Tyndall°Centre
for Climate Change Research

Modelling Innovation and Threshold Effects In Climate Change Mitigation

Dennis Anderson and Sarah Winne

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Working Paper 59

Modelling Innovation and Threshold Effects In Climate Change Mitigation

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PART I: GENERAL APPROACH

1. Structure of Energy Supply and Demand Equations

The energy demand equations are to include those for all today's major energy carriers plus the possibility of hydrogen emerging as a new energy carrier:

1. Solid fuels: an aggregate of coal and lignite
2. Oil fuels: an aggregate of heavy, middle and light distillates.
3. Natural gas
4. Hydrogen
5. Electricity
6. Biomass—as a 'traditional' fuel, almost wholly in developing countries

Two further demands for energy carriers are often reported: the use of biomass on a commercial scale for liquid fuels and heat, and secondary heat, for example for district heating. As an approximation, both are included in the demands met by 1 and 2. However, both biomass and heat, for example from CHP, are considered to be viable technologies for supplying the above markets.

This is a convenient way of analysing energy demands from historical data since energy statistics are widely gathered and collated according to these classifications, with the exception of statistics on hydrogen, the use of which is currently confined to the oil refinery and chemical industries. In the industrial countries 6 is often not reported since the demands for such fuels are now small; in developing countries, however, traditional biomass use represents nearly 30% of total primary energy consumption.

The demands for all the above carriers except hydrogen are currently represented in the E3MG model. Hydrogen can be derived from gas, oil, coal, biomass and any renewable or other electricity source. Hence any demands for hydrogen produced from these sources will need to be added to the demands currently estimated in the model. Hydrogen, in turn, can be a substitute for oil, coal, gas and biomass in the energy markets. Both the demand for and the supply of hydrogen is treated endogenously in the following model structure.

On the supply side the range of possibilities is very large, and there is considerable scope for substitution between them. Table 1.1 provides a listing, itself being fairly aggregative. Nevertheless, the range of options is impressively large. Possible patterns of substitution are identified by a *y* in the appropriate cells:

Electricity markets: Practically every energy source or every carrier can be used for its generation, depending on costs and availability.

Solid fuel markets: These markets can be supplied by high or low emission ('clean' or 'dirty') coal technologies, with radically differing emissions co-efficients for SO_2, NO_x and PM. Substitutes are gas, to some extent biomass depending on land requirements and supply factors, and, in the longer term, hydrogen.

Oil fuel markets: The history of vehicle emissions in the industrial countries shows that local emission coefficients differ appreciably between the 'clean' and 'dirty' technologies, and further that there are significant downward trends in emissions co-efficients. Gas, either compressed or converted to methanol for the fuel cell vehicle is one set of substitutes, electricity (e.g. for railways) is another, and hydrogen another.

Gas markets: Alternatives to gas itself are coal gas, biomass wastes, albeit on a limited scale, and hydrogen.

Hydrogen: This is a versatile energy carrier which can be generated in a carbon neutral way from coal and gas (with carbon sequestration), biomass, nuclear power and any form of renewable energy, and is capable of being used for electricity generation and as a substitute in the solid, liquid and gas fuel markets.

Traditional biomass: The big step forward for the 2 billion people depending on these sources for heating and cooking is fossil fuels and more sustainable ways of using biomass.

Table 1.1: **Options for Meeting Energy Demands**

Energy Technologies	**Solid Fuels**	**Oil Fuels**	**Gas**	**H_2**	**Elect-ricity**	**Biomass Traditonal**
Carbon Fuels:						
1. Coal—clean	y	y	y	y	y	y
2. Coal—dirty	y		y		y	y
3. Oil fuels—clean		y			y	y
4. Oil fuels—dirty		y			y	y
5. Gas—central	y		y	y	y	y
6. Gas—micro CHP	y		y	y	y	
7. Gas—f-c. vehicle		y				
Carbon neutral:						
8. Nuclear electricity				y	y	
9. Hydro electricity					y	
10. Biomass crops	y	y		y	y	y
11. Biomass wastes: CHP	y		y	y	y	y
12. Wind--intermittent				y	y	
13. Wind—with storage					y	
14. Solar PV--intermittent				y	y	
15. Solar PV—with storage					y	
16. Solar Thrml—intermittent				y	y	
17. Solar Thrml—w/gas					y	
18. Solar Thrml—w/storage					y	
19. Marine—intermittent				y	y	
20. Marine—with storage					y	
21. Geothermal					y	
22. Coal—with carbon sequestration						
23. Gas—with carbon sequestration						
24. Hydrogen—central	y		y	y	y	
25. Hydrogen—micro CHP	y		y	y	y	
26. Hydrogen—f-c. vehicles		y				

A distinction is also made in the above table to allow for the possibility of storage for wind, solar and marine technologies. All three primary energy sources are intermittent and, without storage, their use would be limited to fairly small shares (<20%) of the electricity markets; with storage, their shares would be virtually unlimited. Their potential contribution to the production of hydrogen is also technically unlimited.

Descriptions of the technologies and assessments of their costs are provided later. To begin, however, consider the equations representing substitution.

2. Substitution between the Technology in Question and the ‘Technology of Choice’

For each type of energy demanded there is usually a technology or fuel ‘of choice’—what might be termed a ‘marker’ technology—against which the alternatives will have to compete. The total capital and operating costs of using this fuel per unit output will be used as a basis or *numeraire* for expressing the relative costs of the alternatives. Let P_{it} denote the price of the marker relative to that of the alternative i. Then:

$$P_{it} = \frac{C_t^N (1 + T_t)}{C_{it}(1 + G_t)} \qquad (1)$$

Where C_{it}^N and C_{it} denote the present worth of the costs of using the technologies per unit of output, the superscript N in the former referring to the fuel of choice. T_t represents taxes (carbon taxes say) on the former and G_t taxes on the latter (either may be negative if the energy source is subsidised). At a later stage we will need to allow for the lags between changes in prices and the investment coming into operation, which can be appreciable. (See equation 14 below.) For the moment, let us concentrate on (1), ignoring such lags.

In practice the values of C_{it} vary widely relative to the costs of the marker technology. In the case of coal for electricity generation costs differ appreciably between stations—proximity to the coal fields, the sulphur content of the coal (and thus whether desulphurisation in required), the availability of cooling water, site conditions, civil engineering costs, location relative to the grid and load centres and so forth. The costs of the marker technology may also vary greatly: if the marker technology is a gas-fired plant, its costs like those of coal will differ between sites, and of course with the price of gas.

Similarly the costs of solar energy, biomass and wind vary greatly relative to the costs of the marker technology. There are always so-called niche markets and opportunities where the technology is cheaper than a gas fired power plant: off-grid applications of renewable energy are much-cited examples; others are the use of solar power in sunny regions where there is a good co-incidence between air conditioning demands and the solar peaks, which act to make solar energy economically attractive; and yet others are the gasification of agricultural wastes, in which a better quality of manure is produced, with energy being a by-product. Such applications may be limited, but the point is that, while it may be generally true that the costs of a marker technology may be lower or higher than those of its substitute, this is not true in *every* case. The same conclusion applies to all 26 supply options listed in table 1.1—and to a good many others if further disaggregation were sought.[1] Even with hydrogen, there have been small niche markets for a century, for instance in oil refineries and for the chemical industry; hydrogen surpluses have been used for co-generation for several years. There is nearly always some application of a technology to be found.

The upshot is that the ratio C_{it}^N / C_{it} may show a wide frequency distribution, as depicted in Figure 1.1. While the mean value of the ratio may be well below unity it does not follow that all applications in all locations will be uneconomical.

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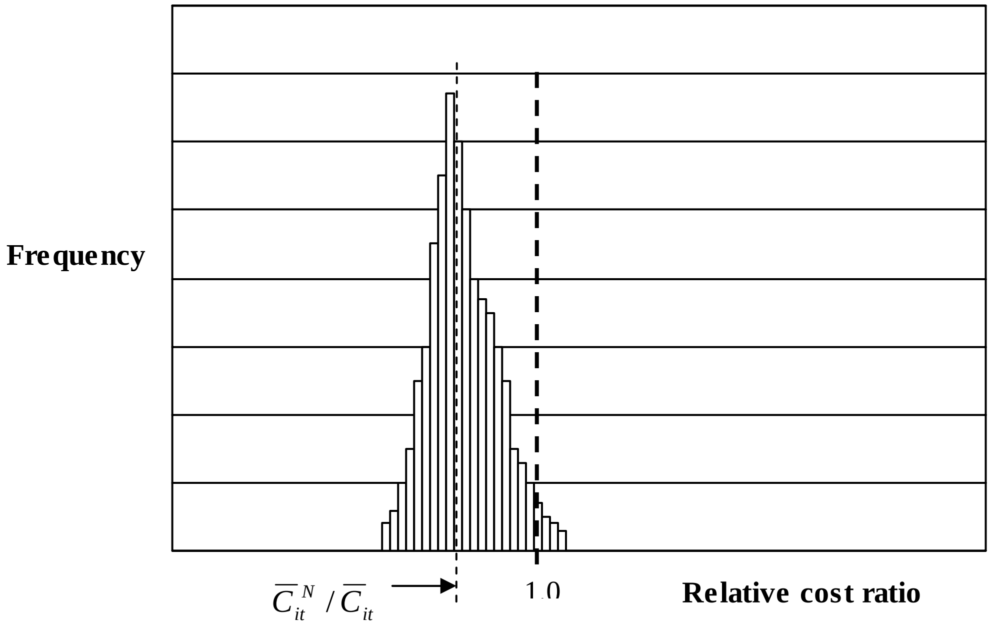
[1] Grubler, Nakicenovic and Victor (1999) present data on the standard deviations of the costs of a range of technologies, drawing on the work of Strubegger and Reitgruber (1995). They find that the variance is appreciably larger when a technology is in the earlier phases of its development and use.

Figure 2.1: Distribution of the costs of a marker technology relative to a substitute



High levels of disaggregation would be needed to capture all reasonable possibilities. This has been done in some instances, for example in the admirable work of IIASA on acid deposition in Europe and Asia, in which every coal and gas fired power plant has been individually represented.[2] It has long been done in the simulation of electricity supply systems in particular countries, for purposes of analysing investment decisions, for example assessing the returns to an investment in a power station based on how it will fit into the dispatching schedules of a large system. However, this is neither a practicable nor a desirable step in macro economic modelling; what we need is a method for working with the most commonly available estimates of the cost ratios discussed, namely the mean value, while recognising that exceptions—in some cases a large number of exceptions exist. This can be done as follows.

Let C_{it}^{N} , C_{it}, now denote the mean values of the costs of the marker and substitute technologies and P_{it} the mean value of the price ratio. An increase of the price ratio can be brought about in two ways. One is to increase the taxes on the marker technology but not on the substitute (say through a carbon tax), or alternatively to subsidise the substitute technology but not the marker. The second is through an innovation which reduces the costs of the substitute relative to the marker. In both cases, the effect is to shift the distribution of costs shown in Figure 2.1 to the right, leading to a larger number of applications of the substitute technology (and conversely if the innovations or tax or subsidy policies favour the marker technology). The share of the substitute technology in the total market as the price ratio P_{it} rises will thus be a cumulative frequency distribution, and will resemble an ‘S’ curve in a good many cases, as suggested in Figure 2.2.

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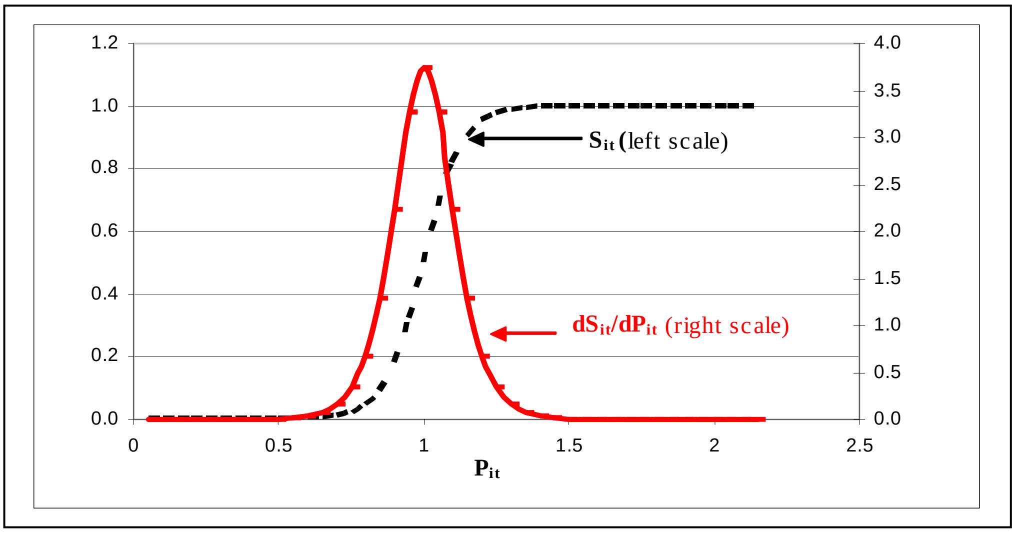
[2] Downing et al (1995) and Shah et al (2000), who provide a review of the application to Asia.

Figure 2.2: Market Share and Rate of Change of Market Share vs Price



For cases where the frequency distributions of the possibilities are approximately symmetrical, the 'S' curves familiar from logistic functions seem suitable. They capture the exponential growth of opportunities in the early phases of expansion and diminishing possibilities as market saturation levels are approached:

$$dS/dP = aS(1-S) \qquad (1)$$

In finite difference form (1) becomes:

$$S_t = S_{t-1} + aS_{t-1}(1-S_{t-1})(P_t - P_{t-1}) \qquad (2)$$

The properties of this equation were explored in a previous paper (Anderson and Winne, 2003). It can be applied to any technology once the marker technology is specified.

3. Estimating the Substitution Parameter from the Frequency Distribution of Substitution Possibilities

There is an inverse relationship between the parameter *a* and the standard deviation of the frequency distribution of the costs of the substitutes. The narrower the distribution, the smaller its s.d. and the larger is the parameter *a*. In circumstances that are not exceptional, the s.d. can be small and the parameter *a* large, and may give rise to rapid switching effects—as happened with the 'dash for gas' in the UK in the 1990s. In Figure 2 the curve $f(P) = dS/dP = aS(1-S)$ can be viewed as the frequency distribution of relative costs depicted in Figure 1. This suggests that we might be able to estimate the parameter *a* from information on the s.d. The function $f(P)$ can be obtained from the values of $S(P)$ given by the familiar solution to (1), which is $S_t = \exp a(P_t - 1)/(1 + \exp a(P_t - 1))$. The relationship between the variance or s.d. of the frequency distribution of the costs of the alternatives and the parameter *a* can then be estimated by numerically integrating $\int (1-P)^2 f(P)dP$ for various values of *a*. The results are shown in Figure 1.3.[3]

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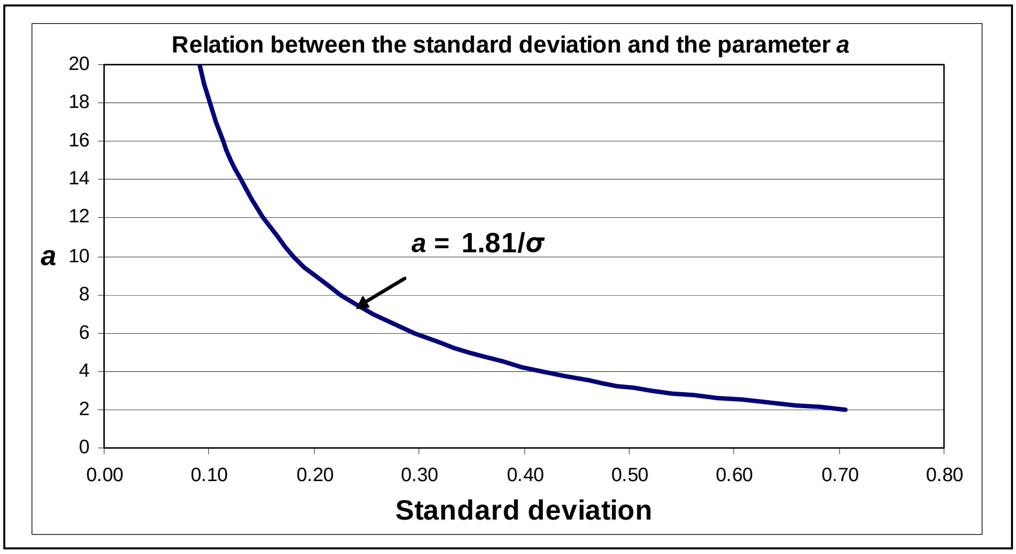
[3] We have since found a text providing an explicit relationship, which is as follows: $a^2 = \pi^2/3\sigma^2 \approx 1.81/\sigma^2$. See Appendix 4.

Figure 3.1



Thus given estimates of the frequency distribution of substitution possibilities we can arrive at an estimate of the parameter *a* and, should we need it, the elasticity of substitution.[4] More important, functional forms such as (1) or (2) enable us to bring the *full distribution* of substitution possibilities for a technology into the analysis. They thus enable us to avoid the errors and omissions that would arise if we were to concentrate on the mean values of the costs and prices alone. Estimates of the mean and s.d. of the distribution of the costs of alternatives can be found in engineering studies.

4. Substitution with Multiple Technologies

The question of the potential size of the market a substitute may meet has so far been ducked. But some technologies, electricity from wind, for example, on account of its being intermittent, and biomass crops, on account of their large land requirements, are practically limited in the share of a market they may ultimately serve. Other technologies—intermittent renewable energy with storage, for example, or for the generation of hydrogen—are capable in theory of serving the whole of an energy market. That the costs might sometimes be extraordinary is another way of saying that the mean of the distribution of relative costs is well to the left of unity in Figure 1.1, and that the distribution may be skewed to the left also.

Consider three technologies competing with the marker technology, and let their shares of the market be S_{1t}, S_{2t} and S_{3t}. When one technology enters the market it diminishes the shares that the other might occupy, such that the shares of the market that the three technologies may ultimately aspire to are given by $(1-S_{2t}-S_{3t}), (1-S_{1t}-S_{3t})$ and $(1-S_{1t}-S_{2t})$ respectively, assuming there is no other restriction on their use. If there is a restriction, such that in practice they may occupy at most some fractions (all < or = 1.0) $\hat{S}_{1t}, \hat{S}_{2t}$ and $\hat{S}_{3t}$ of the market remaining (i.e the total market less the share taken by the competing investments), then the shares they may ultimately aspire to are now given by $\hat{S}_{1t}(1-S_{2t}-S_{3t}), \hat{S}_{2t}(1-S_{1t}-S_{3t})$ and $\hat{S}_{3t}(1-S_{1t}-S_{2t})$. A basis for estimating $\hat{S}_{it}$ is discussed in Section 5 below. Recalling the economic rationale behind the S curve equations, that the growth effect is the product of the share of the market that has already been served, and of how much is still unserved, the following structural form is suggested:

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[4] In the situations we are analysing, the elasticity of substitution is not a constant quantity, as is often assumed, but varies enormously with the level of substitution that has already taken place. (See Anderson and Winne, 2003, footnote 2 page 4).

$$\frac{dS_{1t}}{dP_{1t}} = a_1 S_{1t}\left(\hat{S}_{1t}(1 - S_{2t} - S_{3t}) - S_{1t}\right) \tag{3}$$

$$\frac{dS_{2t}}{dP_{2t}} = a_2 S_{2t}\left(\hat{S}_{2t}(1 - S_{1t} - S_{3t}) - S_{2t}\right) \tag{4}$$

$$\frac{dS_{3t}}{dP_{3t}} = a_3 S_{3t}\left(\hat{S}_{3t}(1 - S_{1t} - S_{2t}) - S_{3t}\right) \tag{5}$$

In finite difference form:

$$S_{1t} = S_{1t-1} + a_1 S_{1t-1}\left\{\hat{S}_{1t-1}(1 - S_{2t-1} - S_{3t-1}) - S_{1t-1}\right\}(P_{1t} - P_{1t-1}) \tag{6}$$

Similarly for S_{2t} and S_{3t}.

It is necessary to estimate the changes in relative costs and prices over time to solve equations such as (6). This will be done once the full model is assembled below. But it is worth looking at the solutions for the special case when all price changes are the same for each technology in each time period, which is the same a solving the familiar logistic equations with $\Delta P_{it} = \Delta t$.[5] This is done in Figures 4.1 and 4.2 for three technologies—the marker technology and two substitutes S_1 and S_2, the former starting out with an initial market share of 5%, the latter 1%. The S curve parameters are identical, and thus so are the frequency distributions of the cost functions. In the first case (Figure 4.1) there is no restriction on the capacity of either technology to substitute for the marker; but since S_1 has an initial start, its further expansion from a larger initial base not only leads to faster expansion as it moves up the S curve, the effect is to increasingly reduce the market opportunities for S_2, with the result that it comes to dominate or ‘lock up’ the market.

In the second case (Figure 4.2) the starting points and the parameters are the same, but a restriction is placed on the market share that S_1 can practically meet—because of physical resource constraints for example, or for technical reasons, such as might arise from intermittency if it is a renewable resource. The effect is that, as the possibilities for S_1 become exhausted, increasing use is made of S_2, though with longer time lags, which comes to dominate the market. It is often argued that this will happen in a renewable energy-hydrogen scenario; once the ‘easier’ but limited renewable energy options such as wind (without storage) and biomass are fully exploited, it will necessary to turn to more expensive options with greater potential.

Figure 4.1: S_{1t} Unrestricted

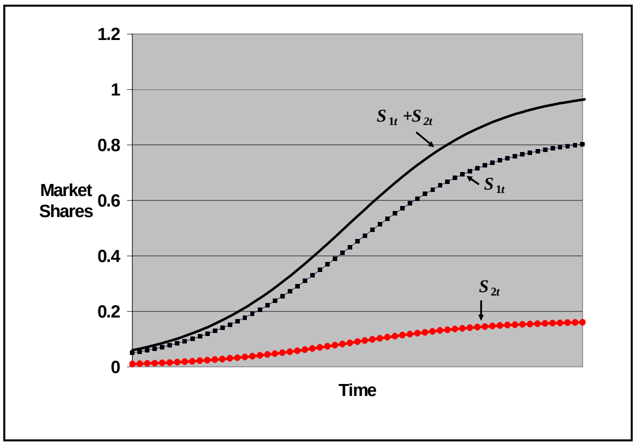
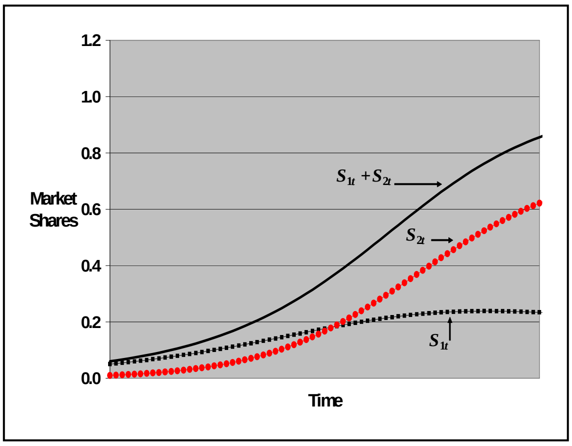


Figure 4.2: **S_{1t}** Restricted



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[5] They can readily be solved recursively. Chaotic behaviour can be avoided by taking small time intervals.

This is a simplified example, intended to try out the above formulation. Similar results arise when several technologies are introduced. In practice the relative rates of growth of the various technologies are highly sensitive to the initial conditions and to any restrictions that might be placed on their use; they are also sensitive to costs, which change over time with investment, technical progress, and of course to prices, which change with costs and taxes.

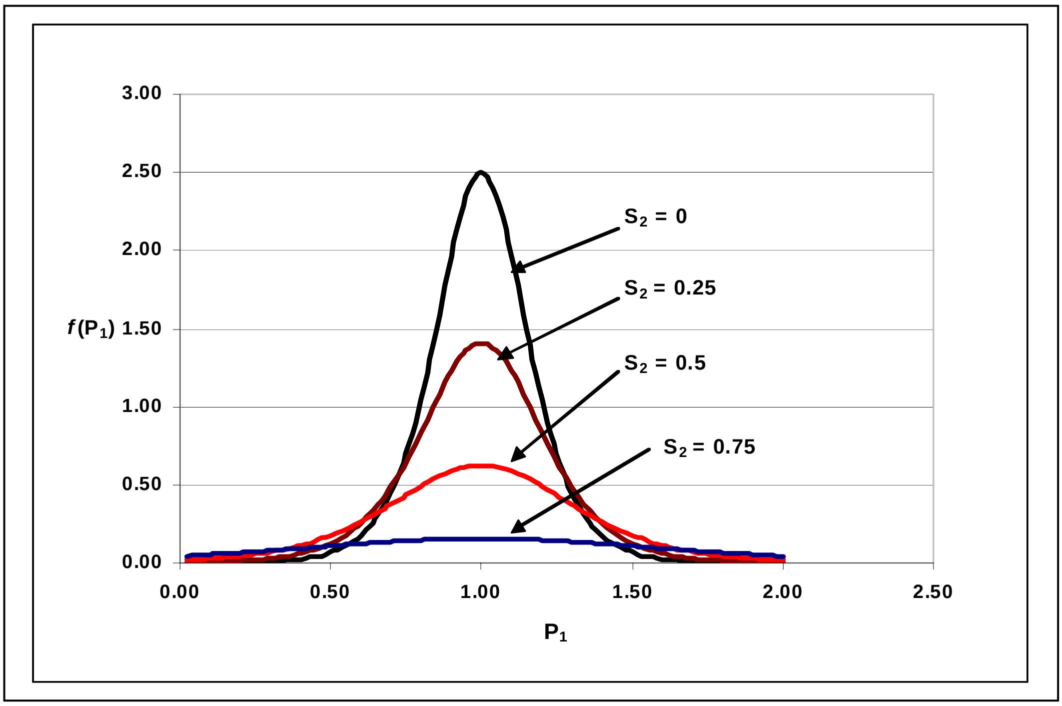
As with the case for a single substitute, discussed in Sections 2 and 3, there is a close relationship between the above equations and those that would follow from functionally related frequency distributions of substitution possibilities. In this case the shares of the market occupied by the competing substitute technologies (denoted by $S_c = S_2 + S_3 + ...$) reduce the scope for S_1 from 1 to $1 - S_c$; the parameter *a* in the single substitute case is replaced by the term $a_1(1 - S_c)$, standard deviation of the possibilities rises to $\sigma \approx 1.8 / a(1 - S_c)$ (see section 3 above), the overall effect being to dampen the rate of substitution of this particular substitute for the marker technology. If the frequency distribution of substitution possibilities for the technology is normally distributed, $\sigma \approx 1.5 / a(1 - S_c)$.

An explicit solution to the multi-technology or multi-variate case is (so far as we know) not possible such that we need to turn to numerical methods. If we hold the market shares of the competing substitute technologies (denoted by S_2) the solution for the substitute in question (S_1)is straightforward (see Appendix 3):

$$S_{1t} = (1 - S_2)\frac{e^{a(P_{1t}-1)(1-S_2)}}{1 + e^{a(P_{1t}-1)(1-S_2)}} \qquad (7)$$

Using this equation, Figure 4.3 shows the distribution $f(P_1) = dS_1 / dP_1$ for given values of S_2.

Figure 4.3: Frequency distribution of possibilities ($f(P_1) = dS_1 / dP_1$) for given values of S_2



The effect of extra technologies being available is thus to diminish the overall market and the rate of uptake of the others. Any new technology entering the market will change the frequency distributions of possibilities for the others in complex ways, not amenable to an explicit solution.

The finite difference forms such as equation 6 provide a convenient method of solving the equations recursively, without iteration, for the multi-variate (multi-technology) case.

5. Demand and Investment

It is necessary to distinguish between the various energy demand vectors listed above. Later, they will be given a superscript *j*. To reduce notational baggage until it is needed, the superscript will not be used for the time being, and the following equations relate to any particular demand vector.

Let:

- D_t = demand in energy units in year *t*,
- I_t = gross investment, in energy units,
- U_{it} = the working capital stock or capacity in place of technology *i*.
- δ_i = the retirement rate, which often differs between technologies.

Then the gross investment in any year is equal to the amount required to meet the increase in energy demand and replace assets retired in the year:

$$I_t = D_t - D_{t-1} + \sum_i \delta_i U_{it-1} \qquad (8)$$

The capital stock or capacity in place can be obtained for each technology from the recursive relationship that the capital stock in place equals the quantity in place last year less the amount retired plus new investment:

$$U_{it} = U_{it-1} + S_{it-1} \cdot I_{t-1} - \delta_i U_{it-1} \qquad (9)$$

We also need a basis for estimating the upper limit to the shares in new investment, i.e. $\hat{S}_{it}$ in equations 3 to 6. These might arise for example from the amount of intermittent generation that is acceptable on an electrical system without significant storage capacity, or from limits to the amount of land available for biomass projects. There are two approaches. The first is to introduce it through a system of constraints. This was the approach used when developing the equations for the trial runs of the components of the model reported in Sections 4, 9 and 10. The second is to introduce a rising shadow price term into the cost equations as the shares near their upper limits, which is the approach recommended for the full set of equations, discussed in Section 11.

In practice the restriction on investment in a particular technology will not be related directly to its market share in new investment per se, but will stem from technical or resource constraints on its use—e.g. the limits arising from intermittency in the case of wind energy and the availability of land or wastes in the case of biomass. Call this limit $\hat{U}_i$. We need a means of deriving $\hat{S}_{it}$ from $\hat{U}_i$. If the resource constraint is not binding, i.e. *if*

$$\hat{U}_i - U_{it} \geq I_t, \text{ then } \hat{S}_{it} = 1.0 \qquad (10)$$

Here there is no restriction on the share of the technology in new investment. But *if*

$$\hat{U}_i - U_{it} < I_t, \text{ then } \hat{S}_{it} = (\hat{U}_i - U_{it}) / I_t \qquad (11)$$

In this situation $\hat{S}_{it}$ will decline to zero as available options are used up.

6. Cost Dynamics

Since we are dealing with investment choices, the relevant quantities are the present value of the lifetime investment and operating costs of the technology. Alternatively we can use the present worth weighted average of lifetime costs of the investment per unit of capacity (e.g. the average lifetime costs per kW of capacity in the case of electricity) or per unit of energy (e.g. the average lifetime costs per kWh). The following takes the last of these alternatives, since it is the most commonly quoted; it is not difficult to use the others instead if desired. Let $A(n,r)$ be the annuity rate (n = lifetime of the investment, r the discount rate), K_{it} the unit capital costs, f_{it} the unit operating and fuel costs, H_{it} the annual energy output per unit of capacity. The quantity $8760/H_{it}$ is the load or capacity factor.[6] Then the average annual costs per unit of investment $= A(n,r)K_{it} + f_{it}H_{it}$, and the average energy cost per unit of investment, C_{it} is given by:

$$C_{it} = A(n,r)K_{it} / H_{it} + f_{it} \tag{12}$$

Costs are taken to decline with the effects of innovation, learning and scale as investment proceeds. They are calculated using a learning curve formula *modified* to allow for the point that they will be asymptotic to some minimum value $C_{i\min}$. A shortcoming of the standard formula, which has been found to fit well for particular phases of a technology's development, is that it is asymptotically zero, and may lead to over-optimistic assessments of a technology's prospects. Estimates of minimum costs are available from engineering studies; they are inevitably uncertain, and are themselves limited by the engineering concepts used for the projections. However, they do avoid an otherwise implausible assumption, and also allow for the evidence reported by Grubler, Nakicenovic and Victor (1999), that the learning rate may decline in the more mature phases of a technology's development.

The learning effects are related to gross rather than net cumulative investment, i.e. to investment including the experience gained from investments that have been retired. Denoting this quantity by W_{it}:[7]

$$W_{it} = W_{it-1} + S_{it-1} \cdot I_{t-1} \tag{13}$$

Costs in year t equal the costs in the previous period less reductions arising from the 'learning effect' during the period:[8]

$$C_{it} = C_{it-1} - \left(\frac{b_i}{W_{it}}\right)(W_{it} - W_{it-1})(C_{it-1} - C_{i\min}) \tag{14}$$

The learning effect converges to zero as $C_{it} \to C_{i\min}$.

Equation 13 will be amended when the full set of equations is laid out in section 11 below. Most primary energy sources and technologies are capable of meeting the demands of several markets—

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[6] The quantity is most commonly used for electricity, but is relevant for other energy industries.

[7] The W notation is used to reflect world experience, in anticipation of the regional model that is to be developed later. Arnulf Grubler made the point to us, citing several examples which showed that quite a lot of investment does not contribute much to the learning effect since many countries use earlier generations of well-proven technologies. When aggregating world experience, some sort of weighting will need be needed.

[8] The standard learning curve formula is $C_{it} = C_{i0}(W_{it} / W_{i0})^{-b}$, which after differentiating with respect to W_{it} and taking finite differences becomes $C_{it} = C_{it-1} - b_i C_{it-1}(W_{it} - W_{it-1}) / W_{it}$. Equation 14 simply replaces the absolute cost C_{it-1} by $C_{it-1} - C_{i\min}$ such that the asymptotic minimum is $C_{i\min}$.

gas for the markets for gas, electricity and heat for example, and also for hydrogen if that market emerges, renewable energy for electricity and hydrogen, and so forth. Hence the expression for W_{it} needs to be based on the aggregate of investment over all the markets in which the technology is used.

7. Prices, and Lags in the Effects of Policies

The price ratio discussed above is the ratio on which investment decisions are based, while the market shares are the shares that actually obtain when the investments are commissioned. There is of course often an appreciable lag between making an investment decision and the time when it is commissioned—and much uncertainty about whether the cost and price assumptions will hold in the intervening period. An investment in coal, gas or oil may take 5-10 years to realise, in a combined cycle power plant 3 or 4 years, a nuclear plant 10 years, a renewable energy project 2-3 years, and so forth. Let the time lags that are characteristic of a particular technology be denoted by l_i, C_{nt} the costs of the marker technology, T_{it} the tax imposed on the marker technology, and G_{it} the government tax or subsidy for the technology *i*. Then:

$$P_{it} = \frac{C_{nt}}{C_{it}} \cdot \frac{(1+T_{i,t-l_i})}{(1+G_{i,t-l_i})} \qquad (15)$$

This supersedes equation (1) above. There is the question of how to handle the uncertainties in costs and expected prices during the long lead times between a policy announcement, an investment decision and the investment coming into operation. The most straightforward way, perhaps, is to incorporate these uncertainties into the distribution of investment opportunities discussed earlier, in connection with Figure 1. If this is the case, the distribution it depicts is a joint distribution of the cost ratio C_{nt} / C_{it} and the policy uncertainties.

8. Emissions and Accumulations

Several technologies emit more than one pollutant. Let the subscript $k = 1\ldots..K$ denote particular pollutants, and E_{ikt} the emissions from technology *i* and θ_{ikt} emissions per unit output. (That θ_{ikt} differs greatly from one technology to another is the primary reason why substitution has large effects on pollution levels; but for each particular technology θ_{ikt} may also decline over time with marginal improvements, as happened for example with scrubbers, electrostatic precipitators and many pollution control technologies.) Total emissions of *k* in each period are then:

$$E_{kt} = \sum_i \theta_{ikt} \cdot U_{it} \qquad (16)$$

The cumulative net emissions A_{kt} can be estimated from:

$$A_{kt} = (1-r_k)A_{kt-1} + E_{kt} - R_{kt}A_{kt-1} \qquad (17)$$

where r_k and R_{kt} are the natural rate of recovery and remediation rates respectively.

Equation 17 is not to be confused of course with the relationships that define the actual accumulations or concentrations of a pollutant the atmosphere, quantities which can only be estimated from the scientific models of the transport, deposition and decay processes. In the case of climate change, this requires the use of GCM models as part of an integrated assessment exercise. It is simply a measure of net cumulative emissions corresponding to particular assumptions about r_k and R_{kt}.

PART II. THE SPECIAL CASE OF HYDROGEN

This part of the paper presents two short exercises to explore elements of the ‘hydrogen economy’. The use of hydrogen as an energy vector is currently very small in relation to the use of fossil fuels. However, it is worth a short digression to examine two features why many believe it may become ‘the’ energy vector of the future. These are:

- The prospective use of hydrogen for electricity production. The underlying vision is that hydrogen produced by electrolysis from renewable energy would enable the energy from an otherwise ‘intermittent’ resource to be stored for dispatch as and when needed.
- The prospective use of hydrogen in transport. In this case it could be generated either by fossil fuels (with the carbon being sequestered) or by nuclear power or renewable energy, thus allowing a carbon-neutral energy form to enter the transport markets. A further attraction of hydrogen in transport is that if used in a fuel cell vehicle it offers the possibility of significantly increasing the fuel efficiency of the vehicle fleets. (It should be added that the hybrid vehicle offers the same prospect, whether hydrogen or oil fuels are used.)

The production of hydrogen from fossil fuels is well-known to be appreciably less costly than by turning to electrolysis. However, there may be limits to the amount that can be produced imposed by the limits to carbon sequestration. It has been argued that this may be the least cost basis for developing hydrogen infrastructure, opening up the possibilities for the generation of hydrogen from renewable resources later on.

In table 1.1, the column on hydrogen is currently an energy vector in which all elements are very small or zero. The equations used for the exercises below show how the new energy vector is created. Both contain a number of simplifications, which are relaxed in Part III of the report.

9. Hydrogen and Electricity

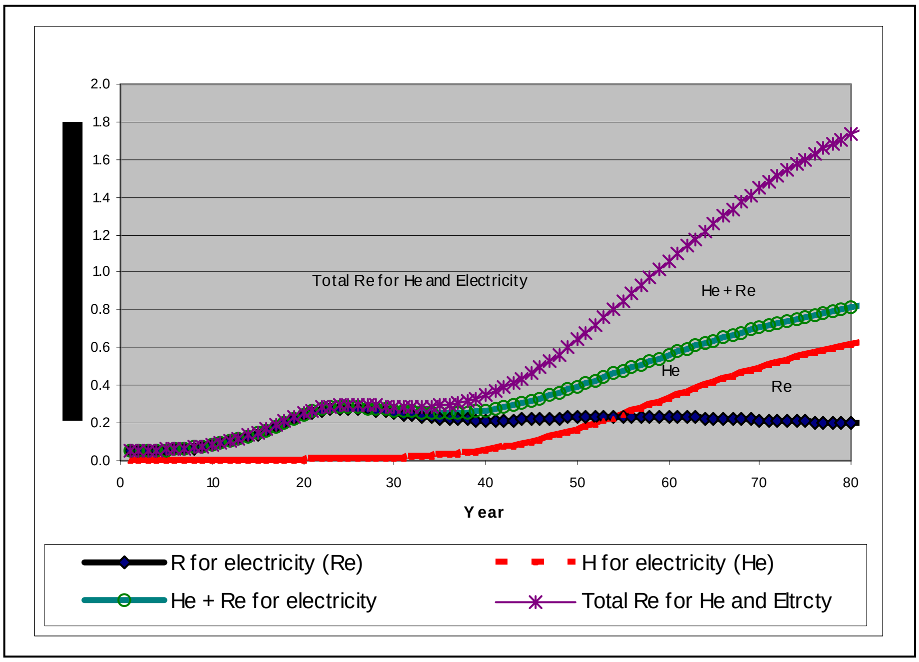
The equations are set out in Appendix 1, and have the following features:

1) An exogenous demand equation for electricity, with steady growth.
2) Annual investment requirements, to meet the annual increase in demand and the retirement of old stock
3) Three substitution equations of the form discussed earlier. The substitutes are
    - Electricity generated by intermittent renewable energy, which is restricted to no more than 25% of total electricity supply.
    - Electricity generated by hydrogen, which in turn is generated by intermittent renewable energy sources at a conversion efficiency of 40%. There is no limit in principle to the amount of energy available from this option.
    - Electricity generated by fossil fuels (the *numeraire*).
4) Cumulative net investment in each of the alternative source of generation.

There are no cost equations in this model; these are considered in Part III. To explore possibilities a steady rate of decline of the prices of renewable energy and of hydrogen of 2% per year relative to the price of fossil fuels is assumed. The initial conditions are 94.9% of demand is met by fossil fuels, 5% from renewable energy, and 0.1% from hydrogen; these correspond to the initial average price of renewable energy being roughly 1.5 times that of using fossil fuels and of hydrogen from renewable energy 3.3 times.

The effect of the steady declines in relative prices is a gradual uptake of renewable energy until the 25% limit is reached; hydrogen production from renewable energy begins to take root sometime later, the lag arising from the higher initial costs of hydrogen; but when it does ‘kick in’, it creates a new intermediate good in the system, as illustrated in Figure 9.1:

Figure 9.1: Electricity Production from Renewable Energy, Fossil Fuels and Hydrogen, with the Hydrogen Produced from Renewable Energy.[A/]



A/ Final Electricity Demand is Normalised to Unity, and all production is expressed relative to this. The curve for fossil fuels is not shown: it 1.0 minus the He + Re curve (shown in green). More electricity is generated than is consumed on account of the losses in converting electricity to hydrogen.

The matrix of inputs and outputs changes as follows; the numbers shown are percentages of the final electricity demand in electricity units; the figures are rounded.

Year 1:

	H	R	F	E
H	-	-	-	0
R	0	-	-	5
F	-	-	-	95
E	-	-	-	-

Year 50:

	H	R	F	E
H	-	-	-	16
R	41	-	-	23
F	-	-	-	61
E	-	-	-	-

Year 80:

	H	R	F	E
H	-	-	-	61
R	153	-	-	20
F	-	-	-	19
E	-	-	-	-

10. Hydrogen and transport

The equations are set out in Appendix 2. This case examines substitution possibilities between hydrogen and fossil fuels in the user (transport) markets, and then the further substitution possibilities between fossil fuels (with carbon sequestration) and renewable energy in the production of hydrogen. The equations have the following features:

1) An exogenous demand for transport fuels, with steady growth.
2) Investment requirements to meet the incremental fuel demands arising from new vehicles and the retirement of old vehicles.

3) Substitution equations to determine the shares in new investments supplied by

   - Hydrogen
   - Oil fuels (the *numeraire*)

4) Cumulative net investment in the production of hydrogen and oil fuels for vehicles

5) An aggregate demand equation for hydrogen derived from (4).

6) Substitution equations to determine the shares in new investments in hydrogen production between:

   - Renewable energy
   - Fossil fuels (the *numeraire*), with sequestration of the CO_2 produced.

Equations to determine relative costs and prices are not studied in this example, and are left to Part III (see section 12.2). To explore options changes in relative prices are fed into the relationships exogenously.

For the transport markets oil fuels are assumed to supply initially 99.99% of the market, the remaining 0.01% being supplied by hydrogen; implicitly this corresponds to the use of hydrogen fuels being 12-15 times more expensive initially than the use of fossil fuels, including vehicle lifetime costs. For the production of hydrogen the *numeraire* could be based on either natural gas or coal-gasification, which also (in this example) initially accounts for 90% of the relatively small quantities of hydrogen produced; electrolysis—which would probably cost three times more—from renewable energy accounts for the remaining 10%. It is assumed that there is a steady decline in the relative costs of the hydrogen fuelled alternative of 3% per year, and in the relative costs of the electrolytic production of hydrogen of 1% per year.[9] Lastly, it is assumed that the fuel-cell vehicle, perhaps the most promising long-term option for hydrogen use in transport, is twice as efficient as the petrol or diesel vehicle.[10]

The results are shown in Figure 10.1. Given the high initial relative costs of using hydrogen it takes some time before the hydrogen option takes root—at least under the assumptions just stated. But once it does there is virtually a 100% switch over a half century period. The hydrogen option would take root much sooner, and the switch would occur more rapidly, under stronger assumptions about changes in relative costs. Ditto the electrolytic production of hydrogen, where there is appreciable potential for technical progress, for example in the area of photo-electrolysis. The fuel-cell efficiency effect is also striking; in practice it is capable of halving the demands of transport for fuel, and the same would apply to hybrid diesel- or petrol-electric vehicles.

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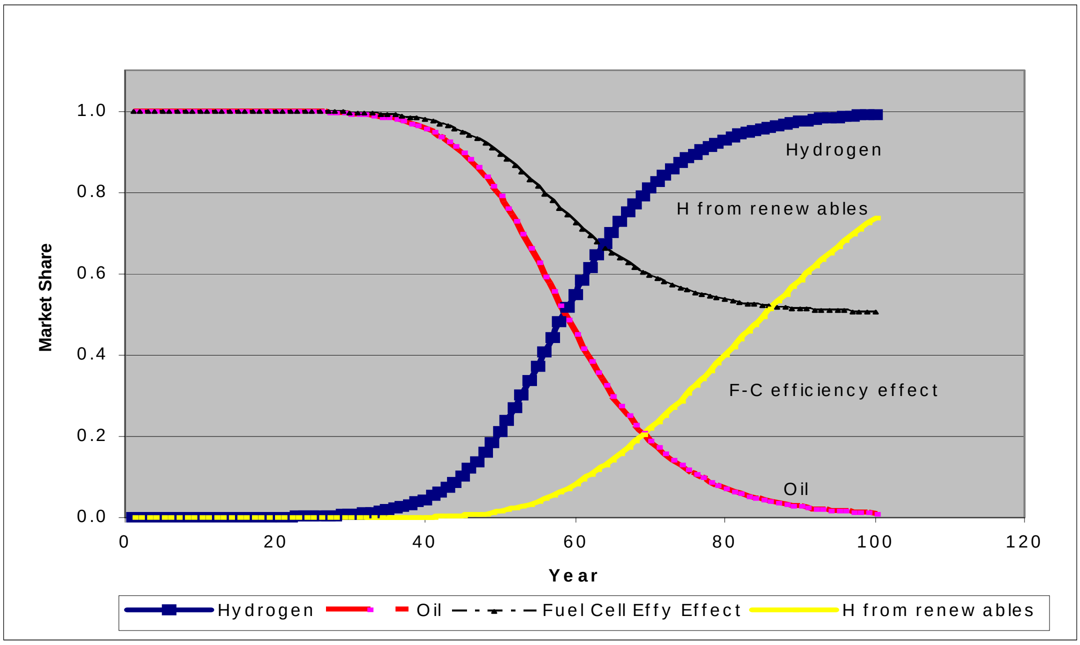
[9] In the full model, the rates of change of relative costs—which are likely to be faster in the early years and slower in the later years—will be determined endogenously from the cost functions discussed earlier.

[10] The hybrid petrol- or diesel-electric vehicle is also capable of doubling efficiency, something we will need to examine in the full E3MG model.

Figure 10.1: Scenario of Hydrogen in Transport with Hydrogen Production from Fossil Fuels or Renewable Energy



The overall effect on the matrix of inputs and outputs is as follows; T stands for transport, H for hydrogen, F for fossil, R for renewables, and the quantities shown are percentages of the total market for transport fuels in energy units; figures are rounded to the nearest percentage point:

Year 1:

	H	**T**
H	-	0
F	0	100
R	0	-
Total		100
F-C effy effect		0

Year 50:

	H	**T**
H	-	21
F	19	79
R	2	-
Total		100
F-C effy effect		-11

Year 80:

	H	**T**
H	-	93
F	53	7
R	40	-
Total		100
F-C effy effect		- 46

Note: F + R for hydrogen production add up to the H for T production. The fuel cell (F-C) effect is counted as a subtraction from the demand that would arise if oil fuels were used for transport.

PART III: A FULL SET OF EQUATIONS

11. Simplification of the Demand Structure

For three of the energy demand categories shown in Table 1.1 above—solid, oil and gas fuels—there is the long-term possibility of hydrogen emerging as substitute. At the same time, these fuels could be significant sources of hydrogen production through a process known as steam reforming.[11] In other words there is the possibility of a demand for new energy vector emerging—hydrogen—which does not yet appear in the demand statistics.

To illustrate the effect Table 11.1 shows the demand and supply structure previously outlined in Table 1.1 but with the hydrogen identified as a separate column in the various energy markets. There are a number of further simplifications adopted to avoid the double counting of substitution effects in the E3MG model. In particular, E3MG already allows for substitution effects between solid fuels, centralised gas supplies[12], oil fuels and electricity and thus are not repeated in the table. An exception is the substitution gas for decentralised forms of CHP, which is included as a new substitute for solid fuels.[13] A few further approximations are discussed below.

Coal, for example is technically a substitute for natural gas, and vice versa; but worldwide the direction of substitution is toward gas, such that the table considers the latter only.

The use of oil fuels for electricity generation is also omitted from the table. They are now mainly used for diesel generators as backup supplies and for small grids in towns and small islands; they account for a declining and small share of generation worldwide. As an approximation the demands met by these sources are grouped in with those met by coal and gas.

The substitutes for traditional biomass are also indicated, though later the implied substitution effects will also be subsumed in other parameters of the model. Specifically, they are likely to be implicit in the estimates of the income elasticities used for calculating the demands for traditional biomass itself, for which the elasticity is negative because biomass for cooking is an inferior good, and the demands for the 'modern' fuels—primarily kerosene and gas—for these purposes rise with per capita incomes.

The possibility of using coal or natural gas to produce hydrogen in a carbon neutral manner is also indicated in the table. Subdivisions of the columns for solid fuels (S), oil fuels (O) and natural gas (G) are used to indicate whether the market in question is being met by hydrogen or the fuel itself.

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[11] The process produces CO_2 and hydrogen; the CO_2 is then sequestered for the enhanced recovery of oil or coal-bed methane, leaving hydrogen as the energy vector in a carbon-neutral cycle.

[12] We also need to discuss the treatment of substitution effects between centralized gas and coal in E3MG, since the substitution elasticities may be high for this—e.g. as revealed in the 'dash for gas' in the 1990s.

[13] Gas fuel cell vehicles are also deleted from the table, along with a number of other approximations, including the production of hydrogen from hydro electricity and biomass crops and wastes, which is likely to be negligible; competition from biomass in the gas markets, with the exception of biomass wastes for CHP, which will compete in the heating markets served by gas; and the import of electricity as a substitute for transport fuels, and the consumption of electricity by power stations, which can be avoided by taking net kWh output.

The marker or *numeraire* technologies are not ticked, but denoted by an asterisk:

Table 11.1: The New Energy Demand-Supply Structure[a/]

Energy Technologies	**Solid Fuels**		**Oil Fuels**		**Natural Gas**		**H_2**	**Electricity**	**Tradl. Biomass**
	S	**H**	**O**	**H**	**G**	**H**			
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Carbon emitting:									
1. Coal—clean	*							y	e/
2. Coal—dirty	y							y	e/
3. Oil fuels—clean			*					-[d/]	*
4. Oil fuels—dirty			y					-[d/]	y
5. Gas—central	y				*			*	y[c/]
6. Gas—micro CHP	y				y			y	
7. Gas—fuel cell vehicle			y						
Carbon neutral:									
8. Nuclear electricity							y	y	
9. Hydro electricity								y	
10. Biomass crops	y		y					y	f/
11. Biomass wastes: CHP	y				y			y	f/
12. Wind—intermittent							y	y	
13. Wind—with storage								y	
14. Solar PV—intermittent							y	y	
15. Solar PV—with storage								y	
16. Solar Thrml—w/gas								y	
17. Solar Thrml—w/storage								y	
18. Solar Thrml--intermittent							y	y	
19. Marine—intermittent							y	y	
20. Marine—with storage								y	
21. Geothermal								y	
22. Coal—with sequestration							*[b/]	y	
23. Gas—with sequestration								y	
24. Hydrogen—central		y				y		y	
25. Hydrogen—micro CHP		y				y		y	
26. Hydrogen—f-c. vehicles				y					

a/ A y indicates where an equation to represent substitution is required, an asterisk the *numeraire*.

b/ Hydrogen from coal or gas (with the carbon being sequestered) is treated as a single option in the present model. The choice between the two primary fuel will probably vary with region in practice. See text section dealing with hydrogen.

c/ In many regions this is LPG, which can be regarded as centrally produced.

d/ Oil fuels are used for electricity generation, but occupy an increasingly small share, and the energy they supply for this purpose is included in with that supplied by coal and gas. (See text.)

e/ Coal was a substitute historically in the industrial countries, and still is in China, but the historical trend is toward kerosene and gas; the use of coal as a substitute is considered to be included in the demands for solid fuels.

f/ CHP from biomass as a substitute for traditional biomass is considered along with coal to be included in the demands for solid fuels.

The notation for the new demand structure of the model is as follows:

1 D_t^s. Solid fuels—with hydrogen as a possible new substitute.
1. D_t^o. Oil fuels—with hydrogen as a possible new substitute.
2. D_t^g. Natural gas—with hydrogen as a possible new substitute.
3. D_t^h. Hydrogen. This is the sum of the demands for hydrogen under 1, 2 and 3.
4. D_t^e. Electricity.
5. D_t^b. Traditional biomass.

The table distinguishes between carbon-emitting and carbon-neutral technologies, since the former include technologies with high and low levels of local pollution. Emissions of PM, carbon monoxide, sulphates, NO_x, unburned hydrocarbons and other local pollutants are orders of magnitude higher in the developing than in the industrial countries because the latter have introduced emission control technologies capable of achieving high levels of abatement; in addition, many are direct GHGs themselves or affect global warming indirectly. The extent to which the 'clean' or 'dirty' technology is used depends on both local and global environmental policies, and are thus made functions of local as well as global policy variables in the following equations.

12. Core Equations for Substitution, Investment, Costs, Prices and Emissions

In the following set of equations a new term is added to reflect the possibility of rising scarcity prices or shadow prices arising from constraints on the use of certain technologies—the amount of intermittent energy that can be permitted on grid systems for example, and the availability of land and wastes for biomass projects. In Part I these issues were dealt with by imposing a constraint on their use. It is perhaps more realistic however to add a rising scarcity or shadow price in the cost equations. This also simplifies the equation structure.

12.1 Solid Fuels

The *numeraire* (denoted by subscript *n*) or market technology is coal without normal emissions controls (often unfortunately called 'dirty' coal). The supply substitutes, denoted by the subscript *i* are:

- 'Clean' coal (row 1)
- Possibly Centralised gas (row 5)
- Gas—micro-CHP (row 6)
- Biomass (rows 9 and 10)
- Hydrogen—central (row 23)
- Hydrogen—micro-CHP (row 24)

Micro-CHP (row 6) is shown in the table as another substitute. However, it is a by-products of electricity production, which raised the problem of how to deal with joint products. Below it is proposed to make electricity the primary product; the quantity of heat produced by micro CHP is denoted by D_{it}^{Echp}. This is deducted from the demand for solid fuels to give a net demand. The benefits are given by the product of D_{it}^{Echp} and the price of solid fuels and are deducted from the costs of the *numeraire* technology (coal), C_{nt}^S, given in equation S14 below, when calculating the net costs of electricity production from CHP in equation E8 below for *i* =CHP.

Substitution equations:

$$S_{it}^{S} = S_{it-1}^{S} + a_i^S S_{it-1}^{S}\left(\hat{S}_{it-1}^{S}(1 + S_{it-1}^{S} - \sum_i S_{it-1}^{S}) - S_{it-1}^{S}\right)\left(P_{it}^{S} - P_{it-1}^{S}\right) \qquad \text{(S1)}$$

Marker technology: $S_{nt}^{S} = 1 - \sum_i S_{it}^{S}$ (S2)

Investment: $I_t^S = D_t^S - D_{t-1}^S + \delta_n U_{nt-1}^S + \sum_i \delta_i U_{it-1}^S$ (S3)

Cumulative net investment: $U_{it}^S = U_{it-1}^S + S_{it-1}^S I_{t-1}^S - \delta_i U_{it-1}^S$ (S4)

Ditto, *numeraire technology*: $U_{nt}^S = U_{nt-1}^S + S_{nt-1}^S I_{t-1}^S - \delta_n U_{nt-1}^S$ (S5)

Cumulative gross investment: $W_{it}^S = W_{it-1}^S + S_{it-1}^S I_{t-1}^S$ (S6)

Ditto, *numeraire technology*: $W_{nt}^S = W_{nt-1}^S + S_{nt-1}^S I_{t-1}^S$ (S7)

Initial cost/unit energy: $C_{i0}^S = f_{i0}^S + AK_{i0}^S / H_i^S$ (S8)

A is the annuity rate. The load factor (hours of use/8760) is assumed not to vary significantly over time.

For *i* = hydrogen (*H*) the value of the variable cost is the same as the price of producing and distributing hydrogen, which is estimated in the equations for hydrogen presented below. The price equals the marginal costs of hydrogen and production, adjusted for taxes and subsidies; it is denoted here by P_t^H :

$$f_{Ht}^S = P_t^H \qquad t = 0, 1, 2\ldots\ldots \qquad \text{(S9)}$$

Initial cost, *numeraire technology*:

$$C_{n0}^S = f_{n0}^S + AK_{n0}^S / H_{n0}^S \qquad \text{(S10)}$$

Cost dynamics of substitute (except hydrogen—see S12 and S13):

$$C_{it}^S = C_{it-1}^S - \frac{b_i^S}{W_{it}^S}\left(W_{it}^S - W_{it-1}^S\right)\left(C_{it-1}^S - C_{i,\min}^S\right) \qquad \text{(S11)}$$

For *i* = hydrogen (subscript *H*) it is necessary to distinguish between technical progress (learning-by-doing) in *using* hydrogen, which mainly applies the capital costs, from technical progress in *producing and distributing* hydrogen, which is determined by the hydrogen supply equations below. Denoting the capital cost term by $k_{Ht}^S = AK_{Ht}^S / H_H^S$, the capital costs of *using* hydrogen is given by:

$$k_{Ht}^S = k_{Ht-1}^S - \frac{b_H^S}{W_{Ht}^S}\left(W_{Ht}^S - W_{Ht-1}^S\right)\left(k_{Ht}^S - k_{Ht-1}^S\right) \qquad \text{(S12)}$$

And the total costs by: $C_{Ht}^S = P_t^H + k_{Ht}^S$ (S13)

Cost dynamics of marker technology:

$$C_{nt}^{S} = C_{nt-1}^{S} - \frac{b_{n}^{S}}{W_{nt}^{S}}\left(W_{nt}^{S} - W_{nt-1}^{S}\right)\left(C_{nt-1}^{S} - C_{n,\min}^{S}\right) \tag{S14}$$

Relative prices:

$$P_{it}^{S} = \frac{C_{nt}^{S}}{C_{it}^{S}} \frac{\left(1 + T_{n,t-l}^{S}\right)\left(1 + M_{n,t-l}^{S}\right)\left(1 + \varepsilon_{t}\right)}{\left(1 + G_{i,t-l}^{S}\right)} \tag{S15}$$

Where $M_{n,t-l}^{S}$ are the local pollution taxes (or imputed taxes) and l it will be recalled is the investment lead time, between the policy and when the investments come into operation; ε_t represents exogenous factors operating on world prices.

Emissions (k = pollutant)

$$E_{kt}^{S} = \theta_{knt}^{S} U_{nt}^{S} + \sum_{i} \theta_{kit}^{S} U_{it}^{S} \tag{S16}$$

The shares of the substitute technologies in the market are subject to the restriction $0 \le S_{it}^{S} \le 1.0$ to avoid chaotic behaviour.

12.2 Oil Fuels

The *numeraire* is a weighted average of ‘clean’ diesel and petrol fuels. The supply substitutes (see Table 2) are:

- ‘Dirty’ oil fuels and technologies—now mostly in developing countries (row 3)
- Biomass crops (row 9)
- Hydrogen fuel cell vehicle (row 25)

Biomass is again the only fuel that will be restricted (because of land requirements). Electricity as a transport fuel will also likely be limited in practice to railways and some niche markets for vehicles.[14]

Equations: These take an identical form to equations S1 to S16 for solid fuels, with an O replacing an S in the superscripts. They are here labelled O1 to O16.

Intitial costs/unit of energy. With practically all new energy technologies these are a function both of the costs of the energy carrier itself and of the technologies that use it. This is especially the case where hydrogen is used, whether for combustion or, even more notably, for the fuel cell vehicle. The relevant cost ratio for analysing the substitution effect is the estimated present value of the lifetime operating and capital costs of (a) oil fuelled vehicles (a weighted average for petrol and diesel vehicles) divided by those of (b) hydrogen fuelled vehicles. The relative prices are then the relative costs of the two technologies adjusted for taxes and subsidies.

For example, if f_{n0}^{O} denotes the initial weighted average costs per unit of fuel consumed by diesel and petrol fuels in the vehicle fleet, H be the average fuel consumption and $A(n,r)K_{n0}^{O}$ the total annualised capital costs, then total costs are $f_{n0}^{O}H + A(n,r)K_{n0}^{O}$, or $f_{n0}^{O} + A(n,r)K_{n0}^{O}/H$ on a per km basis. Using similar notation for the hydrogen vehicles (denoted by subscript h), the initial costs

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[14] The possibilities of an extra-ordinary development in battery technologies are probably best restricted to qualitative analysis. We have no data on what the costs might be.

per km are $f_{h0}^{O} + A(n,r)K_{h0}^{O}/H$. Changes in costs over time will be determined by the cost dynamics discussed earlier, using equations of the form S10 and S11.

Policies in most countries provide differing tax incentives for the development of vehicles and of fuels. In this case the relevant price ratio of using oil fuels relative to hydrogen fuels would be, now denoting the annuity rate simply by *A*:

$$P_h^T = \{ f_{nt}^O (1+x_f) + AK_{nt}^O (1+v_f)/H\} / \{ f_{ht}^O (1+x_h) + AK_{ht}^O (1+v_h)/H\} \qquad \text{(O15)}$$

x and *v* denote fuel and vehicle taxes. They will be the net outcome of several policies—local environmental policies, incentives for innovation, and (in most European countries) global environmental policies.

12.3 Gas

The marker technology is centralised gas supplies. The substitutes are:

- Coal gasification (Row 1) from ‘clean’ coal technologies
- Decentralised heat and power (Row 6) , from gas itself
- Biomass waste gasification and incineration (Row 10), for the heating markets[15]
- Centralised production and distribution of hydrogen (Row 23)
- Decentralised heat and power (micro-CHP), from hydrogen (Row 24).

Again the only technology with technical limitations is biomass. In this case it will be limited by the amount of waste that is produced and can be gasified and/or incinerated.

Equations: These also take the same form as S1 to S16 above, with the superscripts *S* replaced by *G*. They are referred to as equations G1 to G16.

It is possible that the absolute limit to the use of biomass wastes might be related to per capita income, since higher income countries produce more waste. If this is the case, then the upper limit to substitution ($\hat{U}_{Bt}^{G}$) would be time dependent.

12.4 Hydrogen

The initial *numeraire* would be hydrogen from natural fossil fuels with carbon sequestration. The substitute technologies are:

- Nuclear power, using electrolysis (Row 7)
- Wind energy with electrolysis (Row 11)
- Solar PV with electrolysis (Row 13). The frequency distribution of the cost functions here could usefully allow for the possible emergence of photo-electrolysis.
- Solar thermal (Row 17)
- Marine energy (Row 19)
- Coal gasification with carbon sequestration (Row 21)

Hydrogen can also be produced from hydro-electricity using electrolysis, but this would be to replace one already good storage medium by another, which makes neither economic nor engineering sense. It can also be produced using biomass as the heat source, perhaps more cheaply than by the electrolytic processes discussed above. However, as an approximation the possibility is

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[15] Gasification of energy crops is technically feasible but is not modelled, on the assumption that its potential contribution is likely to be small.

ignored in this model since the use of biomass for combustion (perhaps involving gasification as a first step to raise conversion efficiencies) and for liquid fuels would probably be its principal uses. All the renewable energy technologies considered for hydrogen production are intermittent, without storage. Those with storage are considered for electricity production in the next section.

Technical limits to hydrogen production:

- From renewable energy sources it is technically unlimited.
- From nuclear sources, the limits are set by waste disposal and decommissioning issues (a joint constraint on electricity and hydrogen production).
- From coal and gas the limits will be set—possibly at a high level of production—by the amount of CO_2 that can be sequestered for enhanced oil and coal bed methane recovery, or by environmental restrictions on geological sequestration.

Hydrogen Demand: This is estimated endogenously. It is the sum of all the hydrogen demands generated by the hydrogen substitution equations for solid, liquid and gas fuels and electricity. The demand for hydrogen as a substitute in the solid fuel markets for instance is given by cumulative net investment in central and decentralised forms of hydrogen use. Hence, denoting the markets (the columns in Table 2) by *j*:

$$D_t^H = \sum_{\text{For } i,j = \text{hydrogen}} U_{it}^j \qquad \text{(H1)}$$

Referring to table 2 the values of *i* and *j* are thus:

- For the solid fuel markets: hydrogen central and for micro-CHP (*i* = 23,24; *j* = 2)
- For the oil fuel markets: hydrogen-fuel cell vehicle (*i* = 25; *j* = 4)
- For the gas markets: hydrogen central and for micro-CHP (*i* = 23,24; *j* = 6)
- For the electricity markets: hydrogen central and for micro-CHP (*i* = 23,24; *j* = 8)

Substitution equations. It is proposed to treat hydrogen production from gas or coal gasification as a single technological option. In countries with good gas resources, gas will be the favoured option, and in countries with good coal but poor gas resources, coal. Thus rows 21 and 22 in Table 2 are for the moment treated as a single row; at a later stage of the analysis, when a regional model is developed, the aggregate result can be disaggregated by regions based on comparative costs. This approximation simplifies the equation structure considerably.

Hydrogen production from fossil fuels is well known to be the cheapest option in the near and medium term, but there will be the limits as just noted as to how far it might be pursued. It could either be represented by either a binding constraint or a rising shadow price on sequestration. The latter approach is followed below.

Since the marker technology (or *numeraire*) is constrained, it is necessary to change *numeraire* when the constraint imposed on the first one is approached. To deal with this problem a two-step procedure is followed. First, there is a choice between hydrogen production from fossil fuels and from electricity. Second, there is a choice between the various means of producing hydrogen electrolytically.

Using the subscripts *F* and *E* to represent hydrogen from fossil fuels and electrolysis respectively, then the shares of new investment in hydrogen production are given by:

$$S_{it}^H = S_{it-1}^H + a_i^H S_{it-1}^H \left(\hat{S}_{it-1}^H (1 + S_{it-1}^H - \sum\nolimits_i S_{it-1}^H) - S_{it-1}^H\right)\left(P_{it}^H - P_{it-1}^H\right) \qquad \text{(H2)}$$

$$S^H_{Ft} = 1 - S^H_{Et} \tag{H3}$$

Investment: $$I^H_t = D^H_t - D^H_{t-1} + \delta_F U^H_{Ft-1} + \delta_E U^H_{Et-1} \tag{H4}$$

Cumulative net investment in substitute (electrolytic hydrogen):

$$U^H_{Et} = U^H_{Et-1} + S^H_{Et-1} I^H_{t-1} - \delta_E U^H_{Et-1} \tag{H5}$$

Ditto, *H_2 from fossil fuels*: $$U^H_{Ft} = U^H_{Ft-1} + S^H_{Ft-1} I^H_{t-1} - \delta_F U^H_{Ft-1} \tag{H6}$$

Cumulative gross investment: $$W^H_{Et} = W^H_{Et-1} + S^H_{Et-1} I^H_{t-1} \tag{H7}$$

And $$W^H_{Ft} = W^H_{Ft-1} + S^H_{Ft-1} I^H_{t-1} \quad : \tag{H8}$$

Initial cost/unit energy: $$C^H_{E0} = f^H_{E0} + AK^H_{E0} / H^H_E \tag{H9}$$

And $$C^H_{F0} = f^H_{F0} + AK^H_{F0} / H^H_F \tag{H10}$$

Cost dynamics for electrolysis: $$C^H_{Et} = C^H_{Et-1} - \frac{b^H_E}{W^H_{Et}} \left(W^H_{Et} - W^H_{Et-1}\right)\left(C^H_{Et-1} - C^H_{E,\min}\right) \tag{H11}$$

Costs of hydrogen from fossil fuels with carbon sequestration:

$$C^H_{Ft} = C^H_{Ft-1} - \frac{b^H_F}{W^H_{Ft}} \left(W^H_{Ft} - W^H_{Ft-1}\right)\left(C^H_{Ft} - C^H_{Ft-1}\right) \tag{H12}$$

Relative price: $$P^H_{Et} = \frac{C^H_{Ft}}{C^H_{Et}} \frac{\left(1 + T^H_{F,t-l}\right)\left(1 + M^H_{F,t-l}\right)\left(1 + \varepsilon_t\right)}{\left(1 + G^H_{E,t-l}\right)} \tag{H13}$$

The average price of hydrogen for use in the substitution equations in the markets for solid, liquid and gas fuels, and for electricity generation is likely to be set by the minimum of the costs of producing it from the two sources discussed:

Price of hydrogen (for the substitution equations in the markets for solid, gas and liquid fuels and electricity):

$$P^H_t = \text{Min}\,\{C^H_{Ft}\left(1 + T^H_{F,t-l}\right)\left(1 + M^H_{F,t-l}\right)\left(1 + \varepsilon_t\right); C^H_{Et}\left(1 - G^H_{E,t-l}\right)\} \tag{H14}$$

Emissions. All these are local and are associated with hydrogen from fossil fuels:

$$E^H_{Ft} = \theta^H_{kFt} U^H_{Ft} \qquad \text{Pollutants } k = 1 \ldots\ldots K \tag{H15}$$

Shares of renewable and nuclear electricity in the production of hydrogen. Since all will use a common electrolytic technology for hydrogen production, the shares of new investment will probably be determined by their relative costs in producing electricity. The following assume that the shares of the renewable and nuclear energy in hydrogen production equal their relative shares in electricity production, determined by the equations in the next section. This will of course add to their total markets for electricity, and have an effect on their relative costs.

The total investment in fossil fuels for electricity production is given by:

$$\sum_{i=\text{nuclear and renewable energy}} I_t^E S_{it}^E \quad ,$$

with *i* corresponding to columns 7, 11, 13, 15, 18 in Table 2. Hence, recalling that the share of total investment in electrolysis is given by S_{Et}^H, the shares of nuclear and renewable energy in total hydrogen production are given by:

$$S_{it}^H = \frac{I_t^E S_{it}^E}{\sum_i I_t^E S_{it}^E} \cdot S_{Et}^H \qquad \text{(H16)}$$

with *i* again being for nuclear and the various renewable energy technologies used for electrolysis.

A possible surprise is photo-electrolysis. This is not modelled here, but could be considered as being among the low cost solar-hydrogen options, and is a justification for taking a low lower-bound estimate ($C_{E,\min}$) in the cost equation for electrolytic production.

12.5 Electricity

Electricity can be, and in fact is produced on one scale or another by every one of the energy supply technologies listed in Table 1.[16] Some will be restricted for technical reasons, for instance the amount of intermittent renewable energy that can be permitted on the electricity grids, and others for economic reasons, for instance the rising costs of land use by biomass or onshore wind. In the following, these restrictions are represented by a rising cost of use as the limits are reached. The marker technology (*n*) or *numeraire* is electricity generation from natural gas.

Substitution equations:

$$S_{it}^E = S_{it-1}^E + a_i^E S_{it-1}^E \left(\hat{S}_{it-1}^E (1 + S_{it-1}^E - \sum\nolimits_i S_{it-1}^E) - S_{it-1}^E\right)\left(P_{it}^E - P_{it-1}^E\right) \qquad \text{(E1)}$$

Marker technology:

$$S_{nt}^E = 1 - \sum_i S_{it-1}^E \qquad \text{(E2)}$$

Investment:

$$I_t^E = D_t^E - D_{t-1}^E + \delta_n U_{nt-1}^E + \sum\nolimits_i \delta_i U_{it-1}^E \qquad \text{(E3)}$$

Cumulative net investment:

$$U_{it}^E = U_{it-1}^E + S_{it-1}^E I_{t-1}^E - \delta_i U_{it-1}^E \qquad \text{(E4)}$$

Ditto, *marker technology*:

$$U_{nt}^E = U_{nt-1}^E + S_{nt-1}^E I_{t-1}^E - \delta_n U_{nt-1}^E \qquad \text{(E5)}$$

Turning to cumulative gross investment, which is the basis for the cost equations, we need to allow for the production of electricity for the electricity markets, and cumulative gross investment in the markets for electrolysis. Denote the former by W_{it}^{EE} and the latter by W_{it}^{EH}. Then for the electricity markets:

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[16] Including of course fuel cell vehicles, which have seriously been proposed as a source of backup generation for the home. I would suggest we exclude this possibility for the time being.

Cumulative gross investment in electricity production, other than for electrolysis:

$$W_{it}^{EE} = W_{it-1}^{EE} + S_{it-1}^{E} I_{t-1}^{E} \qquad \text{(E6a)}$$

For nuclear energy and intermittent renewable energy technologies there is also the additional investment required to generate hydrogen through electrolysis (i = rows7, 11, 13, 15, 18 in Table 2). For each of these, additional annual investment is equal to the annual investment in hydrogen production $S_{it-1}^{H} I_{t-1}^{H}$ (determined from equation H15), divided by the efficiency of the process, defined here by η_t, such that cumulative gross investment is:

$$W_{it}^{EH} = W_{it-1}^{EH} + S_{it-1}^{H} I_{t-1}^{H} / \eta_t \quad i = 7, 11, 13, 15, 18 \qquad \text{(E6b)}$$

Total gross cumulative investment in substitutes for electricity production:

$$W_{it}^{E} = W_{it}^{EE} + W_{it}^{EH} \qquad \text{(E6)}$$

For those technologies not involved in electrolysis $W_{it}^{EH} = 0$.

Gross cumulative investment, marker technology:

$$W_{nt}^{E} = W_{nt-1}^{E} + S_{nt-1}^{E} I_{t-1}^{E}$$

Initial cost/unit energy. For $i \neq$ hydrogen-based technologies, i.e. excluding those in rows 22 and 23 of Table 2:

$$C_{i0}^{E} = f_{i0}^{E} + AK_{i0}^{E} / H_{i}^{E} \qquad \text{(E7)}$$

And for the hydrogen-based ones (rows 22 and 23):

$$C_{i0}^{E} = P_{0}^{H} + AK_{i0}^{E} / H_{i}^{E} \qquad \text{(E8)}$$

Cost dynamics:

$$C_{it}^{E} = C_{it-1}^{E} - \frac{b_i^E}{W_{it}^{E}} \left(W_{it}^{E} - W_{it-1}^{E}\right)\left(C_{it}^{E} - C_{it-1}^{E}\right) \qquad \text{(E9)}$$

Note: for i = CHP the quantity C_{nt}^{S} times the costs of the marker technology is deducted from this equation, as discussed above.

Relative prices:

$$P_{it}^{E} = \frac{C_{nt}^{E}}{C_{it}^{E}} \frac{\left(1 + T_{n,t-l}^{E}\right)\left(1 + M_{n,t-l}^{E}\right)\left(1 + \varepsilon_t\right)}{\left(1 + G_{i,t-l}^{E}\right)} \qquad \text{(E10)}$$

Where $M_{n,t-l}^{E}$ are the local pollution taxes (or imputed taxes) and l as before is the investment lead time, between the policy and when the investments come into operation; ε_t represents exogenous factors operating on prices.

Emissions (k = pollutant)

$$E_{kt}^{E} = \sum_i \theta_{kit}^{E} U_{it}^{E} \quad (i \text{ includes } n) \qquad \text{(E11)}$$

12.6 Traditional Biomass

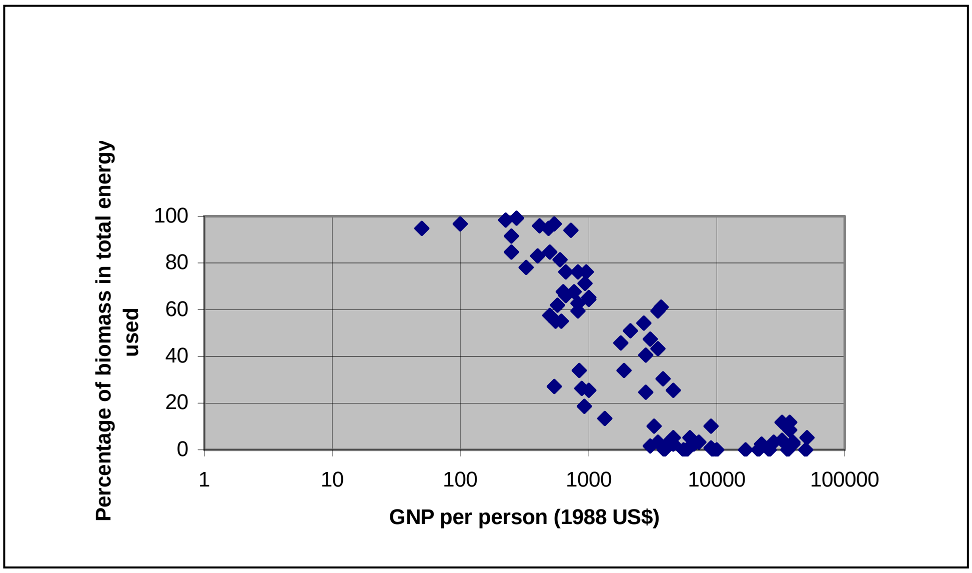
This is a different case, and is almost wholly confined to developing regions. But with 2 billion people dependent on it for cooking, it is an important case. Also, it is associated with unsustainable practices, including land clearance, and though in principle a renewable fuel, is often not renewed, and is a source of both local and global pollution. It requires a different treatment to the one used for the 'modern' energy forms so far discussed.

Beyond an income level that is not far above subsistence levels, its use declines with per capita incomes. This can be seen even in the correlation between average per capita income and biomass use across countries, shown in Figure 7. There are two reasons for this. One is that it is an inferior good—people prefer the appreciable conveniences associated with modern fuels and appliances as incomes rise. Second, the primary component in the private cost of its use is the opportunity cost of labour involved in gathering and cooking with it, which rises directly with the growth of incomes. For these reasons the following simple functional form is proposed for estimating the use of traditional biomass:

$$D_t^b = \alpha (y_t)^{-\gamma} \cdot N_t \cdot \eta_{bt} \qquad \text{(B1)}$$

Where y_t denotes per capita incomes, γ the numerical value of the per capita income elasticity , N_t the population of the regions where biomass use is significant, η_{bt} an efficiency of use term (considerable efforts are made by extension services to improve stove efficiency), and α is a constant. In purchasing power parity terms (figure 1 is based on market exchange rates) a country with a per capita income of $2000 about 90% of energy is from traditional biomass; the substitution to modern fuels is however 90% complete by the time per capita incomes are $10,000, implying a value of γ around 1.4. The efficiency rises from around 3% for open fires, to 10-30% for stoves, to nearly 60% for the use of gas or kerosene. The substitutes people turn to are mainly LPG mainly and oil.[17]

Figure 12.1: The use of biomass as a cooking fuel in relation to GNP per person in eighty countries.



Source: World Bank (1996). *Rural Energy and Economic Development*. Washington DC: World Bank.

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[17] The effects may be implicitly included in the per capita income elasticities for these fuels in E3MG. Further analysis of the E3MG parameters will be needed to establish if this is the case.

Emissions: These are linked directly to biomass use multiplied by an emissions coefficient. Considerable efforts are made to reduce emissions by the extension services, and also by forestry services, e.g. by encouraging the practice of agro-forestry, which among other things makes biomass use renewable. Emissions can be represented by:

$$E_{kt} = \theta_{kt} D_{bt} \qquad \text{(B2)}$$

For sustainable ways of producing biomass, there is the possibility of the CO_2 emissions co-efficient becoming negative, since it would be associated with a greater standing stock of biomass both in trees and shrubs and in soils, since many projects to aim to restore degraded lands, watersheds and woodlands in agricultural areas. At some stage, the costs and benefits of this will also merit re-visiting, since the social benefits are often very high; energy is a by-product.

12.7 Emissions of Methane and Black Carbon

Following the above structure, it is possible to estimate methane and black carbon emissions for each of the above fuels and alternatives. However, obtaining the emission co-efficients is difficult, since they are a function of leakage (in the case of gas and coal mines) and emissions from landfill and other sources; there is still a lot of data gathering to be done. An excellent discussion in a European context is provided in a recent study by IIASA (2004), which has far more detail (for Europe only) than is possible in the present model. It is proposed to link emissions to the use of gas, coal and biomass, using one general set of co-efficients applied to the sum aggregate use of these fuels.

12.7.1 Methane

Methane emissions come from a number of sources including transport, agriculture, biomass burning, landfills, industry, and fossil fuels. There is a good deal of uncertainty regarding the estimation of methane from some of these sources and data are limited. This is concerned with methane emissions from fossil fuels only, specifically from gas and coal.

We use the following relationship:

$$E_t^{methane} = \theta_t^{methane} D_t^{fossil} \qquad \text{(M1)}$$

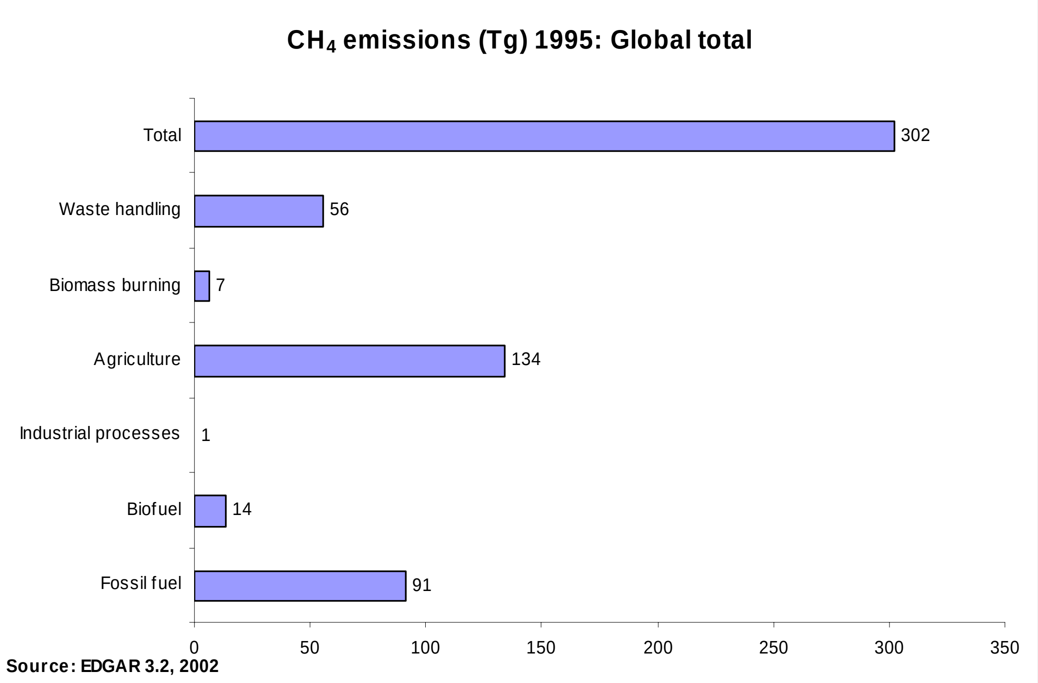
where $\theta_t^{methane}$ is methane emissions per unit output (in g/GJ) and D_t^{fossil} is the demand for fossil fuels in year *t* (in GJ).

The National Institute for Public Health and the Environment (RIVM) has made available a good deal of methane emissions data from the EDGAR database. The following table gives CH_4 emissions for a number of sources for thirteen regions of the world:

Table 12.7.1: CH_4 Emissions (in Tg) in 1995.

CH4		Total	Fossil fuel	Biofuel	Industrial processes	Agriculture	Biomass Burning	Waste handling
	Global total	301.9	91.1	13.9	0.8	134.1	6.5	55.7
	Canada	5.8	2.1	0	0	1	1.5	1.2
	USA	39.8	21.5	0.3	0.1	7.5	0.2	10.3
	OECD Europe	17.4	4.3	0.1	0.1	7.7	0.1	5
	Oceanica	6.3	1.3	0	0	4.2	0.1	0.6
	Japan	2.9	0.8	0	0.1	0.4	0	1.6
	Eastern Europe	8.2	4.7	0.1	0	2.2	0	1.2
	Former USSR	36	24	0.3	0.1	7.8	0.1	3.7
	Latin America	35.1	3.4	0.5	0	21.8	2	7.2
	Africa	26.7	3.5	3.6	0	14.5	1	4.1
	Middle East	9.9	6	0.2	0	2.2	0	1.5
	South Asia	42.3	1.9	4	0	28.2	0.1	8.1
	East Asia	48.2	13.5	2.9	0.2	23.9	0	7.6
	South East Asia	23.3	4	1.8	0	12.7	1.3	3.5

Figure 12.7.1:



Source: EDGAR 3.2, 2002

Using these values, we can obtain an estimate for the parameter $\theta_t^{methane}$ in 1995. It is likely that this parameter will decrease over time due to marginal improvements in the technology. For an initial estimate we can use:

$$\theta_{1995}^{methane} = \frac{91 \times 10^{12}(g)}{150 \times 10^{9}(GJ)} \approx 606 g / GJ \qquad \text{(M2)}$$

where $150 \times 10^9 (GJ)$ (150 Exajoules) is the approximate world energy demand for coal and gas in 1995. Thus we can obtain an estimate for the coefficient for unit methane emissions for fossil fuels. Total demand for fossil fuels can be obtained from the model by adding the demand for fossil fuels across the six fuel sectors, or it could be considered as an exogenous input.

12.7.2 Black Carbon

Data for black carbon emissions are even more difficult to find and more uncertain than data for methane emissions. Most of the emissions appear to come from the use of domestic fuels—coal and biomass—in developing regions, as is evident from the data on China in Table 12.7.2 below. In the following, emissions are linked to the use of biomass and coal in homes.

Data from China are used as a basis, since China accounts for approximately a quarter of global anthropogenic emissions due to its high usage of coal and biofuels (Streets, et al., 1999).

To determine black carbon emissions from coal in year *t*, the following equation is used:

$$E_t^{bc} = \theta_t^{bc} D_t^{totalcoal} (1 - S_t^{cleancoal}) \qquad \text{(BC1)}$$

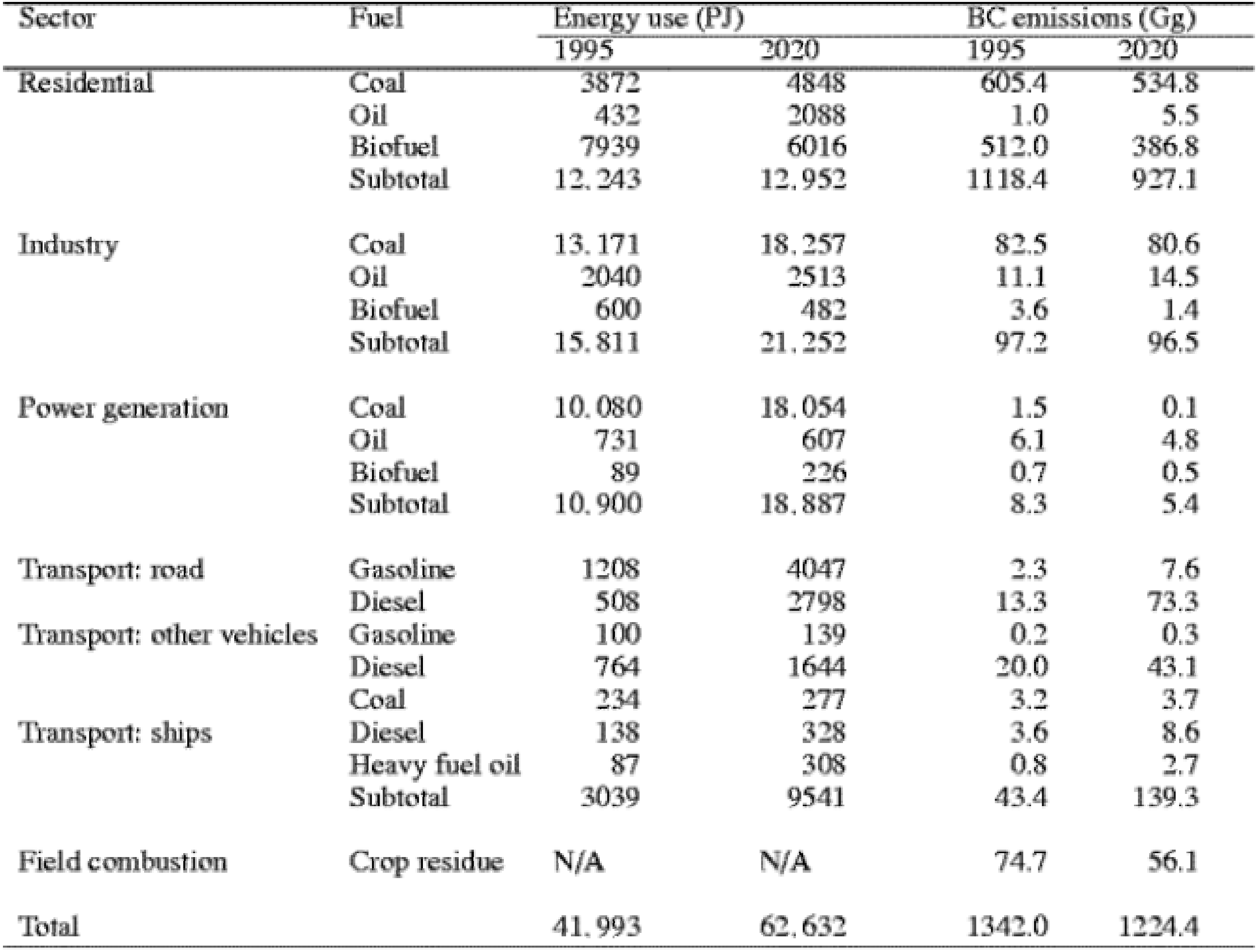
where θ_t^{bc} is black carbon emissions per unit output (in g/GJ) and $D_t^{totalcoal}$ is the total demand for coal in year *t* (in GJ). The term $S_t^{cleancoal}$ is the market shares of clean coal in total coal, which accounts for the use of clean coal which would not contribute to black carbon emissions.

Similarly, we can calculate black carbon emissions from the use of biofuels:

$$E_t^{bc} = \theta_t^{bc} D_t^{biofuel} \qquad \text{(BC2)}$$

where θ_t^{bc} is black carbon emissions per unit output (in g/GJ) and $D_t^{biofuel}$ is the total demand for biofuel in year *t* (in GJ).

Table 12.7.2.: Summary of energy and emission estimates in China by sector and fuel type



Sector	Fuel	Energy use (PJ)		BC emissions (Gg)	
		1995	2020	1995	2020
Residential	Coal	3872	4848	605.4	534.8
	Oil	432	2088	1.0	5.5
	Biofuel	7939	6016	512.0	386.8
	Subtotal	12,243	12,952	1118.4	927.1
Industry	Coal	13,171	18,257	82.5	80.6
	Oil	2040	2513	11.1	14.5
	Biofuel	600	482	3.6	1.4
	Subtotal	15,811	21,252	97.2	96.5
Power generation	Coal	10,080	18,054	1.5	0.1
	Oil	731	607	6.1	4.8
	Biofuel	89	226	0.7	0.5
	Subtotal	10,900	18,887	8.3	5.4
Transport: road	Gasoline	1208	4047	2.3	7.6
	Diesel	508	2798	13.3	73.3
Transport: other vehicles	Gasoline	100	139	0.2	0.3
	Diesel	764	1644	20.0	43.1
	Coal	234	277	3.2	3.7
Transport: ships	Diesel	138	328	3.6	8.6
	Heavy fuel oil	87	308	0.8	2.7
	Subtotal	3039	9541	43.4	139.3
Field combustion	Crop residue	N/A	N/A	74.7	56.1
Total		41,993	62,632	1342.0	1224.4

Source: Streets, et al., 1999

Using values from Table 12.7.2, we can obtain an estimate for the parameter θ_t^{bc} for coal and θ_t^{bc} for biofuel in 1995 for the residential sector:

Dirty Coal:

$$\theta_{1995}^{bc} = \frac{605 \times 10^9 (g)}{3872 \times 10^6 (GJ)} \approx 156 g / GJ \qquad \text{(BC3)}$$

Biofuel:

$$\theta_{1995}^{bc} = \frac{512 \times 10^9 (g)}{7939 \times 10^6 (GJ)} \approx 64.5 g / GJ \qquad \text{(BC4)}$$

Thus we can obtain an estimate for the coefficients for unit black carbon emissions for dirty coal and biofuel in the domestic sector.

13. Parameters and Calibration

We need the following parameters for the five ‘modern’ energy markets plus parameters for the markets for traditional biomass:

Table 13.1: Parameters Required

Characteristic	Units
1. Unit capital costs	US$/kWe
2. Unit coal input	Mtoe or GJ/GWh
3. Unit gas input	Mtoe or GJ/GWh
4. Unit oil input	Mtoe or GJ/GWh
5. Unit CO_2 emissions	kg/kWh or GJ
6. Unit SO_2 emissions	kg/kWh or GJ
7. Unit NOx emissions	kg/kWh or GJ
8. Unit PM10 emissions	kg/kWh or GJ
8. Load factor	ratio
9. Lifetime	years
10. Installation lag	years
11. Development lag	years
12. Learning rate	% or per unit rate
13. Substitution parameter	See substitution equation (sections 2 and 3)
14. Minimum cost	US$/GJ
15. Technical limits	% of total supply
16. Infrastructure costs	US$/GJ
17. Other unit costs (e.g. O&M)	US$/GJ

Parameters differ between regions, sometimes appreciably. This is especially true for renewable energy since resources—wind, tidal, solar and biomass—and the costs of exploiting them vary between countries. The average solar insolation in the tropics is 2.5 times greater than in Western Europe for instance, and it is more evenly distributed throughout the year. Hence the level of regional aggregation will be important. To begin, global averages provided below, along with a comment on how they may differ regionally.

13.1 Energy Units

Except for electricity, for which the energy unit will be kWh, MWh or GWh as appropriate, the energy units will be in Giga Joules (GJ). The units used vary between sources, industry and governments often preferring tonnes of oil equivalent, Btus, therms, and other, but Joules are preferred by scientists. Some conversion factors are[18]:

1.0 tonne of oil ≈ 1.5 tonne of hard coal,
≈ 1110 cubic metres of natural gas,
≈ 10^7 kilocalories, $40\text{x}10^6$ Btus,
≈ 400 therms,
≈ 42 Gigajules (GJ),
≈ $12\text{x}10^3$ kWh
1.0 Gigajoule ≈ 286 kWh

13.2 Treatment of Learning Rates and the Substitution Parameter.

Estimates show that the rates of decline of cost with investment vary over a wide range. The following are estimates compiled by McDonald and Schrattenholzer for selected technologies. The

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[18] Taken from BP’s Statistical Review of World Energy (an annual series).

learning rate is the percentage reduction of costs for each doubling of the cumulative volume of production. For convenience the learning curve parameter (*b*) is also shown[19]:

Table 13.2 Learning Rates for Selected Energy Technologies

Technology (and source of estimate)	**Period**	**Learning Rate, %**	**Para-meter, *b***
Wind:			
- OECD	1981-95	17	0.23
- US	1985-94	32	0.4
- California	1980-94	18	0.24
- Denmark	1990-94	8	0.11
Solar PV:			
- EU	1985-95	32	0.40
- World	1976-92	18	0.18
Ethanol (Brazil)	1979-95	20	0.26
Electrolytic Hydrogen from renewables (engineering studies)	--	18	0.24
Compact Florescent Lamps (US)	1992-98	16	0.21
Gas Turbine Combined Cycle Power Plants:			
- OECD	1984-94	34	0.42
- EU	n.g.	4	0.06
Gas Pipelines:			
- Onshore	1984-97	4	0.06
- Offshore	1984-97	24	0.31
Oil Extraction from the North Sea	n.g.	25	0.32
Coal for Electric Utilities	1948-69	25	0.32
Nuclear Power (OECD)	1975-93	6	0.08
Electric Power Production	1926-70	35	0.43

Source: Except for electrolytic hydrogen, which is based on Ogden's review in the 1999 *Annual Review of Energy and the Environment*, the estimates are quoted from A. McDonald and L. Schrattenholzer (2001), "Learning Rates for Energy Technologies", Energy Policy 29: 255-261, who give estimates for several other technologies and from other sources.
n.g = not given.

The main points are:

- There is much historical evidence in the energy industry to show that costs decline appreciably, and over long periods, with innovation, investment and operating experience.
- The effects are not confined to any particular group of technologies.
- Even for particular technologies, on which substantial experience has already been gained, the estimates show a very wide range.

The 'learning-by-doing' effects are exceedingly important, however, in the early phases of a technology's development. When it occupies (say) around 0.001% to 0.01% of the energy market, even a 100-fold expansion still leaves it occupying only 0.1% to 1% of the market; but experience accumulates rapidly in this period, and costs may decline several-fold. In contrast, when it occupies a larger share, the cost reductions are still significant (as for example with gas-turbine power plant) but are small in comparison. In other words, there can be a phase of rapid catch-up.

In the following tables, there are unavoidably some judgments to be made on which values for the parameter *b*. The general rule followed below is to have high values for the newer and more

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[19] $b = \ln(1+R)/\ln 2$, where R is the learning rate.

modular technologies, in the range 0.2-0.3; intermediate values in the range 0.15-0.2 for the more mature technologies where there is evidence of significant progress; and a low value of 0.1 for the older technologies.

The substitution parameter *a* likewise presents some difficulties, since quite a lot of analysis of the distribution of opportunities is needed for each technology to form a judgment. The rule followed below is to have higher values in the range 10-15 for technologies which are both close substitutes and where we know rapid switching can arise, as between coal and gas for electricity generation; intermediate values in the range 7-10 where the frequency distribution of opportunities is fairly wide (as with wind and biomass across countries, for example), and low values in the range 4-7 where the distributions are very wide, as with solar energy for example.

13.3 Solid Fuel Markets

Coal. The *numeraire* is so-called 'clean coal', by which is meant the use of coal with low sulphur, PM, NOx, fly ash and other emissions except CO_2. Sulphur can be reduced by using low sulphur coals or, like the other emissions, by pollution control technologies at the point of use. 'Clean coal' technologies are in widespread use in the OECD countries, but not in the developing countries. This may help to explain why coal in the OECD is around 1.2 to 1.5 times more expensive than in China and Turkey (though labour costs may be another factor).[20] The average price of coal in OECD was $42/tonne ($1.5/GJ) over the period, in China $29/tonne ($1.0/GJ) and in Turkey $36/tonne ($1.3/GJ).

On this basis we might use c.i.f. costs of $1.5/GJ and $1.3/GJ for clean and dirty coal respectively. This difference is small, suggesting that a relatively small imputed tax on the latter would lead to a sharp substitution toward the former—as has been the case historically. In addition, it is necessary to add to these figures the costs of delivering handling coal. In the UK, the base costs for the Energy White Paper were assumed to be[21]:

- For domestic coal, £5.7/GJ (≈$8/GJ at ppp exchange rates), roughly $6.5/GJ above the world prices.
- Industrial coal, £1.5/GJ ((≈$2.1/GJ at ppp exchange rates), roughly $0.6/GJ above the world price.

Neither will differ much between clean and dirty coal. In addition there are the costs of coal handling in the home (now mainly in developing regions) and in industry. For electricity (considered later) such costs are included in the capital operating costs of the generating plant; however, we have no comparable data readily available for homes and industry. Yet a further factor is the inefficiency of burning coal relative to its substitutes, especially in homes; again, there is little data readily available, since the efficiency differs between appliances—e.g. between open fires, which are highly inefficient, and stoves. Lastly, the E3MG model aggregates domestic and industrial markets, so we need an average for the two. As a starting point, Table 13.2 takes an average of $6.0/GJ and $5.5/GJ for clean and dirty coal respectively.

Natural gas. Prices for households in OECD averaged approximately $360/$10^7$ Kilocalories ($8.6/GJ) over the period 1994-2001, being 3.5 times higher than this in Japan and one half or less than this in countries with good gas resources. For industrial gas, the prices averaged $170/$10^7$ Kilocalories ($4.0/GJ) over the same period being 2.5 times higher in Japan and again going down to half these levels or less in countries with good gas resources. Such variations also arise from the large cost differences between LNG and piped natural gas. As with coal prices there are significant

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[20] Source: *Energy Prices & Taxes – Quarterly Statistics, First Quarter 2003* Part II, Section D Table 16 and Part III Section B, Table 15. Paris: International Energy Agency. The prices are converted to dollars at current exchange rates.

[21] DTI Economics Paper No. 4: *Options for a Low Carbon Future*. June 2003

year to year variations, and a steady upward trend in the 1990s. A mean value of \$6.0/GJ is taken in Table 13.3

Since the E3MG model aggregates all solid fuel markets and doesn't distinguish between LNG and natural gas, the frequency distribution of possibilities is very wide. This means that even with the large differentials between the average costs of coal and gas appreciable markets for both exist, probably most of all for household uses in developing regions, where the imputed costs of coal handling (lighting fires, cleaning grates, etc) are much lower. The standard deviation is taken to be 70% of the mean and the parameter a to be 10.0.

In the industrial countries, gas has displaced many of the markets once held by coal. It is necessary to allow for this in setting the initial conditions of the model, i.e. we need values for S_0. As an approximate basis, we can take the ratios of natural gas to coal in world markets, which is around 0.9:1.0, and make a small deduction for the use of biomass. This is the basis of the figures in Table 2. The split between dirty and clean coal follows the ratio of coal consumption in Central, South and East Asia to that of the rest of the world, which is approximately 50:50.[22]

Micro CHP Using Gas. As discussed in Section 12.1, electricity is considered to be the primary product, such that any heat provided by CHP is simply deducted from the heat (the demand vector) that would be supplied by coal. The benefits of this equal the unit cost of coal times the heat supplied by CHP, and are deducted from the unit costs of electricity from CHP, discussed in Sections 12.1, 12.5 above and in Section 13.5 below. The initial market share corresponds to the sort of market that might emerge from initial demonstration and pre-commercialization projects. (It is necessary to give this a non-zero value to 'kick start' any initiative; it has been deducted from the heat from crops shares, in order to make the shares add up to unity.)

Biomass. The background studies to the Energy White Paper put the costs of using biomass crops at £1.4/GJ (\$2.0/GJ), to which handling and user costs need to be added.[23] These and the costs of maintenance seem to be higher than those of coal, and it has often proved difficult for dedicated crops to compete with coal or gas, except in district heating and CHP plants. Biomass plants also tend to be smaller, with costs in the range \$900-3,000/kW for a CHP plant, varying greatly with location and configuration (UNDP/WEC World Energy Assessment, 2000, chapter 7). This alone would justify a cost in the range of \$4-13/GJ, to which needs to be added the costs of transporting the fuel. A figure of \$8/GJ is assumed in the table and, corresponding to this broad distribution of possibilities, a value for the standard deviation is assumed.

For biomass wastes, the fuel but not the transport and handling would be 'free', and there may be some side benefits, such as the production of less landfill and, in many cases, of fertilizer as a by-product. Using biomass wastes is costed at roughly \$2/GJ less. The development lags would be small as the technologies are familiar.

Emission Rates. The figures for coal are based on the performance of clean coals and clean coal technologies at power stations, divided by 0.4 to allow for the point that power station emissions are based on kWh of output not the kWh of the energy in the coal. (The 0.4 corresponds to 40% efficiency for power stations.) The emissions of PM and NO_x for biomass are assumed to be the same as those for coal. Gas has been treated in a similar manner, except that 50% efficiency is assumed. Micro-CHP has been put equal to gas, except that a higher conversion efficiency of 70% has been assumed. Williams gives the following co-efficients[24]:

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[22] BP *Statistical Review of World Energy*.

[23] Cf the earlier study by Hall, Rosillo-Calle, Williams and Woods (1993) which estimated costs for a number of crops to be in the range \$2.7-3.8/GJ in 1990 declining to \$1.9-2.7/GJ by 2010.

[24] Chapter 8 of the UNDP/WEC World Energy Assessment (2000). New York: UNDP

- For emissions from coal stations using best available technology: 0.46, 0.87, 0.16 and 238 grams per kWh of output for SO_2, NO_x, PM_{10} and Carbon respectively. These need to be converted to the energy of the coal input, which can be done by dividing by 0.45 (the per unit efficiency of the power station). This is done for the estimates in Table 13.3, where the estimates of carbon emissions have been converted to CO_2 units (by multiplying by the ratio of the molecular weight of CO_2 to the atomic weight of carbon (44/12). The energy units are also converted to kg/GJ.
- For gas from combined cycle stations: 0.0, 0.092, 0.0, and 95 grams per kWh of output for SO_2, NO_x, PM_{10} and Carbon respectively. These are divided by 0.5 (the efficiency of the power stations in Williams' data) to convert to the energy units of the gas. Again the carbon is converted to CO_2 equivalent, and all figures are in kg/GJ.

For 'dirty coal', in the absence of country data on the power stations in use, the co-efficients have been multiplied by 20, 10 and 100 respectively for SO_2, NO_x, PM_{10}, corresponding to the estimates reported in Anderson (2001) and the World Bank (1992) of the ratio of the emissions factors for dirty to clean coal technologies. Ideally, we need country-level data on the extent to which emissions controls have been introduced—particularly in China and India.

The 'clean' coal technologies could become yet cleaner. Williams reports[25] that the coefficients for local pollution would be an order of magnitude less for SO_2, NO_x and PM_{10}, being 0.075, 0.082 and 0.0025 grams per kWh of output respectively, using integrated coal-gasification combined-cycle technologies. He we need to assign declining co-efficients for the clean coal technologies.

Emissions from biomass plants emissions of SO_2 and NO_x are assumed to be the same as those for 'clean' coal. There are no net CO_2 emissions if the biomass resource is managed in a carbon neutral way.

Table 13.3: Parameters for Vector of Substitutes for Solid Fuels

Parameter or Quantity	Clean coal	'Dirty' coal	Gas: Central	Gas: Micro-CHP	Biomass:		H
					crops	wastes	
Costs: US$/GJ	6.0	5.5	6.0	j/	8.0	6.0	C^{G}_{Ht} [h/]
Unit CO_2 emissions: kg/GJ[i/]	550	550	75		-	-	0.0
Unit NO_x emissions: kg/GJ [i/]	0.55	5.5	0.05		0.55	0.55	0.55
SO_2 emissions: kg/GJ [i/]	0.29	5.8	-		-	-	0.0
Unit PM_{10} emissions: kg/GJ [i/]	0.1	10.0	-		0.1	0.1	0.0
Lifetime of user plant, yrs	25	25	30		25	25	25
Leadtime for user invstmnts, yrs	5	5	3		4	4	4
Development lag, yrs	0	0	5[d/]		0	0	7[d/]
Substitution parameters: • Stndrd devn: % mean • The parameter '*a*' [c/]	Numeraire	20 10.0	15 12.0		40[f/] 4.0	40[f/] 4.0	20[g/] 10.0
Learning rate	0.15	0.15	0.25		0.2	0.2	0.3
Minimum cost: US$/GJ[j/]	5.0	5.5	4.5		5.0	3.0	C^{G}_{Ht} [h/]
Technical limits: % total market	None	None	None		10%[b/]	10%[b/]	None
Initial market shares (S_0), %[e/]	25	25	45	[e/]	2.5	2.5	[e/]

a/ The heat supplied by CHP is a by-product of electricity production. The parameters are provided in Tables 13.8a and 13.8d.

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[25] Ibid.

b/ Guesstimates at this stage. Biomass will also be used for transport fuels and wastes as a substitute for gas central heating. Crops are limited by land area, and wastes by the amount of waste available.
c/ From Figure 2.3 in text.
d/Allowing for the time to develop the infrastructure.
e/ The initial conditions will be a policy assumption (see text).
f/ .
g/ Similar to hydrogen.
h/ Costs are estimated through the model using the parameters in the hydrogen section, below. C_{Ht}^{G} denotes the cost of hydrogen inclusive of taxes based. The marker technology (hydrogen from coal or gas) will be chosen as a basis.
i/ See text for explanation
j/ The figures in this row are all placeholders for the time being. All technologies continue to show prospects for declines in costs with technical progress, but international factors, in the case of gas, and rising world market demands, could raise prices. In the E3MG model, prices are to be predicted endogenously; in many studies, future prices are analyzed using scenarios.
j/ Heat produced by CHP is a by-product of electricity generation. The benefits (of heat) will be deducted against the costs in the electricity module.

13.4 Oil Fuel Markets

The estimates of parameters are shown in Table 13.5.

Marker technology. 'Clean oil' fuels are the marker technology; these are essentially low sulphur, unleaded fuels with catalytic converters in petrol engines and clean burning diesel fuels. The alternatives are oil fuels without such controls (the vehicles that existed approximately 20 years ago in Europe), the gas-fuel cell vehicle, biomass crops (ethanol) and hydrogen.

'Clean oil' fuels. The costs are based on the Rotterdam spot prices for premium gasoline, presented in BP's Annual Reviews of Energy Statistics. These fluctuate greatly even within a year; e.g. they varied between under \$150/tonne to over \$350/tonne in 1999/00. An average of \$200/tonne is taken, or \$4.7/GJ. To this it is necessary to add the costs of distribution and of pollution controls on cars. The costs of distribution are taken to be 30% of the average spot price (\$60/tonne or \$1.7/GJ), and of pollution controls about 5% of lifetime vehicle capital and operating costs[26], which works out at approximately 25% of the fuel price. On this basis, the costs are taken to be \$4.7 x 1.3 x 1.25 = \$7.6/GJ.

No decline in cost over time is assumed. There has been and continues to be appreciable technical progress in oil exploration, production and refining, but increasingly the international price is determined by a complex combination of price management by OPEC the rising difficulties of oil exploration and production outside OPEC, and the growth of new markets in Asia. If anything, oil prices could rise—a possibility that needs to be explored in the application of the model.

Market shares. It is difficult to estimate market shares precisely because the model aggregates over petrol, diesel, fuel oil and other distillates and residues, and (in the present formulation) across countries. The above price is only a rough indicator, and what is more important is its value *relative* to that of the other fuels. Another difficulty is that practically all—if not all—OECD countries now use what can be termed 'clean fuels', which developing countries are in various initial stages of making the transition. As an approximation, the figures in table 13.3 assume that the, OECD markets use clean fuels and developing countries fuels corresponding to those in use in the OECD two decades ago. This would give a 60:40 split between the two types of fuels. In

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[26] Based on earlier studies with Cavendish (2001) and in the World Bank (1992). Approximately one quarter of the present value of the costs of using a vehicle are on fuel.

addition, some allowance has to be made for bio-ethanol, which accounts for about approximately 5 % of the market for liquid fuels; it is also assumed that 5% of the market for liquid fuels has been taken by electric transport[27]. These lead to the estimates for initial market shares shown in Table 13.3.

Oil fuels without pollution controls. The costs are based on the Rotterdam spot prices for gas oil (about 20% less than those for premium gasoline) plus the same costs as those for premium fuels for distribution. This gives $227/tonne or $5.4/GJ. No decline in cost over time is assumed.

Gas—fuel cell vehicle. The cost of gas is based on the international border price plus transmission and distribution, the latter being on a fairly large scale (e.g. to petrol station outlets). This is taken to be the costs of industrial gas, currently approximately $4/GJ.

In addition, there are the incremental costs of the fuel cell vehicle. The following estimates are taken from Brandon and Hart (1999):

Recent and Projected Costs of Fuel Cell Systems ($/kW)

	AFC	**SPFC-stationary**	**SPFC-transport**	**PAFC**	**MCFC**	**SOFC**
Cost in 1999	2000	8000	550	3000	5000	10,000
Predicted long-term cost	50-100	300	30	1000	600	600

Comment, taken Brandon and Hart:
There are five main classes of fuel cell, each with differing characteristics:

- The Alkaline fuel cell (AFC, with an operating temperature of 60-90°C)
- The Solid Polymer Fuel Cell (SPFC; operating temperature of 80-100°C)
- The Phosphoric Acid Fuel Cell (PAFC; operating temperature of 200°C)
- The Molten Carbonate Fuel Cell (MCFC; operating temperature of 650°C)
- The Solid Oxide Fuel Cell (SOFC; operating temperature of 800-1000°C)

Each has their advantages and disadvantages. The low temperature fuel cells generally incorporate precious metal electrocatalysts, exhibit fast response and short start-up times, are available commercially (AFC, PAFC) or are near commercialisation (SPFC), but require a relatively pure supply of hydrogen, as catalysts can be poisoned by carbon monoxide.

These are all still early demonstration technologies, and would probably be too expensive to enter the market. For example, a vehicle with a 50 kW fuel cell engine costing $550/kW would cost nearly $30,000 for the engine unit alone—ten times that of a petrol engine unit. So we have to assume that some cost target will have been met before commercialization begins. In table 13.5 it is assumed that this cost target is $150/kW (still four times that of a petrol engine). The estimates in Table 13.5 consider a 50kW vehicle and an incremental cost relative to a petrol or diesel engine of $100/kW. The estimates also assume a high learning rate co-efficient and a minimum cost comparable to those of using a petrol vehicle.[28]

For the calculations of relative costs and prices (equations O10 in section 12) it is necessary to convert the co-efficients in table 13.5 to $/GJ. The fuel costs are already in this unit; the capital costs in the same units are given by:

$$\frac{\text{Capital cost (\$/kW) x kW rating x annuity rate}}{\text{Distance per year (km) x litres (of oil equivalent)/km x GJ/litre}}$$

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[27] Figures to be checked with colleagues.
[28] Recall that the additional capital costs are annualised and divided by average annual fuel consumption (see Section 12.2. In addition fuel as well as environmental taxes are added, as in equation O 15.

The units for gas are in oil equivalent units, so to use the estimates in Table 13.5, it we need to know the calorific value of oil in GJ/litre. The value is approximately 0.034 GJ/litre.[29] For a 10 year lifetime and a 10% discount rate the annuity rate is 0.16.

Biomass Crops. The data for biomass are based on the review in the UNDP/WEC World Energy Assessment (chapter 7). Near-term costs for ethanol are quoted as $10-15/GJ (methanol being ($11-13/GJ) and long-term costs as $6-7 ($7-10 for methanol). The potential contribution of biomass to world energy markets is also discussed in this report.

Hydrogen fuel cell vehicle. The costs are taken to be similar to those of the gas-fuel cell vehicle. The development lag is likely to be longer on account of the infrastructure costs. The costs of hydrogen fuels are estimated in Section 13.5 below.

Emissions. Data on vehicle emissions and the technologies for abating them are admirably surveyed by Faiz, Weaver and Walsh (1996).[30] There are difficulties of working from the emission data, however, even when they emerge from road tests, since they differ between urban rural areas and highways, with congestion levels, the quality of vehicle maintenance, vehicle age, vehicle type and a large number of other factors. So finding suitable averages requires far more extensive-a-study than is possible here. Two points can be made however:

First, vehicle emissions have been reduced by orders of magnitude through technical progress in pollution abatement. This can be seen from the following data for US vehicles:

Table 13.4: Progression of US Exhaust Emission Standards for Light-Duty Gasoline-Fuelled Vehicles (grams per km).

Model Year	Carbon Monoxide	Unburned Hydrocarbons	Nitrogen Oxides
Pre-1968 (uncontrolled)	56.0	9.4	3.9
1970	21.0	2.6	-
1975-76	9.4	0.9	1.9
1980	5.9	0.26	1.2
1994-96	2.1	0.15	0.2
2004 (projected)	1.1	0.08	0.12

Data on PM emissions are spotty, but do seem to have come down by similar orders. Faiz et al report PM emissions in the range 0.2-0.4 grams per km for European diesel cars for the mid 1990s, and 0.01 grams per km for petrol vehicles, an average (say) of around 0.1. For earlier periods the emissions are probably correlated with the levels of carbon monoxide and unburned hydrocarbons: all are a function of poor maintenance and incomplete combustion as much as the absence of a technology to control pollution.

Emissions in grams per km for diesel engines are also highly variable, but seem to be of the same order. The following is one set of data tabulated by Faiz et al for diesel cars urban areas in Europe (1993data):

	Without Catalyst	With Catalyst
Carbon monoxide	1.30	0.05
Unburned hydrocarbons	0.08	0.10
Nitrogen oxides	0.70	0.90
PM	0.20	0.30

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[29] There are approximately 1.35 kilolitres to a tonne of gasoline and 1.19 kilolitres to a tonne of diesel fuel. The above takes an average of 1.25 kilolitres/tonne and 42 GJ/tonne.

[30] Air Pollution from Motor Vehicles: Standards and Technologies for Controlling Emissions. Washington DC: The World Bank.

Data for developing countries are sparse, but are probably orders of magnitude higher, corresponding to emission levels in the OECD before emission controls began in the early 1970s.

On this basis:

- PM emissions for the ‘dirty’ or polluting case are put at 1.0 grams per km and 0.01 grams per km for the clean fuels case (except for gas and hydrogen, where they are nearly zero).
- NO_x emissions: 4.0 and 0.5 grams per km for dirty and clean fuel technologies respectively.
- Unburned hydrocarbons: 10.0 and 0.1 grams per km for dirty and clean fuel technologies respectively.
- CO_2 emissions can be calculated directly from the fuel consumption. 1 litre of oil fuels is approximately 860 grams, which would correspond to an emission level 860 x 44/14 = 2703 grams of CO_2 per litre with complete combustion. Hence for a fuel consumption rate of 1 litre per 10 km, this would give 270 grams of CO_2 per km, which is similar to the estimates reported by Faiz et al for vehicles with this fuel consumption rate. For earlier vehicles (with less complete combustion), their figure is 250 grams per km.

The emissions data are given in Table 13.5. The factor to convert from emissions in grams per km to grams per GJ is given by:

$$\frac{\text{Emissions in grams/km x Fuel consumption rate in km/litre}}{\text{0.034 GJ/litre (the calorific value of fuel)}}$$

This leads to the estimates provided in table 13.5.

For biofuels, the assumptions are (a) that the crop is CO_2 neutral, aside from the energy used in producing the crop; this is allowed for in the E3MG model through the input-output matrix, which calculates intermediate inputs and their energy requirements, and (b) that other emissions are similar to those of the ‘clean’ oil fuel technologies.

Substitution Parameters. Experience with the transition to unleaded fuels and the use of catalytic converters in the 1980s and 1990s shows that the rates of substitution can be very high when relative prices are close. On the other, low rates of substitution are likely when relative prices are far apart. For these reasons a ‘sharp’ substitution parameter is suggested for vehicle fuel technologies. (See table 13.3.)

Table 13.5: Parameters for Vector of Substitutes for Oil Fuels

Parameter or Quantity	Clean oil	'Dirty' oil	Gas: Fuel cell vehicle	Biomass Crops	Hydrogen: Fuel cell vehicle
Initial Costs:					
• Variable US$/GJ [a]	7.6	5.4	4.0	12.0	C_{Ht}^{G} [e]
• Fixed US$/kW[b]	-	-	100	-	100
• Average US$/GJ	7.6	5.4	50.0	12.0	C_{Ht}^{G} + 50
Average consumption: km/litre	10.0	10.0	20.0	10.0	20.0
Unit CO_2 emissions: g/GJ	80,000	74,000	40,000	0.0	0.0
Unit NO_x emissions: g/GJ	150	1175	0.0	150	0.0
Unburned hydro carbons: g/GJ	30.0	2950	0.0	30.0	0.0
Unit PM emissions: g/GJ	3.0	295	0.0	3.0	0.0
Lifetime of vehicle, yrs	10	10	10	10	10
Leadtime for user invstmnts, yrs	1	1	1	1	1
Development lag, yrs	1	1	10	5	15
Substitution parameters:					
• Stndrd dvn: % mean	Numeraire	15	15	20	15
• The parameter '*a*'		15.0	15.0	10.0	15.0
Learning rate	0.0	0.0	0.35	0.25	0.35
Minimum cost: US$/GJ	7.6	5.4	7.5	7.0	7.5
Technical limits: % total market	None	None	80%[c]	10%[d]	80% [c]
Initial market shares (S_0), %	54.0	36.0	f/	2.0	f/

a/ Before excise taxes. All incremental capital costs for liquid fuels—e.g. of catalytic converters—are annualized, divided by annual fuel consumption and included in the variable fuel price. For the fuel cell vehicle the incremental capital costs are treated differently (see b).

b/ This is the *incremental* capital cost (see text). The average unit size of the vehicle engine is taken to be 50kW and distance travelled 10,000km/year.

c/ Will be limited to the vehicle fuel markets, i.e. excluding shipping and aviation. Biofuels, on the other hand, could be well suited for these markets.

d/ Based on the assessments of Shell, the World Energy Council and other, reported in Chapter 7 of UNDP/WEC (2000) World Energy Assessment. New York: UNDP. Estimates of the contribution of biomass range from 114 Exajoules (EJ) per year to 325 EJ, as compared with today's total energy demand of around 400 EJ and prospectively twice or more this level in two generations' time. A significant fraction of biofuels may also of course be used for CHP.

e/ Costs are estimated through the model using the parameters for the hydrogen section, below. C_{Ht}^{G} denotes the cost of hydrogen inclusive of taxes based. The marker technology (hydrogen from coal or gas) will be chosen as a basis.

f/ The initial market shares will be a policy variable for the new technologies—the size of the market used to demonstrate the technology. The technology will have to go through a significant development phase, even allowing for RD&D over the past 10-15 years, before the incentives applied to the initial conditions kick in.

13.5 Natural Gas

Parameter estimates are shown in Table 13.6. Centrally supplied gas is the *numeraire*. The substitutes are gas for CHP, biomass wastes for CHP, the centralized production of hydrogen, and hydrogen for CHP.

Central supplies of natural gas. For costs, a mean value of \$6.0/GJ is taken, as in Table 13.3. All other parameters are also the same.

Biomass wastes. Similar to Table 13.3. The initial market share reflects use of biomass for heat production (e.g. from agricultural and municipal wastes) around the world. The figures are quite uncertain since statistics are not routinely gathered as they are for oil, gas and coal. Biomass will also be used for transport fuels and wastes as a substitute for heat from coal. Wastes are limited by the amount of waste societies produce. Limits to biomass use are often institutional not technical. The technical limit could be much larger—around twice the 5% limit shown in Table 13.6—if environmental objections were relaxed. See Hall and Rossillo-Caille (1998), who estimate that current world consumption of biomass is around 45 (+ or – 10) Exajoules (EJ) but is prospectively in the range 90-280EJ. Of the 50 EJ used today, roughly 38 (+ or – 10) EJ is 'traditional' and the balance (≈ 7EJ, or 1.7% of world energy consumption[31]) for commercial EJ (UNDP/WEC 2000, chapter 7).

Micro CHP Using Gas. As discussed in Sections 12.1 and 13.1 above, electricity is considered to be the primary product, such that any heat provided by CHP from natural gas is deducted from the heat (the demand vector) that would be supplied by gas. The benefits of this equal the unit cost of coal times the heat supplied by CHP, and are deducted from the unit costs of electricity from CHP, discussed in Sections 12.1, 12.5 above and in Section 13.5 below.

Central Hydrogen and CHP from Hydrogen: As for Table 13.3.

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[31] Total world energy consumption is currently approaching 400 EJ per year.

Table 13.6: Parameters for Vector of Substitutes for Natural Gas

Parameter or Quantity	Gas: Central	Biomass wastes	Central hydrogen	Gas: Micro-CHP	Hydrogen: Micro-CHP
Costs: US$/GJ	6.0	6.0	C_{Ht}^{G} [a/]	c/	c/
Unit CO_2 emissions: kg/GJ	75	0.0 [g/]	0.0		
Unit NO_x emissions: kg/GJ [f/]	0.05	0.55	0.0		
SO_2 emissions: kg/GJ	0.0	0.0	0.0		
Unit PM emissions: kg/GJ [f/]	0.0	0.1	0.0		
Lifetime of user plant, yrs	30	25	25		
Leadtime for user invstmnts, yrs	3	4	4		
Development lag, yrs	5[d/]	0	10[d/]		
Substitution parameters: • Stndrd devn: % mean • The parameter '*a*'	*Numeraire*	 50 15.0	 70 10.0		
Learning rate	0.25	0.2	0.3		
Minimum cost: US$/GJ	4.5	3.0	C_{Ht}^{G} [a/]		
Technical limits: % total market	None	10.0[b/]	None		
Initial market shares (S_0), %[e/]	95	2.0 [b/]	e/	e/	e/

a/ Costs are estimated through the model using the parameters in the hydrogen section, below. C_{Ht}^{G} denotes the cost of hydrogen inclusive of taxes based. The marker technology (hydrogen from coal or gas) will be chosen as a basis.
b/ Only rough estimates at this stage.
c/ Heat supplied by CHP is a by-product of electricity production. The parameters are provided in Tables 13.8a and 13.8d.
d/ Allowing for the time to develop the infrastructure.
e/ As with the other energy vectors, the initial conditions for the demonstration phase are an exogenous policy variable. Recall this is the share in the market for new investment, whereas the total limit relates to the share in cumulative investment.
f/ Emissions parameters for biomass and gas assumed to be same as in table 13.3
g/ If used on a carbon-neutral basis

13.6 Hydrogen Production

The alternatives for hydrogen production are electrolytic production from nuclear power, wind, marine or solar energy, and direct production from natural gas or coal with (with the climate change uses of the E3MG model in mind) carbon sequestration. Biomass can also be used to produce hydrogen and, currently, more cheaply than its production from electrolytic uses. However, the principal purpose of producing hydrogen from renewable sources is to produce a means of storage; biomass, of course, already is a stored form of energy. The argument is sometimes made that hydrogen production from biomass with the carbon being sequestered, would actually lead to negative CO2 emissions; this possibility is ignored in this formulation.

Some background information on hydrogen production, storage and use is provided in Appendix 5: it is taken from a report for the Carbon Trust by Imperial College's Centre for Energy Policy and Technology, and is copied here because it contains useful background information and underwent a detailed peer review by industry and government sources.

Hydrogen production from coal and gas. This is the cheapest means of producing hydrogen, and is chosen as the *numeraire*. For the reasons noted earlier (see footnote *b* to Table 11.1), hydrogen production from either or both of these source is treated as one option, largely because for countries with good coal resources (China and India for example) coal would be the preferred option, while for countries with good gas resources, gas would be preferred; without a level of regional disaggregation that is beyond the scope of this model, it would be very difficult to distinguish between the two cases.

A review of the methods and costs for producing, compressing, storing and distributing hydrogen is provided by Ogden (1999)[32]. She shows that there are appreciable scale economies in its production from coal and gas. With natural gas as the feedstock her estimates are as follows (figures rounded):

Size of plant (million scf of H_2/day)	**Production cost ($/GJ)**
0.1	26.0
1.0	10.0
10.0	5.0
100.0	4.0

These are based on natural gas costs of $3-4/GJ, as compared with the more recent figure suggested above of $6/GJ (table 13.5). The costs from coal can be higher since coal needs to be gasified first; on the other hand, the costs of coal itself are lower, around $1.5/GJ (table 13.2). To these estimates it is necessary to add the costs of compression, storage and bulk transmission. Ogden estimates that the costs of compression and underground storage (already a common practice) to be in the range $2-6/GJ; bulk transmission costs seem to be quite low, around $0.3-0.4/GJ per 100 km (figures rounded), though some estimates are less than half of this. Lastly, there are the costs of compressing and transmitting the CO_2 to a suitable location for sequestration. These seem to be small in relation to the initial costs (just indicated) of separating the carbon from the feedstock through steam reforming[33], since the process already produces a pure stream of CO_2 and the transmission costs are probably less than those for hydrogen; in addition, for a significant period, the CO_2 would be used for enhanced oil or coal bed methane recovery on a carbon neutral cycle, which would more than recover the extra costs.

Overall a figure of $15/GJ of hydrogen produced, compressed, stored and transmitted in bulk from natural gas or coal seems a reasonable a basis. This is similar to the estimates used for the UK Energy White Paper, based on the conclusions of a workshop of specialists from industry[34], and for the present analysis it would also include the sequestration of CO_2. The lower bounds estimate (once the technology is mature) is taken to be $10/GJ (slightly less than twice the costs of natural gas).

Electrolytic production of hydrogen: the components of costs. There are three components of costs: the cost of electricity, of electrolysis, and of compression, storage and transmission. The costs of electricity will be dealt with in the next section.

The costs of electrolysers are $500-600/kW rating, with projected costs for large scale production of $300/kW. Taking an initial figure of $600/kW, an annuity rate of 10%, a utilization rate of 6000

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[32] "Prospects for Building a Hydrogen Energy Infrastructure", *Annual Review of Energy and the Environment*, 24:227-79.

[33] See the analysis of Williams in Chapter 8, table 8.10 of the World Energy Assessment, cited above. He works with a CO_2 disposal cost of $5/tonne of CO_2 , which is barely $0.1/GJ. Ogden likewise comments: "studies carried out by the European community indicated that the cost of CO_2 pipeline over several hundred kilometres to an underground injection site would add <$1/GJ to the cost of co-produced hydrogen. The cost of injecting CO_2 into a deep saline aquifer or depleted gas field is likely to be an order of magnitude lower than transmission costs."

[34] DTI Economics Paper No. 4, cited above, Annex D.

hours of per year (70% load factor), and a conversion efficiency of 80% efficiency, the net cost would be (600 x 0.1)/(6000 x 0.8) = \$3.6/GJ. For compression, storage and transmission, the average cost of \$4/GJ (the average of those quoted by Ogden for the compression, storage and transmission of hydrogen from gas), giving an overall initial figure of ≈ \$8/GJ. The minimum costs would probably be ≈ \$5/GJ, assuming with Ogden that electrolyser costs could be halved. (See also Appendix 5.)

The initial costs of electricity and their changes over time will be determined from the equations for electricity production in the next section. The main energy sources are hydrogen from the following five technologies (the notation for the costs of electricity from these technologies, inclusive of taxes, are shown in parentheses):

- Nuclear power. (Costs plus taxes = $C_{Nt}^{EG} = C_{Nt}^{E}(1+T_{Nt})$.)
- Intermittent wind. (Costs plus taxes = $C_{Wt}^{EG} = C_{Wt}^{E}(1+T_{Wt})$)
- Intermittent solar energy: PVs. (Costs plus taxes = $C_{Pt}^{EG} = C_{Pt}^{E}(1+T_{Pt})$)
- Intermittent solar energy: solar thermal. (Costs plus taxes = $C_{STt}^{EG} = C_{STt}^{E}(1+T_{STt})$)
- Intermittent marine energy. (Costs plus taxes = $C_{Mt}^{EG} = C_{Mt}^{E}(1+T_{Mt})$)

The minimum costs for the technologies are assumed to be 4, 3, 5, 4 and 5 US cents per kWh (12, 9, 15, 12, and 15 dollars per GJ) or respectively, plus the long term taxes (or less the long term subsidies), based on the World Energy Assessment (Table 4, p 15 and Chapters 8 and 11).

Table 13.7: Parameters for Vector of Substitutes for Hydrogen Production

Parameter or Quantity	**Coal or Gas**	**Nuclear**	**Wind**	**Photo-voltaics**	**Solar thermal**	**Marine**
Costs: US\$/GJ	15.0	$8 + C_{Nt}^{EG}$	$8 + C_{Nt}^{E}$	$8 + C_{Pt}^{EG}$	$8 + C_{STt}^{EG}$	$8 + C_{Mt}^{EG}$
Unit CO_2 emissions: kg/GJ	0.0	0.0	0.0	0.0	0.0	0.0
Unit NO_x emissions: kg/GJ	0.05 a/	0.0	0.0	0.0	0.0	0.0
SO_2 emissions: kg/GJ	0.0 a/	0.0	0.0	0.0	0.0	0.0
Unit PM emissions: kg/GJ	0.0 a/	0.0	0.0	0.0	0.0	0.0
Lifetime of user plant, yrs	25	40	25	25	25	20
Leadtime for user invstmnts, yrs	5	7	2	1	2	2
Development lag, yrs	5	10	10	10	10	10
Substitution parameters: • Stndrd devn: % mean • The parameter '*a*' d/	 *Numeraire*	 30 7.0	 30 7.0	 30 7.0	 30 7.0	 30 7.0
Learning rate	0.2					
Minimum cost: US\$/GJ	10.0	5.0 + $C_{N\infty}^{EG}$	5.0 + $C_{N\infty}^{E}$	5.0 + $C_{P\infty}^{EG}$	5.0 + $C_{ST\infty}^{EG}$	5.0+ $C_{M\infty}^{EG}$
Technical limits: % total market	None	None	None	None	None	None
Initial market shares (S_0), %	100 c/	b/	b/	b/	b/	b/

a/ Same as for natural gas

b/ Recall the initial market is small and is likely to be dominated initially by hydrogen from gas or coal. The initial market share will be determined by the level of demonstration effort—a policy

variable—and the effects on substitution will not kick in until the development phase, which as indicated would likely be a long one, is over.
c/ *Less* the initial market shares for the other technologies.
d/ The substitution possibilities among these options are likely to vary greatly between regions, such that a fairly large standard deviation and a low value of the substitution parameter is chosen, as indicated in the table.

13.7 Electricity

All available fuels and technologies can be used to generate electricity. Table 11.1, which itself could be disaggregated further, lists four carbon emitting options—coal (‘clean’ and ‘dirty’), oil (ditto), centralized gas supplies for large power stations, and gas for micro-CHP—and eighteen carbon neutral ones. The parameters for these are presented in four tables:

- Table 13.8a: fossil fuel, nuclear and hydro alternatives
- Table 13.8b: biomass, wind (intermittent and with storage), and solar PV (intermittent and with storage)
- Table 13.8c: solar thermal (with and without storage), marine (with and without storage) and Geothermal
- Table 13.8d: Coal and Gas, with sequestration; Hydrogen, centrally produced; and Hydrogen for micro-CHP.

The explanations for the data and assumptions are provided in the footnotes.

Natural gas combined cycle power plant is the *numeraire*.

Table 13.8a: Parameters for Vector of Substitutes for Electricity: Fossil Fuel, Nuclear and Hydro Alternatives

Parameter or Quantity	Gas: central	Gas: Micro-CHP	'Clean' coal	'Dirty' coal	Nuclear	Hydro
Initial Costs:[a/] - Variable UScents/kWhe - Fixed US$/kW[b/] - Average UScents/kWhe[c/]	 2.2 450 3.0	 2.6 – 2.0[g/] 2200[h/] 4.0	 1.8 1200 3.6	 1.8 1000 3.3	 1.1[i/] 2200 4.4	 0.0 1500[k/] 3.5
Efficiency, kWhe/kWh of fuel%	55%	50%	40	40	-	-
Load factor, %[d/]	80	50[f/]	80	80	80	50
Waste heat utilized, % of kWh of fuel input[e/]		25%	-	-	-	-
Unit CO_2 emissions: g/kWh[m/]	350	350	870	870	0.0	0.0
Unit NO_x emissions: g/kWh[m/]	0.09	0.09	0.9	9.0	0.0	0.0
SO_2 emissions g/kWh[m/]	0.0	0.0	0.5	10.0	0.0	0.0
PM_{10} emissions: g/kWh[m/]	0.0	0.0	0.16	16.0	0.0	0.0
Lifetime of plant, yrs	25	25	30	30	30	40
Leadtime for investment, yrs	4	1	5	5	7	6
Development lag, yrs	1	10	1	1	3	1
Substitution parameters: - Stndrd dvn: % mean - The parameter '*a*'	 Numer-aire	 0.3 6.0	 0.2 10.0	 0.2 10.0	 0.2 10.0	 0.4 4.0
Learning rate	0.25	0.35	0.2	0.2	0.1	0.1
Minimum cost: US$/kWhe	3.0	2.5[l/]	3.0	2.7	3.5	3.5
Technical limits: % total market	None	None	None	None	75%[j/]	10%
Initial market shares (S_0), %[n/]	18	o/	24	20	17	17

All costs derived from UK data are converted to $ at a ppp rate of $1.55/£

a/ Expressed in power and energy units per kW and kWh, since these are the most familiar quantities. To convert the latter to $/GJ multiply by 286 kWh/GJ. Cost estimates are available in the DTI report cited above, and in various chapters of the UNDP-WEC World Energy Assessment. (The two sources are surprisingly comparable.) The costs of nuclear power are also reviewed in the MIT study:

b/ Includes the capitalized value of the annual fixed costs of maintenance, which is usually expressed as a percentage of the capital cost.

c/ Using a 10% discount rate.

d/ Used for calculating the average cost per kWh shown above.

e/ Applied to micro-CHP only for the technologies in this table.

f/ For individual units, Hawkes and Leach (2004) find that load factors are quite low. This relatively high load factor for small units assumes some export of the surplus power back to the grid, encouraged, for example, by net metering.

g/ Includes the costs of distribution of gas to household and commercial users of micro-CHP, minus 0.3 (the heat provided per unit of kWh electrical output) times the value of heat, which is taken to be the costs per GJ from gas or coal (see tables 13.3 and 13.6).

h/ These are the capital costs of approximately $3000/kW minus the savings in the costs of investment in electricity distribution, which are put at $1000/kW. Fixed maintenance is assumed to amount to 10% of the annuitised capital cost (about $25/kW/year). For further discussion, see Anderson and Leach (2004).

i/ Variable operating costs.

j/ Nuclear power would be confined to base load generation, as it does not have the operating flexibility to meet variable loads.

k/ Hydro costs are highly variable with site. This is reflected in a high s.d. for the substitution parameter.

l/ This implies the capital cost savings on electricity distribution would exceed the capital costs of a micro CHP unit were to decline below, which is thought to be possible. (The costs of electricity distribution are around $1000/kW.)

m/ these are as for Table 13.2, but converted to grams/kWhe, after dividing by 286kWh/GJ and the efficiency of the generator.

n/ Source: IEA (2004) Key World Energy Statistics (2003). Paris: IEA. The figures are for 2001. Oil fuels account for 7% but a rapidly declining share (it was 25% in 1971); as discussed in the text, it share has been divided between clean and dirty coal.

o/ As in other tables involving CHP, the initial conditions for the demonstration phase are an exogenous policy variable.

Table 13.8b: Parameters for Vector of Substitutes for Electricity: Biomass, Wind, and Solar PV.

Parameter or Quantity	**Biomass Crops**	**Biomass wastes: CHP**	**Wind: Inter-mittent**	**Wind: With storage**	**PV: Inter-mittent**	**PV: With storage**
Initial Costs: [a/] - Variable UScents/kWhe - Fixed US$/kW[b/] - Average UScents/kWhe[c/]	1.7 1,800 4.5	0.0[h/] 1,800 2.6	0.0 1,200 [i/] 6.0	0.0 3,400 [i] 6.8	0.0 4,000[j/] 30.0	0.0 11,000 [j,k] 33.0[n/]
Efficiency, kWhe/kWh of fuel%	40 [d/]	30 [g/]	-	-	-	-
Load factor, %	80	80	35 [f/]	70 (35) [f/]	22 [f/]	45 (22) [f/]
Waste heat utilized, % of kWh of fuel input[e/]		45%	-	-	-	-
Net CO_2 emissions: g/kWh[l/]	0.0	0.0	0.0	0.0	0.0	0.0
Unit NO_x emissions: g/kWh [l/]	0.9	0.9	0.0	0.0	0.0	0.0
SO_2 emissions g/kWh [l/]	0.5	0.5	0.0	0.0	0.0	0.0
PM emissions: g/kWh [l/]	0.16	0.16	0.0	0.0	0.0	0.0
Lifetime of plant, yrs	25	25	25	25	30	30
Leadtime for investment, yrs	4	4	2	3	1	1
Development lag, yrs	1	1	1	10	1	10
Substitution parameters: - Stndrd dvn: % mean - The parameter '*a*'	Numer-aire	0.3 6.0	0.3 6.0	0.3 6.0	0.5 3.0	0.5 3.0
Learning rate	0.2	0.2	0.25	0.25	0.3	0.3
Minimum cost: US$/kWhe	3.5	1.8	2.5	3.0	4.0[m/]	4.5 [m,n/]
Technical limits: % total market	10	10	20	None	20	None
Initial market shares (S_0), %	1 [o/]	1 [o/]	1 [o/]	p/	p/	p/

All costs derived from UK data are converted to $ at a ppp rate of $1.55/£

a/ Expressed in power and energy units per kW and kWh, since these are the most familiar quantities. To convert the latter to $/GJ multiply by 286 kWh/GJ. Cost estimates are available in the DTI report cited above, and in various chapters of the UNDP-WEC World Energy Assessment. The two sources are surprisingly consistent.

b/ Includes the capitalized value of the annual fixed costs of maintenance, which is usually expressed as a percentage of the capital cost. The figures here use 10% of capital cost. In the case of intermittent wind and PV, a 'a cost of intermittency' is added; this rises from being negligible at low rates of penetration to around US Cents 2.5/kWh at 20%. An average of US cents 1.3/kWh is assumed.

c/ Using a 10% discount rate.

d/ Assumed to be used in co-fired plant, with the same efficiency as coal stations.

e/ To attain the figure in brackets a doubling of wind turbine capacity and thus of capacity costs is required. The capital cost assumptions allow for this and also for 30% losses in storage. See footnote f. Similar remarks apply to PVs with storage.

f/ Capital costs of wind turbines today times 2 (to achieve higher load factors, when storage is used) divided by 0.9. See footnotes e and i. Similar remarks apply to PVs with storage. The high load factor for wind (35%) assumes a mix of offshore use (where load factors can be in the range 40-45%) and onshore use (where load factors are in the range 20-30%). The figure in brackets shows the underlying load factor assumption; the figure outside the brackets is the load factor assumption with storage. For PVs, the assumption is that use would be predominantly in the developing countries, southern Europe and Southern and Western US, where insolations are high: a figure of 2000kWh/sq. m. is assumed. In these regions there is a better co-incidence of the solar peaks and the demand peaks, which reduced storage requirements.

g/ The ratio of electrical output to energy of fuel input. The heat appears as a by-product used in the heating markets supplied by coal and gas. (See tables 13.2 and 13.5.)

h/ Could even be negative with benefits of reductions in landfill in the case of urban wastes and the benefits of improved fertilisers and land management practices in the case of agricultural and forest wastes. Against this there is the cost of transporting the fuels.

i/ For a mix of onshore and offshore wind, the former being $750/kW the latter $1800/kW. In the calculation of average cost a fixed cost equal to 10% of capital costs is added to provide for maintenance. For storage, pumped and compressed air storage are the markers; the figures assume $1,000/kW. Note that a round trip efficiency of storage of 0.7 is assumed (footnote f); some of the output would be used directly, and perhaps only one third would need to be stored; this implies a loss of 10% of the overall output of wind, not 30%.

j/ A credit (cost deduction) of $1000/kW is made to allow for the savings in distribution costs and losses, since PVs are a decentralised form of electricity supply.

k/ Based on the costs of the regenerable fuel cell, which are estimated to be £1,200//kW ($1800/kW). See table 1 in Anderson and Leach (2004). Thus the costs of the system with storage are assumed to be 2x$5000/kW for the PV modules plus $2000/kW (after allowing for losses) in the storage, less $1,000 per kW for savings in distribution costs.

l/ Assumed to be the same as those for ‘clean coal’.

m/ These seemingly low costs in the long term relate to the costs of PVs declining to around $1,000-1,500/kW, which are predicted in a number of studies. There will still be a credit for savings in the costs of electricity transmission and distribution.

n/ Note that the high costs of storage are largely offset by the increase in load factor that they permit.

o/ Figures rounded to nearest 1%.

p/ The initial market share will be determined by the level of demonstration effort—a policy variable—and the effects on substitution will not kick in until the development phase is completed.

Table 13.8c: Parameters for Vector of Substitutes for Electricity: Solar Thermal, Marine and Geothermal.

Parameter or Quantity	Solar thermal (intmnt)	Solar thermal + gas	Solar thermal + storage	Marine (inter-mittent)	Marine + storage	Geo-thermal
Initial Costs: [a] • Variable UScents/kWhe • Fixed US$/kW[b] • Average UScents/kWhe[c]	 0.0 3,000 16.0	 1.5[d] 3,250 [e] 5.5	 0.0 7,000 [b] 18.5	 0.0 2,500 10.0	 0.0 6,000 [b] 12.0	 0.0 2,000[h] 3.5
Efficiency, kWhe/kWh of fuel%	-	30	-	-	-	-
Load factor, %	25 [g]	80	50 [f]	35	70 [f]	80 [f]
Net CO_2 emissions: g/kWh[l]	0.0	0.0	0.0	0.0	0.0	0.0
Unit NO_x emissions: g/kWh [l]	0.0	0.0	0.0	0.0	0.0	0.0
SO_2 emissions g/kWh [l]	0.0	0.0	0.0	0.0	0.0	0.0
PM emissions: g/kWh [l]	0.0	0.0	0.0	0.0	0.0	0.0
Lifetime of plant, yrs	30	30	30	25	25	30
Leadtime for investment, yrs	3	3	5	3	2	3
Development lag, yrs	3	3	10	10	10	1
Substitution parameters: • Stndrd dvn: % mean • The parameter '*a*'	 0.3 6.0	 0.3 6.0	 0.3 6.0	 0.3 6.0	 0.5 3.0	 0.5 3.0
Learning rate	0.3	0.3	0.3	0.3	0.3	0.2
Minimum cost: US$/kWhe	3.5 [i]	2.1 [i]	5.3 [i]	4.0[j]	6.0	2.5
Technical limits: % total market	10	50	50	40	30	10
Initial market shares (S_0), %	l/	l/	l/	l/	l/	1 [o]

Note: All costs derived from UK data are converted to $ at a ppp exchange rate of $1.55/£

a/ Expressed in power and energy units per kW and kWh, since these are the most familiar quantities. To convert the latter to $/GJ multiply by 286 kWh/GJ. Cost estimates are available in the various chapters of the UNDP-WEC World Energy Assessment. (See especially chapter 7.)

b/ Includes the capitalized value of the annual fixed costs of maintenance, which is usually expressed as a percentage of the capital cost. The figures here use 10% of capital cost. The capital costs of storage, are assumed to be $1000/kW. Note that if solar thermal is used to complement existing hydro plant, the costs of storage are negligible, since the effect is to reduce the drawdown of the latter.

c/ Using a 10% discount rate.

d/ Assuming a 25% solar fraction, making the costs of gas per total kWh generated three quarters of those in table 13.6a.

e/ The costs of the gas firing for steam generation.

f/ It is assumed the storage is sufficient to double the load factor.

g/ Solar thermal for electricity generation is only suitable in regions with very high isolation, of over 2,500kWh/sq. m., the figure assumed here.

h/ The costs of geothermal are highly region specific. Turkenburg (UNDP/WEC Chapter 7)reports that they can vary between $200 and $2000/kW, depending on site.

i/ Assumes costs of solar field component plus the costs of the boiler-generator, will come down the $1000/kW.

j/ Assumes costs come down to $1,000/kW

k/ Rounded to nearest 1%

l/ The initial market share will be determined by the level of demonstration effort—a policy variable—and the effects on substitution will not kick in until the development phase is completed.

Table 13.8d: Parameters for Vector of Substitutes for Electricity: Coal and Gas, with sequestration; Hydrogen, centrally produced; and Hydrogen for micro-CHP.

Parameter or Quantity	Gas: With CO_2 sequestration	Coal: With CO_2 sequestration	H_2: centrally produced	H_2: Micro-CHP
Initial Costs:[a] • Variable UScents/kWhe • Fixed US$/kW • Average UScents/kWhe[b,c]	 2.5 800 3.8	 1.8 2,500 6.0	 5.2[h] 800[g] 6.5	 8.0 – 0.2[j] 2,200[i] 12.0
Efficiency, kWhe/kWh of fuel%	48	40	50	50
Load factor, %	80	80	80	50[f]
Waste heat utilized, % of kWh of fuel input				30%
Net CO_2 emissions: g/kWhe	0.0	0.0	0.0	0.0
Unit NO_x emissions: g/kWhe	0.09[d]	0.9[e]	0.0001[d]	0.0001[d]
SO_2 emissions g/kWhe	0.0	0.5[e]	0.0	0.0
PM emissions: g/kWhe	0.0	0.16[e]	0.0	0.0
Lifetime of plant, yrs	30	30	30	25
Leadtime for investment, yrs	4	5	5	2
Development lag, yrs	5	5	10	10
Substitution parameters[k]: • Stndrd dvn: % mean • The parameter '*a*'	 0.3 6.0	 0.3 6.0	 0.3 6.0	 0.3 6.0
Learning rate	0.2	0.2	0.3	0.3
Minimum cost: US$/kWhe	3.5	4.5	4.5[h]	3.5[j,l]
Technical limits: % total market	None	None	None	None
Initial market shares (S_0), %	m/	m/	m/	m/

Note: All costs derived from UK data are converted to $ at a ppp rate of $1.55/£

a/ Expressed in power and energy units per kW and kWh, since these are the most familiar quantities. To convert the latter to $/GJ multiply by 286 kWh/GJ. Cost estimates are available in the UNDP-WEC World Energy Assessment (see especially chapter 8) and the DTI Economics Paper No. 4 (2003, Table 1).

b/ Includes the capitalized value of the annual fixed costs of maintenance, which is usually expressed as a percentage of the capital cost. The figures here use 10% of capital cost. The capital costs of storage, are assumed to be $1000/kW. Note that if solar thermal is used to complement existing hydro plant, the costs of storage are negligible, since the effect is to reduce the drawdown of the latter.

c/ Using a 10% discount rate.

d/ As for GTCC

e/ As for clean coal

f/ For individual units, Hawkes and Leach (2004) find that load factors are quite low. This relatively high load factor for small units assumes some export of the surplus power back to the grid, encouraged, for example, by net metering.

g/ As for gas turbines

h/ Based on the costs of hydrogen production from the marker technology (gas) at $15/GJ initially declining to a minimum of $10/GJ. The capital costs decline from $800/kW to $700/kW.

i/ These are the capital costs of approximately $3000/kW minus the savings in the costs of investment in electricity distribution, which are put at $1000/kW. Fixed maintenance is assumed to amount to 10% of the annuitised capital cost (about $25/kW/year). For further discussion, see Anderson and Leach (2004).

j/ Includes distribution costs of UScents 2.8/kWh, minus 0.3 (the heat provided per unit of kWh electrical output) times the value of heat, which is taken to be the costs per GJ from gas or coal (see tables 13.3 and 13.6).
k/ A wide dispersion of possibilities is assumed on account of the wide dispersion in the costs of coal and gas around the world. The parameters are the same as those for Table 13.8a.
l/ This implies the capital cost savings on electricity distribution would exceed the capital costs of a micro CHP unit were to decline below, which is thought to be possible. (The costs of electricity distribution are around $1000/kW.)
m/ The initial market share will be determined by the level of demonstration effort—a policy variable—and the effects on substitution will not kick in until the development phase is completed.

13.8 Traditional Biomass

For equation B1 in section 12 ($D_t^b = \alpha(y_t)^{-\gamma} \cdot N_t \cdot \eta_{bt}$), the following parameters are suggested:

- Initial condition: D_0^b = 40 Exajoules (EJ = 10^{18} Joules).
- Per capita income elasticity, γ = 1.4
- Initial per capita income for developing countries, y_0 = $3,900 (PPP units, in 2001).
- Initial population, N_0 = 5,200 million (in 2001).
- Efficiency of use: η_{bt} = 15%, an average of open fires and wood stoves, rising to 60% for LPG and kerosene stoves.
- Value of constant, α = 280

The per capita income and population data are taken from the World Bank's 2003 World Development Report, and on stove efficiency from Goldemberg's review (Chapter 10 of UNDP/WEC 2000).

Emissions of all pollutants from the use of biomass for cooking are extra-ordinarily large—and also highly variable, depending whether an open fire or a stove is used. The following are based on data presented in Kirk-Smith's review (Chapter 3 of UNDP/WEC 2000):

	Grams/m^3 of wood	Grams/GJ
Particulates	0.15	0.017
Carbon monoxide	0.0033	0.0004
Methane	5.1	0.57
Carbon dioxide	403.0	45.0

Assumptions: 1 cubic meter of dry wood = 0.5 tonnes. Calorific value = 18GJ/tonne. Kirk-Smith gives indoor concentrations of PM and CO per kg of wood burned on an indoor stove; to the extent that these are vented, the estimates of the above table are understated. This makes these co-efficients less relevant (in the case of PM and CO) for analyses of the greenhouse effect, for which alternative estimates will be needed; on the other hand, they are the appropriate co-efficients for looking at health effects.

13.9 A Comment on Regional Disagregation

The above parameters were for global conditions. Several parameters can be based on international values—e.g. e.g world prices for the various technologies and international values for emissions coefficients. Regional variations in total emissions will differ enormously per unit of output; but this can be almost wholly attributed to the choice of technologies, for example the 'vintages' in use, the extent of 'clean' technologies in use. Thus the main differences between regions will ultimately lie in the differences in policies, not in the underlying parameters.

There are two exceptions. One concerns the technical limits to the amount of a resource that can be used, the main example being the availability of land for biomass production. The other is the substitution parameter, *a*, which as discussed in the text varies inversely with the standard deviation of the distribution of possibilities. As these are obviously greater at the global than at the country level, the value of *a* will increase with disaggregation.

Table 13.9 provides a guide to the adjustments required for more disaggregated models.

Table 13.9 Summary of Likely Effects of Regional Disaggregation on the Parameters

Characteristic	**Units**	**Comments**
1. Unit capital costs	US$/kWe	World prices are a good basis with local adjustments for transport costs. Tax and environmental policies will be the main source of relative price differences between regions
2. Unit coal input	Mtoe or GJ/GWh	
3. Unit gas input	Mtoe or GJ/GWh	
4. Unit oil input	Mtoe or GJ/GWh	
5. Unit CO_2 emissions	kg/kWh or GJ	Again international data can be used, since technologies similar. The principal differences will arise from the vintages of technologies in use.
6. Unit SO_2 emissions	kg/kWh or GJ	
7. Unit NOx emissions	kg/kWh or GJ	
8. Unit PM10 emissions	kg/kWh or GJ	
8. Load factor	ratio	Region specific, but differences not large
9. Lifetime	years	Similar across regions
10. Installation lag	years	Installation lags similar, but development lags longer in developing countries
11. Development lag	years	
12. Learning rate	% or per unit rate	Use a ‘world’ learning rate, but with a longer development lag in developing regions
13. Substitution parameter	See subtn equtns	The greater the disaggregation, the lower the dispersion or standard deviation and the higher the value of this parameter (see text).
14. Minimum cost	US$/GJ	World prices a basis
15. Technical limits	% of total supply	Varies by region, especially biomass
16. Infrastructure costs	US$/GJ	World costs of infrastructure components a starting point, with local adjustments
17. Other unit costs (e.g. O&M)	US$/GJ	Usually a % of capital costs. Hence world prices are a good basis

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Appendix 1

Equations Used in the Example of the Hydrogen-Electric Scenario[35]

The demand for electricity (in capacity units) D_{et} is exogenous with a growth rate of g and is expressed relative to year 0:

$$D_{et} = D_{e0}(1+g)^{t} \qquad \text{(A1-1)}$$

Investment requirements I_{et} each year, if δ is the retirement rates are:

$$I_{et} = D_{et} - D_{et-1} + \delta D_{et-1} \qquad \text{(A1-2)}$$

Markets shares in electricity production from renewables, hydrogen and fossil fuels are respectively denoted by S_{ert}, S_{eht} and S_{eft}, and the changes in prices of renewables and hydrogen relative to fossil fuels by ΔP_{ert} and ΔP_{hrt}.[36] There is no limit in principle to the production from hydrogen or fossil fuels, but there is one, thought to be around 20% of total demand, for intermittent renewables, depending on the diversity of the renewable energy mix. This is denoted by $\hat{S}_{ert}$, and is determined be the inequality (A1-10) below.

$$S_{ert} = S_{ert-1} + a_{er} S_{ert-1}(\hat{S}_{ert-1}(1 - S_{eft-1}) - S_{ert-1})\Delta P_{ert} \qquad \text{(A1-3)}$$

$$S_{eht} = S_{eht-1} + a_{eh} S_{eht-1}(1 - S_{eft-1} - S_{eht-1})\Delta P_{eht} \qquad \text{(A1-4)}$$

$$S_{eft} = 1 - S_{ert} - S_{eht} \qquad \text{(A1-5)}$$

Cumulative net investment is denoted by U, using the same notation for the subscripts:

$$U_{ert} = U_{ert-1} - \delta U_{ert-1} + S_{ert} I_{et} \qquad \text{(A1-6)}$$

$$U_{eht} = U_{eht-1} - \delta U_{eht-1} + S_{eht} I_{et} \qquad \text{(A1-7)}$$

$$U_{eft} = D_{et} - U_{ert} - U_{eht} \qquad \text{(A1-8)}$$

Next, there is the demand for electrolytic hydrogen from renewable energy. Denote this by D_{hrt}. The electricity requirements for this will equal the demand for hydrogen for electricity production divided by the conversion efficiency, denoted here by η:

$$D_{hrt} = U_{eht} / \eta \qquad \text{(A1-9)}$$

Last, there is the relationship needed for $\hat{S}_{ert}$. If the maximum amount of intermittent renewables on the system, as a proportion of demand is defined by $\hat{U}_{ert} / D_{et}$, then:

$$\text{If } D_{et}\hat{U}_{ert} - U_{ert} > I_t \text{, then } \hat{S}_{ert} = 1 \text{, otherwise } \hat{S}_{ert} = (D_{et}\hat{U}_{ert} - U_{ert}) / I_t \qquad \text{(A1-10)}$$

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[35] The spreadsheet with the equations set out and the parameter assumptions will be made available separately.

[36] When the demand and investment equations are in capacity units, then the relative prices need to be based on the sum of the present worth of the capital, operating and fuel costs per unit of capacity.

Appendix 2

Equations Used in the Example of the Hydrogen-Transport Scenario[37]

There is an exogenous demand for transport fuels based on analysis of diesel and petrol vehicle. Denote this be D_{Tt} and its growth rate by g.

$$D_{Tt} = D_{T0}(1+g)^t \qquad \text{(A2-1)}$$

The investment requirements are given by the following, with δ_T denoting the average retirement rate of the vehicle fleets (typically around 1/10 to 1/15):

$$I_{Tt} = D_{Tt} - D_{Tt-1} + \delta_T D_{Tt-1} \qquad \text{(A2-2)}$$

and the shares in new investment by:

$$S_{Tht} = S_{Tht-1} + a_T S_{Tht-1}(1 - S_{Tht-1})\Delta P_{Tht} \qquad \text{(A2-3)}$$

$$S_{Tft} = 1 - S_{Tht} \qquad \text{(A2-4)}$$

Next there are the equations for net cumulative investment:

$$U_{Tht} = U_{Tht-1} - \delta U_{Tht-1} + S_{Tht} I_{Tt} \qquad \text{(A2-5)}$$

$$U_{Tft} = 1 - U_{Tht} \qquad \text{(A2-6)}$$

Equations are now required to determine how to meet the demand for hydrogen, either from, say, the steam reforming of natural gas or gas produced by coal gasification, or through electrolysis from a renewable energy source. Let D_{Ht} denote the demand for hydrogen:[38]

$$D_{Ht} = U_{Tht} \qquad \text{(A2-7)}$$

The investment requirements for hydrogen production are then given by:

$$I_{Ht} = D_{Ht} - D_{Ht-1} + \delta_H D_{Ht-1} \qquad \text{(A2-8)}$$

The equations for market shares in new investments for hydrogen production follow the same form as before, the subscripts *Hr* and *Hf* denoting its production from renewable energy and fossil fuels respectively:

$$S_{Hrt} = S_{Hrt-1} + a_H S_{Hrt-1}(1 - S_{Hrt-1})\Delta P_{Hrt} \qquad \text{(A2-9)}$$

$$S_{Hft} = 1 - S_{Hrt} \qquad \text{(A2-10)}$$

Lastly, there is the total output of hydrogen from the two sources:

$$U_{Hrt} = U_{Hrt-1} + S_{Hrt} I_{Ht} - \delta_H U_{Hrt-1} \qquad \text{(A2-11)}$$

$$U_{Hft} = D_{Ht} - U_{Hrt} \qquad \text{(A2-12)}$$

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[37] The spreadsheet with the equations set out and the parameter assumptions will be made available separately. The notation below is similar to that used for electricity in Appendix 1, except that T is used to denote transport where e was used for electricity. AUTHOR’S NOTE: I now think (April 14) there are some redundancies in the above equations. They do not effect the results, but will be removed in the next draft.

[38] There is a calculation of the efficiency effect of hydrogen fuel cell vehicle shown in the text, which is obtained by multiplying this equation by 0.5—the average ratio of the fuel used (in energy units) by the vehicle relative to the internal combustion engine using oil fuels.

Appendix 3

A Note on the Univariate and Bivariate Cases

The relationship between S_t and P_t postulated here is the familiar logistic or ‘S’ curve used for the analysis of the demand for new durable goods, except that the rate of change in market share is expressed with respect to the relative prices rather than the change in time. In continuous form:

$$dS/dP = aS(1-S) \tag{A3.1}$$

The solution to which is:

$$S(t) = \frac{e^{a(P(t)-1)}}{1+e^{a(P(t)-1)}} \tag{A3.2}$$

The bivariate case considers the market shares of two different technologies, notated S_1 and S_2. Although this case is more complicated, the equations for S_1 and S_2 can still be written in terms of the relative prices if certain assumptions are made.

We have:

$$\begin{aligned} dS_1/dP_1 &= aS_1(1-S_1-S_2) \\ dS_2/dP_2 &= aS_2(1-S_1-S_2) \end{aligned} \tag{A3.3}$$

As far as we know there is no explicit solution to the these equations. A partial solution can be derived for particular values of S_2 in the first equation and of S_1 in the second, by assuming dS_1/dP_2 = 0 and dS_2/dP_1 = 0. Then

$$\frac{d\,\underline{S}}{d\,\underline{P}} = J = \begin{bmatrix} aS_1(1-S_1-S_2) & 0 \\ 0 & aS_2(1-S_1-S_2) \end{bmatrix} \tag{A3.4}$$

So that

$$\int J^{-1} d\,\underline{S} = \int d\,\underline{P} \tag{A3.5}$$

which implies

$$\int \frac{1}{aS_1(1-S_1-S_2)} dS_1 = \int dP_1 \,. \tag{A3.6}$$

Integrating from P_{10} to P_{1t}:

$$P_{1t} - P_{10} = \int \frac{1}{aS_1(1-S_1-S_2)} dS_1$$

$$\Rightarrow \quad P_{1t} - P_{10} = \frac{1}{a(1-S_2)} \int \frac{1}{S_1} + \frac{1}{1-S_1-S_2} dS_1 \tag{A3.7}$$

And integrating from S_{10} to S_{1t}

$$P_{1t} - P_{10} = \frac{1}{a(1-S_2)} \ln\left(\frac{S_{1t}(1-S_2-S_{10})}{S_{10}(1-S_2-S_{1t})} \right) \tag{A3.8}$$

Solving for S_{1t}:
$$S_{1t} = \frac{S_{10}(1-S_2)}{1-S_2-S_{10}} . \frac{e^{a(P_{1t}-P_{10})(1-S_2)}}{1+\frac{S_{10}}{1-S_2-S_{10}} e^{a(P_{1t}-P_{10})(1-S_2)}} \qquad \text{(A3.9)}$$

When $P_{10} = 1.0, S_{10} = 0.5$. The equation simplifies to:

$$S_{1t} = (1-S_2)\frac{e^{a(P_{1t}-1)(1-S_2)}}{1+e^{a(P_{1t}-1)(1-S_2)}} \qquad \text{(A3.10)}$$

Similarly:
$$S_{2t} = (1-S_1)\frac{e^{a(P_{2t}-1)(1-S_1)}}{1+e^{a(P_{2t}-1)(1-S_1)}} \qquad \text{(A3.11)}$$

Appendix 4
Note on the Logistic Distribution

As discussed in the text, the relationship postulated between S_t and P_t for this work is the logistic or ‘S’ curve, which has the cumulative distribution function:

$$S(P) = \frac{e^{a(P-1)}}{1+e^{a(P-1)}} . \qquad \text{(A4.1)}$$

The probability density function is:

$$\frac{dS}{dP} = \frac{ae^{a(P-1)}}{1+e^{a(P-1)}} = aS(1-S) . \qquad \text{(A4.2)}$$

For a logistic distribution it has been shown that the cumulative distribution can be expressed as[39]:

$$S(x) = \frac{e^{(x-A)/B}}{1+e^{(x-A)/B}} \qquad \text{(A4.3)}$$

where the mean is A and the variance is $\frac{1}{3}(\pi B)^2$. Comparing co-efficients in (1) and (3) the logistic distribution being considered in this paper has a mean of 1 and a variance of $\frac{1}{3}(\pi / a)^2$, where *a* is the substitution parameter.

The distribution is symmetrical, such that the third moment (a measure of asymmetry) usually, notated μ_3 / σ^3, is zero. There is however a fourth moment (kurtosis), usually notated by μ_4 / σ^4 - 3. Subtracting three from this value serves as a correction to make the kurtosis of the normal distribution equal to zero. For the logistic distribution coefficient of kurtosis is equal to 6/5.[40]

The analysis in the text assumes that the frequency distributions of the possibilities are approximately symmetrical. The resulting ‘S’ curve captures the exponential growth of opportunities in the early phases of expansion and diminishing possibilities as market saturation levels are approached. Asymmetrical alternatives to (2) might take the following form:

$$f(P) = dS / dP = aS^n(1-S) , \qquad \text{(A4.4)}$$

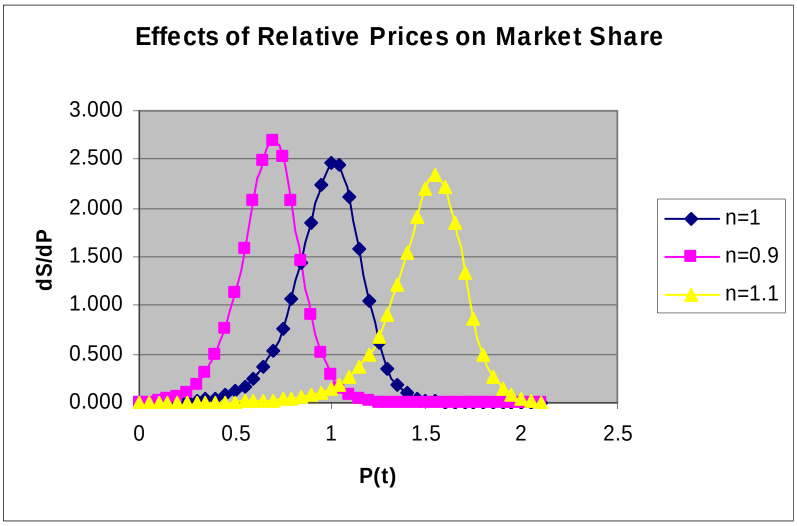
For values of *n* not equal to one, the distribution is asymmetrical around *P*(*t*)=1.0. The following graph shows the effect of allowing *n* to take on values other than one. Comparing the results when *n=0.9*, *n*=1.0, and *n*=1.1, the asymmetry is immediately apparent:

---

[39] Virtual Laboratories: http://www.ds.unifi.it/VL/VL_EN/special/special13.html

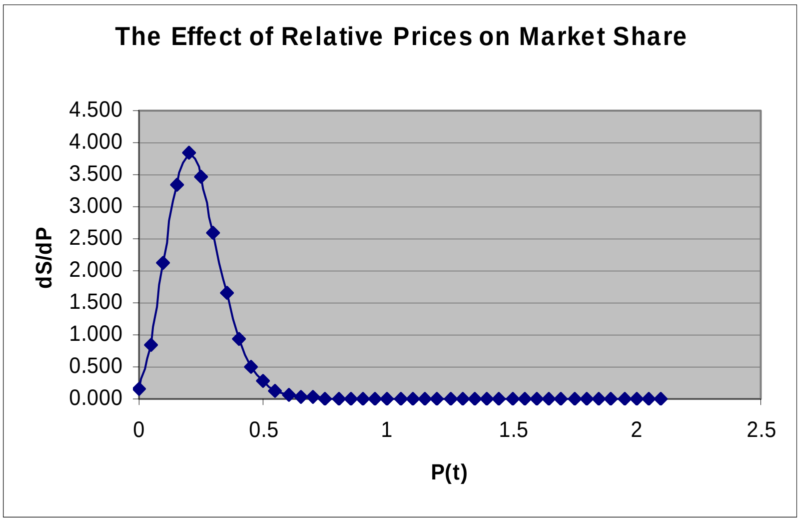
[40] Compendium of Common Probability Distributions: www.causascientia.org/math_stat/Dists/Compendium.pdf

Figure 1:



Changing the values of *n* more substantially naturally results in a great degree of asymmetry as apparent when *n=0.5* as in Figure 2.

Figure 2:



Though using different values of *n* alters the rate of change in market shares relative to the change in price, it does not change the fact that a switch to new, low-carbon technology will occur as the price decreases. Still, it is important to note the effect that changing the value of *n* has on the model results as this assumption that *n*=1.0 does have a significant effect.

Appendix 5: Notes on Hydrogen production, Storage and Use

The following is copied from a report for the Carbon Trust by ICEPT (2001):

Hydrogen is a carbon-free energy carrier that has potential uses in many applications. For example, it can fuel vehicles, provide process heat for industrial processes, supply domestic heating needs through cogeneration or heat recovery systems, and fuel power plants for centralised or distributed generation. It burns cleanly and efficiently and can be used in modified conventional combustors to ease the transition to a completely new energy infrastructure based on the hydrogen in fuel cells or gas turbines for energy conversion. The level of CO_2 emissions reduction compared with conventional technologies will depend on how the hydrogen is produced. When it is produced via electrolysis of water using nuclear or renewable electricity, CO_2 is absent from the fuel cycle. It can also be produced directly from gas, coal bed methane or gasified coal, with the carbon being sequestered.

Expanded RD&D is needed on biological, thermochemical and electrochemical processes for producing hydrogen. Research is also needed on hydrogen storage technologies such as those based on innovative materials – for example, carbon fibres and structures and metal hydrides.

Cost of hydrogen. There are two elements in the hydrogen cost equation - cost of manufacture and cost of distribution to the end user. The equation is further complicated by choice whether to make hydrogen centrally and distribute - either as a high-pressure gas, stored in a convenient medium or cryogenically as a liquid - or to make it on-site in small plant. This provides a number of possible pathways to examine. In this section we compare the costs of manufacture from a variety of raw materials in both small and large plant, the costs of distribution and finally the delivered costs to the end user

Manufacture. Because of its presence in so many compound forms it is possible to make hydrogen from almost anything - all hydrocarbon fuels, biomass and water. The processes that must be used have all been shown to be technically feasible, though many of them require great improvements before they can be economically introduced. The following table summarises the costs of some processes that have been analysed in depth.

Table A5.1: Current and projected costs of gaseous hydrogen (ca 20 bar) $/GJ

	Near term	**Long term**	
Renewable sources			
Hydrogen from biomass gasification - large plant (18,000GJ/day ca 60Mscfd)		7-10	Technology still remains to be demonstrated on a commercial scale. Assumes fuel cost in range $2-4/GJ
Electrolytic Hydrogen (180 GJ/day)			
Solar PV	24-41	15-25	
Wind	20-45	17-25	
Solar thermal SW US	45-75	25-35	
Off-peak hydroelectricity	10-20	10-20	
Fossil Sources			
Steam Reforming natural gas • Large plant (18,000GJ/day	4-7	4-7	Assumes a gas price of $2.5/GJ for large plants and $4/GJ for small plants

ca 60MMscfd or 144 tonnes/day • Small plant (180 GJ/day - ca 0.6MMscf or 1.4 tonnes /day)	11-14	11-14	45-60% projected H2 costs due to natural gas with capex ca 40% - long term. H2 costs driven primarily by outlook on natural gas prices - compact processors would yield costs close to the low end of the range for small plant.
Coal gasification • Large plant (18,000 GJ/day) • Medium plant (9,000 GJ/day)	9 13		Assumes coal prices at $1.5/GJ
Residue/coke gasification • Large plant (18,000GJ/day)	7-11		Assumes coke and residue prices at $ 1.4-2.7/GJ

Sources: Based on Lipman and DeLucchi (Hydrogen-fuelled vehicles Int J of Vehicle Design 1996), Berry (Hydrogen as a Transport Fuel: Costs and Benefits Lawrence Livermore Laboratory 1996) and the IEA Automotive Fuels Survey 1997. Also Gregoire-Padró and Putsche, Survey of the Economics of Hydrogen Technologies, National Renewable Energy Laboratory 1999.

In the short term, producing hydrogen from natural gas by steam reformation is the cheapest method and one of the cleaner methods involving hydrocarbon-based processes. In the longer term, biomass gasification offers production at a competitive cost if current developments can be brought through into commercialisation.

Storage and transportation. In the long term moving hydrogen around is best done using a pipeline, one that is similar to those used for natural gas. This will require a considerable investment in infrastructure and is unlikely to be achieved in the short term, apart from the dedicated pipelines that connect large producers and consumers of hydrogen at present in France, Germany, the US and Canada. However, it is also possible to transport hydrogen in the natural gas network with relatively little modification, and this may be the best option if it can be brought about. Adding hydrogen to natural gas is an effective way of improving the combustion properties and cleanliness of the fuel, and the proportion of hydrogen can be gradually increased. This means of transporting hydrogen is limited to ca 15-20% hydrogen by volume, before modification of existing burners and other end-use technologies is required.

In the near term there are a variety of pathways by which hydrogen could be delivered to the end user. The biggest problem arises from its low volumetric energy density. All pathways seek either to increase in some way. Possible pathways include:

1. Central manufacture and distribution as:
   - Cryogenic liquid
   - As a gas in high pressure containers (operating at some combination of pressure and temperature to minimise costs and maximise energy density)
   - Physically adsorbed or combined as a hydride
2. Central manufacture of a hydrogen rich carrier which can be more effectively distributed and from which the hydrogen can be easily recovered at the central re-fuelling site:
   - low molecular weight hydrocarbons (natural gas, LPG, naphtha etc.)
   - Methanol or ammonia
3. Manufacture by local electrolysis of water using off-peak electricity

It is estimated that, using current technology, hydrogen would cost roughly $11-15/GJ for a refuelling outlet servicing 300 cars/day (Gregoire-Padró and Putsche, 1999). For comparison the cost of gasoline delivered to a retail outlet is $4-6/GJ ($14 -$20/bbl crude price). A hydrogen fuel cell vehicle would have two-to-three times the energy efficiency of a conventional ICE. Under this scenario, fuel costs per mile become comparable.

Using hydrogen. Hydrogen will burn in IC engines, turbines and gas boilers in the same way as the primary hydrocarbon (HC) fuels, but can also be used directly in fuel cells at high efficiency to provide heat and electrical outputs. Using hydrogen in conventional engines is perfectly feasible and produces almost no emissions, but there is some NO_X related to any high temperature combustion process and there are hydrocarbons associated with lubricating oils. Safety is sometimes raised as an issue, but all analysis and operating experience so far shows that this is not a factor to be weighed against it as compared with other fuels.

The main issue with hydrogen is that it is a gas with very low volumetric energy density. Distribution and storage (either in bulk form e.g. retail sites and distributed power, or on board vehicles) are complex, costly and inefficient processes as evidenced by the cost data provided in the previous section.

As noted the ideal way to distribute bulk hydrogen is by pipeline and, although pipeline systems do exist, they are small compared with the extensive natural gas systems (e.g. the US has 2m km of natural gas pipeline to which 96% of the population has access). Mixtures of hydrogen and natural gas, up to 20% volume hydrogen, offer some benefits when burned in an IC engine and can use the natural gas networks. Such mixtures, often referred to as hythane, may present an entry option for bulk hydrogen.

Storage issues generally revolve around volumetric density, gravimetric density, cost and, for vehicles, refill time. This is an active area of research in which the aim is to achieve the energy density of conventional fuels at a comparable cost. For hydrogen use in vehicles, gasoline is generally taken as the benchmark. Estimated costs of storage, on-site facilities and re-fuelling times for the range of systems described above are summarised below:

Table A5.2 Costs and Refuelling Times for Hydrogen Compared with those for Gasoline

System	Container cost equivalent 50ltr gasoline tank)	Refuel time (mins)	Station costs $/GJ
Gasoline	30	2-3	0.6
Compressed	2000	3-5	4-6
Compressed and cooled	2000+	5+	5+
Liquid Hydrogen	500-1000	2-5	3.5-5
Hydride	1500-3000	20-30	3-4
Cryo adsorption	1000-2000	5	4-5

To sum up, a low carbon economy is to be attained in the long-term, the development of the hydrogen option will be crucial. This is not a new conclusion—it was central to the idea of the 'nuclear economy' four decades ago, when it was envisaged that nuclear energy would be used to generate hydrogen for transport, and it was revisited again during the oil price shocks of the 1970s. Developments have continued, however, and much progress has been made. It remains an important area for RD&D, stimulated by promising developments in the fuel cell.

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The trans-disciplinary Tyndall Centre for Climate Change Research undertakes integrated research into the long-term consequences of climate change for society and into the development of sustainable responses that governments, business-leaders and decision-makers can evaluate and implement. Achieving these objectives brings together UK climate scientists, social scientists, engineers and economists in a unique collaborative research effort.

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