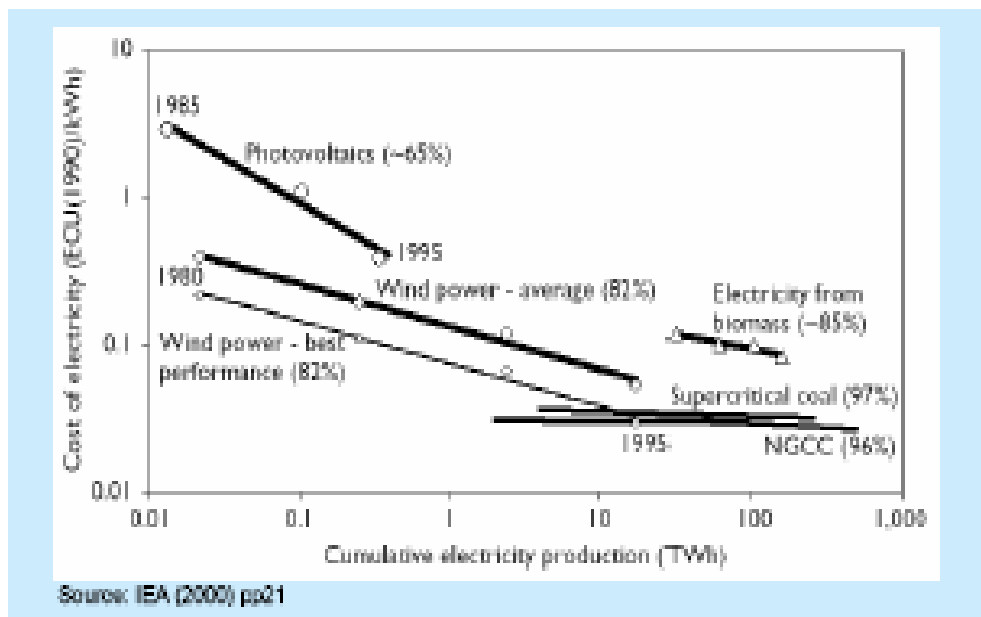

Figure A2: Small Shifts in Supply at Peak and Off-Peak

The main point is that small shifts in demand or supply conditions can lead to big swings in prices over the peak. The effect is likely to be less pronounced at the off peak because supply is highly elastic over this period.

Annex 2. Learning Cost Curves for Selected Technologies

Source: IEA (2000) pp21

Copied from the Stern Report: Box 9.4, p 254

Annex 3: Marginal costs with endogenous technical change

To simplify the algebra it is convenient to capitalise the revenue, benefit and cost streams over the lifetime of a project, and also define the investment, I_t, to be in output units (e.g. kWh generated over the year). Let P_{st} be the average price in year s, t the year of installation, and n the lifetime of the investments. It is convenient to work with a capitalised value of sales per unit of output, P_t, defined as follows:

$$P_t \cdot I_t = \sum_{s=t}^{s=t+n} I_t \cdot P_{ts} (1+r)^{s-t} \quad \text{or} \quad P_t = \sum_{s=t}^{s=t+n} P_{ts}(1+r)^{s-t}$$

(i)

This is the present worth of revenues from sales.

Similarly, the capitalised value of costs (capital expenditures plus the present worth of operating and maintenance costs is:

$$C_t = \sum_{s=t}^{s=t+n} C_{ts}(1+r)^{s-t}$$

(ii)

A low carbon investment will also have the external benefits per unit of output (e_t) of lower CO_2 emissions, with a capitalised value per unit output of:

$$e_t = \sum_{s=t}^{s=t+n} e_{ts}(1+r)^{s-t}$$

(iii)

Now consider a time stream of investments in years t = 0, 1, 2 ……… The present value of the private and external benefits is simply:

$$PV = \sum_t (1+r)^{-t}(P_t - C_t + e_t)I_t$$

(iv)

If the costs of investment in any one period are independent of those in earlier periods, then for any investment introduced in year t = 0, the change in the PV is simply:

$$d(PV)/dI_0 = P_0 - C_0 + e_0$$

(v)

This is the usual view of investment that it should be judged in terms of its own costs and benefits without regard to any dynamic effects from endogenous technical change on the costs and benefits of future investments.

If however the costs of future investments are dependent on the investments before them, then there are further terms to introduce on the right hand side of (v). There are two effects to consider. First there are reductions in the unit costs of future investments arising from investments in the present period. Second, there are price-induced increases in future investments in the technology arising from the reductions in costs. The first effect is usually represented by a learning curve expression of the form:

$$C_t = C_0 \cdot (X_t / X_0)^{-b} \qquad \text{(vi)}$$

$X_t = X_0 + \sum_{t \geq 1} I_t$ is cumulative investment and b is the learning curve co-efficient. The second effect can be represented by a term to represent cost-induced effects on substitution, for example by:

$$I_t = A \cdot C_t^{-\beta} \qquad \text{(vii)}$$

Where β is a substitution elasticity, closely related to the price elasticity of substitution.[15] Using (12) and (13), (11) is superseded by:

$$d(PV)/dI_0 \approx P_0 - C_0 + e_0 + \sum_{t=1}^{\infty} (1+r)^{-t} I_t \{ b \cdot C_t + b \cdot \beta \cdot (P_t - C_t + e_t) \} / X_t \qquad \text{(viii)}$$

The term inside the summation sign, which is positive, represents the *positive externalities of innovation*: these are the present value of the reductions in future costs arising from investments in period 0, plus the environmental benefits arising from the further investments induced by the cost reductions. The (positive external) benefits per unit of output are weighted by the prospective levels of future investments in the technology, such that even if the small, the overall effect can be large if the future levels of investment are large. The appearance of X_t in the denominator represents diminishing returns at high levels of market penetration.

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[15] If costs reflect prices, and I_{ft} and C_{ft} represent investment in and the costs of the fossil fuel alternative, then we would normally write $I_t / I_{ft} = (C_t / C_{ft})^{-\beta}$ where β is the elasticity of substitution. From this $I_t = (I_{ft} / C_{ft}^{-\beta}) C_t^{-\beta}$. In (13) $A = (I_{ft} / C_{ft}^{-\beta})$ and is not strictly constant.