Representing energy technologies in top-down economic models using bottom-up information[1]

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1. Introduction

The threat of climate change due to the atmospheric accumulation of greenhouse gases has led to the development of numerous models of the complex socio-economic systems that drive anthropogenic emissions. Such models form a key component of integrated climate policy analysis. A critical factor for future anthropogenic emissions is the rate and magnitude of technological change toward low- or no-carbon emitting technologies (IPCC, 2001). Two broad approaches exist for modeling the interaction between energy, economic, and environmental systems and technology (van der Zwaan, 2002). The bottom-up approach depicts a rich set of representative energy using technologies at a level of detail such that engineering studies can be used to cost out a representative example (e.g., a 500 megawatt coal fired power plant, or a 1 megawatt wind turbine). The technologies are typically described as a set of linear activity models based on engineering data of life cycle costs and thermodynamic efficiencies. These models can be used to identify, for example, the least-cost mix of technologies for meeting a given final energy demand under greenhouse gas emissions constraints. They often take energy and other prices as exogenous and, therefore, may overestimate the potential penetration of a technology such as natural gas combined cycle power generation if, for example, its widespread use causes gas prices to rise.

Top-down models, the second modeling approach, typically represent technology using relatively aggregated production functions for each sector of the economy. For example,

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electricity production may be treated as a single sector with capital, labor, material, and fuel inputs. Continuous substitution among inputs (e.g., between gas and coal or between fuels and capital) represents what is in the bottom-up approach a discrete shift from one technology to another. The particular focus of the top-down approach is market and economy-wide feedbacks and interactions, often sacrificing the technological richness of the bottom-up approach.

The simple characterization of these two modeling approaches is used here only to provide a basic distinction for the reader who is not familiar with the decades-long debate about the pros and cons of these approaches. We make no attempt to describe the great diversity of models that include features of both the top-down and bottom-up approaches. This paper reviews our efforts to enhance the technological richness of a top-down economic model using bottom-up engineering information. In this regard, we have chosen to use a computable general equilibrium (CGE) model of the world economy – the MIT Emissions Prediction and Policy Analysis (EPPA) model. Among the various top-down approaches, CGE models are the most complete in representing economy-wide interactions, including international trade, energy supply and demand, inter-industry demand and supply for goods and services, factor markets, and consumer demands. On the other hand they are often the least rich in their representation of technological details.

In the work discussed here, we introduce three new electricity generation options that compete with the existing electricity generation technologies in the EPPA model. The three new power generation technologies are: 1) a natural gas combined cycle technology (advanced gas or NGCC) without carbon capture and sequestration, 2) a natural gas combined cycle technology with carbon capture and sequestration (gas CCS), and 3) an integrated coal gasification technology with carbon capture and sequestration (coal CCS). These compete in the EPPA model's electricity sector with conventional fossil generation, nuclear, hydro, wind, and biomass power generation. We focus on these particular sequestration technologies because David and

Herzog (2000) identify these technologies – natural gas combined cycle generation with capture via amine scrubbing of the flue gas, and integrated coal gasification combined cycle generation with pre-combustion capture of the carbon dioxide (CO_2) – as two of the most promising technological options for producing electricity from fossil fuels with low CO_2 emissions.

The term carbon capture and sequestration as used herein refers only to these two fossil energy technologies and the subsequent capture (the separation of the CO_2 from the flue or pre-combustion gases) and sequestration (the deposition of the CO_2 into a reservoir). Other energy sources and capture processes are often considered under the umbrella of carbon capture and sequestration technologies, but they are not evaluated here. Previous work with the EPPA model (Biggs, 2000) has demonstrated the need to introduce NGCC technology without carbon capture to accurately assess the marginal additional cost of the carbon capture and sequestration technology. The NGCC without carbon capture and sequestration represents a technology that was not widespread for the 1995 base year of the EPPA model, but is widely seen as the most likely technology to be installed where new capacity is needed, assuming natural gas prices do not rise greatly relative to other fuels. This paper describes the method of analysis and the results obtained from introducing these technologies into multiple regions of a general equilibrium, global economic model. This analysis expands upon previous work (Biggs, 2000; Kim and Edmonds, 2000; and Dooley, Edmonds, and Wise, 1999) by introducing CCS technologies into multiple regions of a CGE model.

We begin with an overview of the MIT EPPA model in Section 2. Section 3 presents the bottom-up engineering cost model information and considers the translation of bottom-up information into the data required for a top-down representation. The next three sections then discuss specific issues that arise in assuring that the CGE representation of the technology accurately represents key engineering information and that market penetration of the technology is realistically represented. In particular, Section 4 examines the treatment of thermodynamic energy efficiency within production functions. Section 5 describes our approach for modeling technology penetration. Section 6 describes our methods of capital stock vintaging and malleability. Finally, Section 7 describes results of policy simulations.

2. The MIT EPPA Model

The EPPA model is a recursive dynamic multi-regional general equilibrium model of the world economy developed for the analysis of climate change policy as explained in Babiker, *et al.* (2001). The current version of the model is built on a comprehensive energy-economy data set, GTAP-E as described by Hertel (1997), that accommodates a consistent representation of energy markets in physical units as well as detailed accounts of regional production and bilateral trade flows. The base year for the model is 1995, and it is solved recursively at 5-year intervals through 2100 to capture the long-term dynamics of resource scarcity and capital stock turnover. EPPA consists of twelve regions, which are linked by international trade, nine production sectors, and a representative consumer for each region as shown in Table 1. Capital, labor, and a fixed factor resource for each fossil fuel and for agriculture comprise the primary factors of production.

Table 1 about here

Constant elasticity of substitution (CES) functions are used to describe production and consumption within each region and sector. CES functions take the form of Equation 1and have an elasticity of substitution σ, related to r (r=(1-s)/s), that is constant as relative price of inputs change.

$$Y = \left[A_1 X_1{}^r + \ldots + A_m X_m{}^r\right]^{1/r} \tag{1}$$

In Equation 1, Y is output, X_m, m =1,..,n, are inputs, and the A_m are share parameters. Under base year conditions, normalizing prices to 1.0, the A_m are the actual input shares in production, S_m. The factor shares, S_m, are the percentage of each input required to produce the output, Y. The sum of S_m over all n equals unity. A limiting feature of the CES function is that with more than 2 inputs the elasticity of substitution is identical between all pairs of inputs. This limit is overcome by ‘nesting’ inputs, that is, by representing sub-groups of inputs as separate CES functions, and aggregating these nests using CES functions. It is then possible to specify a separate elasticity for each of these nests. As we discuss in the next section, the main purpose of using engineering cost data is to use it to parameterize a CES production function like that in Equation 1.

As previously identified, the EPPA model includes a conventional fossil electricity sector and separate nuclear, hydro, biomass, and combined wind and solar generation technologies. While the representation of individual technologies allows one form of technical change in the solution, three other characterizations of technical change exist within the EPPA model. First, exogenous improvements in labor and land productivity create higher levels of output for a given labor and land input. A second source of technology improvement is an autonomous energy efficiency improvement factor or AEEI. Similar to the labor productivity improvement, it represents non-price induced technological change that lowers the amount of energy input required in intermediate production sectors and in final consumption. The AEEI means that less energy is used with no additional inputs so that there are economic savings as a result. Bottom-up analysis of specific technological options often find technologies that are not yet fully adopted that would save producers and consumers money: the AEEI does the same thing in the EPPA model and a similar factor is used in most other top-down models. A third way in which technological change is represented in the EPPA model is through price induced input substitution. Substitution of one fuel for another or between fuels and capital and labor represents what in a bottom-up model would be discrete changes from one technology to another.

3. Translating bottom-up information into a top-down specification

3.1 Bottom-up costs

We extract from the bottom-up engineering models the relative cost of electricity from CCS technologies compared to conventional technologies, the thermodynamic efficiency, and the shares of capital, labor, and energy inputs to represent the CCS technologies in EPPA. We base the generation cost and efficiency of CCS technologies on the bottom-up engineering costs as estimated by David and Herzog (2000). Their analysis averages several generation cost studies from the U.S. and Europe of advanced gas and coal generation technologies both with and without carbon capture. Given the cost structure of the CGE model, it proves useful to consider the total unit cost of electricity as the sum of generation (including CO_2 capture), transmission and distribution (T&D), sequestration, and the cost or carbon permits to cover that portion of carbon that is not captured:

$$C_{Electricity} = C_{Generation} + C_{T\&D} + C_{Sequestraton} + kP_{Carbon} \quad (2)$$

where the constant ? is the technology-specific rate of carbon emitted per unit of electricity produced. Formulated as such, Equation 2 makes explicit the dependence of the cost of electricity on the price that must be paid for any carbon that is emitted to the atmosphere by the technology, as even capture technologies cannot capture 100% of the carbon in the fuel.

The generation costs, as described in David and Herzog (2000), are based on known, but more efficient, state-of-the-art, technologies that are limited in use today. We use David and Herzog's (2000) set of cost estimates that assume that small technical improvements are made prior to commercial availability in 2020. These technology-based studies do not include estimates of transmission and distribution (T&D) costs but these must be considered as they are included in other electric technologies within EPPA. T&D costs were derived from U.S. data (U.S. DOE, 1999). Sequestration costs include pipeline transport of the captured CO_2 of up to

500 kilometers, its injection into a reservoir, and other costs related to the disposal site such as monitoring. We use a constant cost of \$36 per metric ton of carbon for the sequestration component of the costs where the carbon is transported and injected into the reservoir as liquid CO_2. This cost estimate is from Herzog (2000). Based on the analysis of David and Herzog (2000), we assume the technologies capture 90% of the carbon content of the fuel input.

Table 2 below presents the total cost of electricity, including T&D costs, but net of emission penalties from the bottom-up data for the three technologies. At natural gas prices of nearly \$3.00 per million Btu, the NGCC technology produces electricity at 55 mills per kilowatt-hour (column 2), 16% less than the average cost of delivered power in the U.S. at 66 mills per kilowatt-hour (DOE, 1995). The gas CCS technology is 8% more expensive than the average cost of delivered power and 28% more expensive than the NGCC technology at 71 mills/kWh. The coal CCS technology, at 82.3 mills/kWh, is 25% more expensive than the average cost of delivered power and carries a 49% premium over the NGCC technology, estimated to be the lowest cost electricity producing technology currently available. Column 3 shows the ratio of the cost of each of these technologies to the average cost of conventional generation, which we refer to as the cost 'mark-up'. The difference between the best available fossil fuel electricity generation option and the current cost of electricity production as represented in the input-output data in National Income and Product Accounts (NIPAs) data, the basis for CGE modeling, is why Biggs (2000) concluded that to accurately represent carbon capture and sequestration one also needs to add the advanced gas technology. The CGE modeling approach assumes that the base year data represents an equilibrium condition, but the incomplete penetration of the advanced gas technology means that the electricity sector was in fact in disequilibrium in the base year. Adding the technology explicitly thus allows us to represent this disequilibrium and simulate the gradual move, over time, toward an equilibrium that includes this technology – depending, of course, on how fuel prices and other factor prices change.

Another important feature of the CCS technologies are thermodynamic efficiencies (column 4), which are approximately 10% less than generation technologies without capture and sequestration. Finally, carbon emissions are much lower for the CCS technologies than for advanced gas generation but because only 90% of the carbon is removed, some emissions remain (column 5). Given these data, Equation 2 can be used to see how, from a partial equilibrium perspective, different generation technologies compare as the price of carbon changes, holding all other input prices constant. In particular, we can compute the carbon price that would be necessary to make the lower emitting technologies just competitive with conventional coal technologies or the advanced gas technology. These estimated break-even carbon prices, as compared with the advanced gas technology, the lowest cost alternative, and pulverized coal, the most ubiquitous conventional technology, are shown in the last column of Table 2. When compared with the advanced gas technology, and at the natural gas prices assumed above, the gas CCS technology becomes competitive at \$190/mtC (metric tons of carbon), half that of the coal capture technology's equivalent price of \$380/mtC. These carbon-equivalent prices drop substantially when the capture technologies are compared to pulverized coal technology, which emits over twice as much carbon as the advanced gas technology at 0.201 kg C/kWh. Evaluated against this technology, the gas CCS technology becomes competitive at \$35/mtC while the coal CCS technology is competitive at prices above \$100/mtC. These differences further emphasize the importance of representing the best-available non-capture fossil technology if one hopes to correctly estimate the potential penetration of CCS technologies.

Table 2 about here

These three technologies differ not only in total costs, but also in the levels of capital, labor, and fuel required to produce a unit of output. The bottom-up engineering cost data for the cost components listed in Equation 2 are categorized as capital, fuel, operations and maintenance, and administrative and general. From these data, we can estimate input shares, and these can be used directly as the CES share parameters (Table 3). These shares of capital and fuel inputs offer insight into how changes in various factor prices affect each technology. The advanced gas technology without capture and sequestration requires the lowest share of capital at 0.49, but the highest share of fuel at 0.30. The addition of the capital intensive CCS technology to an NGCC plant raises the capital share to 0.54 while reducing the fuel share to 0.26 even though capturing and sequestering the CO_2 requires more absolute energy per kWh of electricity produced. Capital represents an even greater input share for the coal capture technology at 0.66. A fuel share of 0.12 reflects both low coal prices and the capital-intensive nature of the technology. The shares of operations, maintenance, general and administrative costs range from 0.20 to 0.22 across the three technologies.

Table 3 about here

3.2 Top-down representation

Having determined the total costs of electricity production, the sources of those costs, thermodynamic efficiencies, and carbon emissions for the new technologies, we translate this bottom-up information into a top-down representation consistent with EPPA's modeling framework outlined in Section 2. We adopt the following conventions in translating the cost categories (capital, operations and maintenance, administrative and general, and fuel) into the factors of production found in EPPA (capital, labor, and energy). Bottom-up capital and fuel costs are respectively treated as inputs of capital and energy. Operations, maintenance, administrative, and general are grouped into labor costs. The shares of each input S_m are used as the A_m in the CES production functions, as depicted in Equation 1, and are based upon the percentage that component contributes to the overall cost of the technology. Having separated out the various cost components, we develop the nesting structure of the CES production functions and subsequently specify substitution elasticities.

As shown in Figure 1 below, the top-level substitution of the production function occurs between the capital-labor-energy bundle and a fixed factor resource. The fixed factor resource represents an endogenously specified production input that serves to limit the rate of penetration of a technology. In the context of large-scale electricity generating technologies, this may be thought of as an initially limited amount of engineering capacity to build and install new plants or a regulatory process that slows installation. The representation of the fixed factor will be discussed at length in Section 5. The capital and labor inputs for generation (X_{Kgen}, X_{Lgen}) and transmission and distribution (X_{Ktd}, X_{Ltd}) are grouped in the value-added bundle. This allows substitution between capital and labor and recognizes that transmission and distribution as well as generation are required to deliver a unit of electricity. The fuel and sequestration bundle consists of three inputs consumed in fixed proportions (substitution elasticity is zero): fuel with sequestered carbon ($X_{Fuel\ ex\ CO2}$), fuel excluding sequestered carbon ($X_{Fuel\ \&\ CO2}$), and a capital-labor bundle specific to sequestration (X_{Kseq}, X_{Lseq}). Ninety percent of the fuel consumed by a generating plant with CCS, $X_{Fuel\ ex\ CO2}$, yields CO_2 that is subsequently sequestered. Consumption of this portion of the fuel is not subject to any carbon penalties. However, the remaining 10% of the fuel input, $X_{Fuel\ \&\ CO2}$, emits CO_2 into the atmosphere that entails carbon penalties if there is a carbon policy in place. The nested structure leads to eight separate inputs for capital, fuel, and labor (Kgen, Lgen, Ktd, Ltd, Fuel & CO_2, Fuel ex. CO_2, Kseq, Lseq).

Figure 1 about here

The values for the various elasticities of substitution are shown in Figure 1. Critical elasticities are those that represent the ability to substitute between fuels and other factors. These elasticities were chosen to assure that the implied thermodynamic efficiency remained within a range that was technologically feasible, even under very high fuel and carbon prices. This consideration is discussed at greater length in Section 4. Consistent with the bottom-up technology information, the input proportions are fixed by the percentage of carbon captured from the fuel, which was established at 90% as described in Section 3. This portion of the fuel input requires capital and labor inputs for pipeline transport and injection of the CO_2. While the non-sequestered fraction of the fuel does not incur sequestration costs, it includes the costs of carbon taxes or shadow prices for releasing CO_2 into the atmosphere. The production structure and elasticities are the same for the advanced gas technology with two exceptions. The capital and labor inputs for sequestration, X_{Kseq} and X_{Lseq}, are both zero and the fuel input consists of only $X_{Fuel\ \&\ CO2}$, which includes any carbon penalties since all of the CO_2 is emitted to the atmosphere.

Having defined a production function with cost share information based on a bottom-up cost model and introduced nesting to allow for input substitution where appropriate, we next specify the total cost of each new technology relative to existing production technologies. To obtain the correct entry condition for the technologies, we multiply each of the input share parameters $A_{m,b}$ in the production function by the 'mark-up' factor M_b found in Table 2, column 3 where the subscript b denotes the technologies identified in Table 2. We use the same M_b, the ratio of new technology cost to fossil fuel-based conventional generation, for all regions.[2]

The input shares $S_{m,b}$ now sum to M_b instead of unity. As indicated in the partial equilibrium analysis, the CCS technologies will not be competitive with conventional or NGCC technologies until changes in input prices increase the costs of the conventional and NGCC technologies. With an M_b of less than unity, the NGCC technology without CCS is cheaper than the conventional technologies and is competitive immediately, given relative fuel prices in the base year.

4. Treatment of thermodynamic efficiency in CES production functions

The concept of thermodynamic efficiency for a power plant is well understood in engineering terms as the ratio of the energy content of the electricity produced to the energy

[2] This assumption works well in most regions with a substantial amount of conventional generation, but may understate the relative costs of the new technologies in regions with low levels of conventional fossil generation such as Brazil and Other OECD Countries (Canada, Australia, New Zealand, Turkey, Norway, Iceland, Switzerland) where hydroelectric power is the main electric technology.

content of the fuel input. One of the key sets of information we can use from engineering studies about the possible future evolution of generation technologies is the prospect (and limits) regarding improvements in this efficiency. EPPA retains physical accounts of fuel use and electricity output and so we are able to compute this ratio as it changes over time and under different policy scenarios. Preliminary analysis demonstrated that it is quite possible, with an exogenous AEEI efficiency trend combined with substitution elasticities typical of the econometric literature, to have a ratio of energy used to electricity produced in physical units (e.g., exajoules) that eventually exceeds 1.0 when fuel prices are high, violating the basic laws of thermodynamics. In addition to constraining future simulations, it also turns out that the thermodynamic efficiencies help to us to adjust the production function parameters for different regions. To describe how this was done requires that we discuss in greater detail the relationship between the physical energy accounts and the economic accounts in EPPA.

The physical energy accounts as represented in EPPA are supplementary to the economic data that determine the model solution. The economic data uses aggregate sectors, based on National Income and Product Account (NIPA) data, where the aggregate is based on the economic principle that prices are used to weight heterogeneous goods that make up the aggregate. For example, our sector of refined oil products is an aggregation of a variety of products from petroleum refining including, for example, jet fuel, gasoline, diesel, and residual oil. Similarly, coal consumption is an aggregate of different grades of coal, with each grade or type of coal having a potentially different energy and carbon content and a different price. Higher valued products have larger weights in the aggregation so that the quantity index so calculated does not have a direct interpretation in physical energy units such as BTUs or exajoules, unless one can go back to the underlying price and quantity data. Often these data are based on expenditures or sales and so there is no separate price and quantity data at the level that is typically used in engineering cost studies. The supplementary physical data on fuel use, developed in GTAP to be consistent with the aggregate economic accounts in the base year, allows us, however, to calculate physical use of energy in simulations based on the economic indices of quantity that are simulated in the model. [3]

The relationship of EPPA-based data, the base year price of fuels in physical energy values ($/EJ), and thermodynamic efficiency is described in Equation 3.

$$\frac{E_{elec,b,r}}{E_{fuel,b,r}} = \frac{Y_{elec,b,r}\dfrac{1}{p^{*}_{elec,r}}}{X_{fuel,b,r}\dfrac{1}{p^{*}_{fuel,r}}S_{fuel,b,r}M_{b}} \tag{3}$$

The left side of the equation is the thermodynamic efficiency for technology b in region r, the energy content of electricity output $E_{elec,b,r}$ divided by the energy content of the fuel input $E_{fuel,b,r}$. The right hand side is the corresponding calculation that is needed to get this ratio from the economic data used in EPPA, where

$Y_{elec,b,r}$ is quantity of output of electricity (a dollar-weighted index),

$p^*_{elec,r}$ is an average price of electricity constructed so that the supplementary physical data are consistent with the economic data base,

$X_{fuel,b,r}$ is the fuel input in a dollar-weighted index,

$p^*_{fuel,r}$ is the corresponding price of the fuel in the base year,

$S_{fuel,b,r}$ is the production share of fuel, and

M_b is the mark-up ratio from Table2.

[3] The aggregation is defined for the base year, and the weights remain unchanged in future simulations as, having once aggregated to this level, the model solution provides no information on how these weights change in the future. This physical quantity index is the value of fuel use in the base year under the normalization that prices are equal to 1.0. Prices diverge from 1.0 in simulations but the underlying prices used in the aggregation do not change and so the correspondence to the physical index of energy use remains.

For technologies in use in the base year, and given the assumptions that the base year data reflects an equilibrium and that output of electricity from different technologies are perfect substitutes, M_b=1.0.

For simulations of future conditions under reference or policy situations, the model simulates new values for Y, X, and price indices for each input reflecting real changes in factor prices over time and across policy cases. Thus thermodynamic efficiency can be estimated from the economic data over time for existing technologies and for new, and currently unused, technologies such as the CCS technology.

The ability to check on the implied thermodynamic efficiency proved useful in evaluating the reasonableness of future projections of the model, in comparison with technological potential as previously discussed. It also proved useful in our initial calibration of regional costs, as we used cost data primarily from U.S.- and EC-based studies of these technologies. Such a simplifying assumption, that a 'best available technology' would be available worldwide, is not uncommon in either top-down or bottom-up modeling approaches. Given that large firms with a multinational presence are developing the technologies this assumption seems reasonable. The cost share data depend, however, not only on the technology characteristics but also on the prevailing prices for the various inputs. Here we faced the difficulty that, for most of the inputs, we did not have separate price and quantity data for each region for the detailed engineering estimates that was consistent with the NIPA-type data in the GTAP base year data. To correct for these differences at the engineering cost level would literally require a re-estimate of the engineering costs in terms of the price of all the items that would go into building the facility (concrete, steel, labor, siting) and running it (fuel and other operating expenses), item by item.

To use Equation 3 to make a correction for regional differences in costs, we set the cost share of fuel, $S_{fuel,b,r}$, given the regions price for the fuel, $p_{fuel,r}$, such that thermodynamic efficiency of the technology based on our engineering data and assumption of a globally available technology was met, proportionally adjusting the cost share of other inputs as necessary so that the share total summed to unity. Incorporating the above methodologies into a CES production function yields the generalized form in Equation 4.

$$Y_{elec,b,r} = \left[M_b A_{1,b,r} X_{1,b,r}{}^{r} + \ldots + M_b A_{n,b,r} X_{n,b,r}{}^{r} \right]^{1/r} \tag{4}$$

These regional adjustments turned out to be quite important in some cases. Opposite extremes were witnessed in Japan and the Former Soviet Union. The ratio of Japan's electricity to fuel price in the GTAP data is much higher than in other regions, implying much higher non-fuel input costs for current generation, even with relatively high fuel prices in Japan.[4] Therefore, for the new technologies introduced for this analysis, using the fuel cost share based on our engineering data implied a thermodynamic efficiency approaching 15%. The situation was the opposite in the FSU, which the GTAP data shows a very low electricity price implying that the cost share of other inputs was much lower than in other regions. Using the fuel cost share based on the engineering data implied a thermodynamic efficiency approaching 70%. We interpret these regional differences in the cost share of other inputs in current generation to represent regional differences in, for example, regulation (and the requirements it places in the technology) and in prices of other inputs. By adjusting the fuel shares for each region so that the thermodynamic efficiencies, as calculated using Equation 3, are consistent with the engineering data presented in Table 2 (i.e. 44% to 60%), and with a constant mark-up across regions, we implicitly assume that regional cost factors causing differences in existing electricity generation technologies will also affect the cost structure of these new technologies.

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[4] Under the assumption of a constant returns to scale technology, and initial equilibrium, CGE models like EPPA require that marginal cost equals average cost equals output price in the base data, except as we have altered this for the new technologies with the factor M_b. A region with relatively high electricity price compared with the fuel price, given similar technological efficiency, implies that the cost share for other inputs is much higher for that region than for most regions.

5. Control of technology penetration rates

Evidence that a new technology takes over a market gradually, where the share of the market controlled by the technology plotted against time follows some type of S-shaped function, is widely observed (Geroski, 2000). There are many reasons cited for such gradual penetration. For example, long-lived capital in the old technology may only be replaced with the new technology as the old physically depreciates. In EPPA, the vintaging of capital, discussed in the next section, captures this process explicitly. But other processes also slow penetration. In the investment literature many of these are often grouped under the concept of adjustment costs that occur with rapid expansion (e.g., Hayashi, 1982). At the engineering cost level, such adjustment costs may reflect the need to gradually develop an industry with sufficient specialized engineering resources and the necessary equipment to install new capacity. Penetration may be also be slowed by regulatory approval processes.[5] Such limits increase the cost, and slow the penetration. In the absence of a specific representation of these processes, the rate of penetration of a constant returns to scale technology modeled in a CGE model like EPPA can be unrealistically rapid.

An approach for representing the penetration process, that is theoretically consistent with CGE modeling, is to explicitly introduce an additional quasi-fixed factor in the production function, specific to the new technology, whose endowment in the economy is initially quite

[5] Another set of factors that contributes to slow penetration are grouped under the concept of 'learning'. Learning—that may occur in the regulatory process, in engineering firms constructing the plants, and in the companies purchasing and running plants—improves cost and performance, and therefore increases competitiveness and the rate market penetration. Often the concept of learning and adjustment cost are seen as opposing, adjustment costs raise the cost of the technology and learning leads to lower costs. Some of the main differences may be due largely to the perspective from which the process is observed. In the adjustment cost case, a long-run low cost is identified but adjustment costs explain why that low cost may not be achieved if rapid deployment is required (e.g., lack of experience of engineering companies). Learning instead focuses on a current high cost of a first few installations, and based on this information, identifies reasons that costs may fall (e.g., learning by engineering companies of how to construct the plants more efficiently).

limited.[6] This was represented in Figure 1 by the top nested fixed factor, where the factor share is set at 1%. The price of the fixed factor and annual rents are determined endogenously, depending on its quantity relative to demand for the technology, and the rents accrue to the representative consumer. As modeled, the fixed factor resource endowment is initially limited but grows as a function of the technology's output. In the context of large-scale electricity generating technologies, this fixed factor may be thought of as engineering capacity to build and install new plants that is initially limited but that increases in availability as the technology moves from the pilot plant stage to viable market competition. We posit a functional form that produces an S-shaped (sigmoid) growth as a function of output as shown in Equation 5, where the technology specific subscript *b* has been dropped from each term of the equation for simplicity.

$$FF_r = aY_r^{g} + lY_r^{V} \tag{5}$$

We consider the penetration rate of an analogous large-scale electric generating technology – nuclear power—to parameterize growth of the fixed factor. During the rapid growth of nuclear power in the U.S., the share of nuclear power expanded by up to 45% per year in the early 1970's dropping to 9% per year in the 1980's. We parameterize Equation 5 to limit the share growth of the new technologies to roughly mimic that of nuclear power under a carbon tax of $200/mtC. As long as output is growing, the endowment of fixed factor grows more than proportionally, and so the fixed factor becomes less scarce, rents fall, and in the long run it does not restrict the ultimate penetration of the technology. The partial equilibrium costs we specified in Table 1 are achieved when the demand for a technology's output balances the simulated price of the fixed factor. The first term in Equation 5 is approximately linear with ? = 0.8 to 0.9. This

[6] This general approach is applied to other backstop technologies in EPPA. Much of the adjustment cost literature and evidence on slow penetration is based on partial equilibrium concepts, or describes statistical or econometric estimates where the processes are suggested rather than explicitly addressed. This empirical evidence can be quite useful in parameterizing our penetration structure but this does not provide a theoretically consistent approach for CGE modeling.

term governs the growth of the fixed factor at low levels of output Y_r as a >> ?. The second term accelerates fixed factor growth at high levels of output with ? = 2.0 to 2.4.

6. Capital stock vintaging

As examined in Jacoby and Sue-Wing (1999) and as described in detail in Babiker *et al.* (2001), the EPPA model includes explicit vintaging of capital stock to capture the irreversible nature of physical capital investments. As used in the standard EPPA, substitution as described by the production function parameters, such as those in Figure 1, apply only to a malleable portion of the capital stock. Malleable capital in any period includes new investment and portion (1-q) of the previous periods investments, remaining after depreciation, that is assumed to remain flexible. This representation allows for partial retrofit or redeployment of existing capital, while retaining the idea that there is not complete flexibility to reconfigure older vintages of physical capital. The vintaged portion of investment (q) takes on a Leontief production structure for all inputs (Figure 2), frozen at the factor shares that actually were simulated in the period in which it was put in place. For period t, and suppressing the technology subscript, the factor share parameters $A_{m,t}$, m=1, n are updated to equal the $S_{m,t-1}$ simulated in period t-1 and the production structure is redefined as fixed coefficient i.e., with elasticities of substitution all equal to zero.

As evidenced in Section 3, fossil fuel electric generating technologies are highly capital intensive. Thus, the vintaging approach used in other sectors of EPPA was adapted and applied to the new technologies we introduced. As will be shown in the results section, depending on the reference and policy case conditions, it becomes economically desirable to switch from one new technology to another as relative prices for carbon and fuels, and other conditions, change. Representing the irreversibility of investment (its long capital life) as an explicitly vintaged capital stock, means that a large investment in advanced gas technology in period t, cannot be redeployed or reconfigured as a coal plant with CCS in period t+1. Once vintaged capacity is put in place, it remains until it fully depreciates.

Figure 2 about here

The vintaged portion of the capital follows the standard EPPA formulation, where four vintages are defined. A difference as applied for these technologies from the approach elsewhere in EPPA, is that the (1-q) malleable portion of the stock from previous periods remains specific to the technology. In the standard EPPA the malleable portion can, in principle, be redeployed anywhere in the economy. This revised specification as applied to the three new technologies creates, in addition to the four new vintages of capital in each technology, three new distinct malleable capital stocks that are specific to these new technologies. Given EPPA's 5-year time step, this vintaging structure means that capital has a lifetime of 25 years, five years as malleable capital when it is new investment and the following 20 years as either vintaged capital or sector-specific malleable capital.

The evolution of capital over time is implemented in a set of dynamic equations. Malleable capital $K^m_{b,r,t+1}$ for technology b in region r for period t+1 is comprised of new investment in the technology, $I_{b,r,t+1}$, plus the stock of capital invested in period t remaining after depreciation that also remains malleable where (1-d) is the fraction of capital that has not been depreciated.

$$K^m_{b,r,t+1} = I_{b,r,t+1} + (1-d)K^m_{b,r,t} \quad (6)$$

Rigid capital in period t+1 is comprised of the stock of capital invested in period t remaining after depreciation with fixed input share parameters.

$$K^r_{b,r,t+1,v} = q(1-d)I_{b,r,t} \quad \text{for ? = 1} \quad (7)$$

The quantity of rigid capital in subsequent periods undergoes depreciation.

$$K^r_{b,r,t+1,v} = (1-d)K^r_{b,r,t,v-1} \quad \text{for ? = 2, 3, 4} \quad (8)$$

We made the malleable capital technology-specific for these new technologies because, in reality, it is difficult to imagine that very much of the capital stock (e.g., turbines and pipelines) could be feasibly redeployed elsewhere in the economy. For the other sectors in EPPA, the assumption is that the malleable capital stock consists of structures, vehicles, and other such equipment that could be redeployed. These representations are simplifications of the complex process of capital stock turnover, but become necessary to limit the number of distinct capital stocks and maintain the computational feasibility of the model.

7. Scenarios and results

Using the methodology described above, we analyze the global adoption of CCS technologies under three policy scenarios as outlined in Table 4. They were designed to illustrate the potential of carbon sequestration under widely different future conditions, and our use of them in no way indicates an endorsement of any of them. The first scenario is a reference scenario where it is assumed that there are no constraints on greenhouse gas (GHG) emissions. In the second scenario, an initial tax of $50 per metric ton ($/mtC) is placed on all regions beginning in 2010. The tax increases by $25/mtC in every five-year period and reaches a maximum of $200/mtC by 2040. The tax applies only to carbon dioxide, excluding other GHG's from the tax. The third scenario is consistent with stabilization of CO_2 concentrations at approximately 550 parts per million sometime after the year 2100, when simulated through the MIT Integrated Global System Model (IGSM) under reference assumptions regarding the parameters of the IGSM (Reilly, et al., 1999). The time profile of emissions reduction was defined by an emissions intensity target, in terms of all GHGs, similar to the target proposed by the Bush Administration but applied to all regions and gradually tightened over time. The concept of a tightening intensity target, compared with a constant target, was conceptually described by the Bush Administration

(Bush, 2002) but the specific emissions intensity targets beyond 2010 were not defined in that document. The concentration stabilization scenario places restrictions on both CO_2 and other GHG's by reducing the emissions intensity, or ratio of CO_2 equivalent emissions to gross domestic product, in each region.[7]

This scenario is implemented in the model through a GHG quota. Emission quotas are established in each region that corresponds to an 18% emissions intensity reduction from 2000 to 2010 from 2000 as suggested by the Bush Administration. Quotas in subsequent periods, E_{t+1}, are calculated from the product of an emissions intensity reduction factor $\Re_t$, the previous period's emissions intensity e_t/G_t, and the expected gross national product (GNP) G_{t+1} as shown in Equation 9. Expected GNP is approximated as the product of G_t, the current GNP and G_t/G_{t-1}, the ratio of current GNP over the previous period's GNP. The emissions intensity reduction factor $\Re_t$ begins at 18% in 2015 and reaches a minimum of 26% by 2030. Trading is allowed among gases and regions.

$$E_{t+1} = \Re_t \left(\frac{e_t}{G_t} \right) G_{t+1} \cong \Re_t e_t \frac{G_t}{G_{t-1}} \qquad (9)$$

The resulting emissions paths and carbon prices are presented below followed by an analysis of global CCS technology adoption for the three scenarios. Additionally, we evaluate the effects of alternative assumptions on the treatment of capital vintaging and malleability.

Table 4 about here

7.1 Aggregate Economic and Emissions Results

[7] The stabilization at approximately 550 ppm is in terms of CO_2 alone. Because there are controls on other gases, their concentrations are also lower than in the reference. We do not try to state this as a target in CO_2 equivlent ppm as that does not make much sense, because GWP's, the basis for CO_2 equivalent, integrate radiative forcing over time whereas a concentration exists at a given point in time. CH_4 concentrations, the second most important anthropogenic contributor to warming after CO_2, are lower in 2100 than they are currently under these control scenarios.

While both policy scenarios significantly decrease emissions versus the reference case, emissions diverge greatly after 2030. Under the tax scenario, global GHG emissions remain relatively flat from 2010 through 2025 when the percentage increase in the carbon tax is the highest as shown in Figure 4. Emissions growth increases in 2030 and accelerates after 2040 when the carbon tax has reached its maximum level. By 2100, the tax scenario reduces emissions by 37% from reference. The CO_2 concentration stabilization scenario, based on reductions in emissions intensity, experiences climbing aggregate emission through 2025 as economic growth outpaces emissions growth to meet the emissions intensity targets. After 2025, annual global emissions decline by 3-4% per period and reach 1995 levels by 2085. This emissions path generates a CO_2 concentration of approximately 530 ppm of CO_2 by 2100 on a path that is consistent with stabilizing concentration around 550 ppm sometime thereafter.

Figure 3 about here

The low emissions in the stabilization scenario bring about implicit carbon-equivalent prices ($/mtC$_{eq}$) that rise exponentially from a few dollars in 2030 to $1600/mtC$_{eq}$ by 2100 with the use of CCS technologies. The importance of CCS technologies in cost effectively meeting the intensity targets becomes evident when compared to a stabilization scenario with no CCS technologies. Carbon-equivalent prices under the latter scenario increase by 33% to nearly $1900/mtC$_{eq}$ in 2100 as depicted in Figure 4. The rapid rise of carbon prices, in excess of $400/mtC$_{eq}$ after 2050, result from rising fossil fuel demand in industry and transportation that lack explicit low-carbon emitting technology options such as CCS.

Figure 4 about here

7.2 Electricity Sector Results

The additions to the EPPA model on which we focused in this paper involved electricity generation technologies. We, therefore, provide detail on how these technologies enter into the electric sector under the reference and policy cases. In the reference scenario, total electricity production expands nearly five-fold to 64 trillion kilowatt-hours by 2100. Conventional technologies, which are primarily coal-based, predominate other forms of generation, accounting for 78% of total production from 2060 to 2100. The advanced gas technology expands to a maximum share of 18% by 2020, however rising natural gas prices reduce this share to 4% by 2050. Nuclear power generation changes very little as expansion of capacity is limited by a fixed factor whose growth is severely limited. The limited growth of the fixed factor represents regulatory limits to the expansion of nuclear power capacity. Limited penetration of carbon-wind and solar reflects the fact that they are modeled as imperfect substitutes for electricity from other generation sources. This treatment reflects the fact that they are intermittent, and could only penetrate further with investments in storage, redundant capacity, or through use of a reliable back-up technology.

Figure 5 about here

In the tax scenario, aggregate electricity generation drops only 11% from reference levels by 2100, but the mix of generation technologies changes dramatically. Similar to the reference case, the advanced gas technology accounts for 15% of total electricity generation by 2020. The gas and coal CCS technologies enter the market in 2020 at a carbon price of \$100/mtC. The CCS technologies enter into production at or above the partial equilibrium carbon prices calculated from Equation 2 above for conventional pulverized coal technology yet well below the equivalent carbon prices for the advanced gas technology. Greater displacement of generation from conventional technology by the advanced gas technology would raise the carbon entry price, however limits on the penetration rate of the advanced gas technology inhibit this effect. Gas CCS generation reaches 4.5 trillion kWh by 2040, 16% of total generation. The coal CCS technology penetrates more slowly with only a 7% share by this time. Subsequently, rising natural gas prices lead to a decline in both gas technologies. Growth in the coal CCS technology then expands rapidly to surpass conventional fossil fuel technologies as the dominant form of generation by 2075 and accounts for 50% of total generation by 2100.

Figure 6 about here

All regions except the European Economic Community (EEC) and Japan exhibit a consistent technology adoption pattern of introducing the gas technologies first and switching to the coal CCS technology in response to rising gas prices. In the EEC, base-year electricity prices 30% above the global average explain the lack of CCS adoption. The use of a lower electricity price to define the mark-up ratio M_b inflates the mark-up for this region in particular and thus limits the adoption of the CCS technologies. In Japan, the adjustment made to the fuel factor share for advanced gas $S_{gas,ngcc,JPN}$ as discussed in to Section 5 increases its adoption of the advanced gas without capture technology. This adjustment leads to a fuel factor share parameter of only 0.05. Thus, the competitiveness of the technology is much less affected by rising natural gas prices than in other regions where the gas cost share parameter is much higher.

Under the CO_2 stabilization scenario, the CCS technology adoption pattern is broadly similar to the tax scenario, but with more dramatic changes in the mix of generating technologies. The stabilization scenario does not restrict greenhouse emissions until 2035 as economic growth reduces emissions intensities to target levels. After 2025, implicit carbon prices increase rapidly as greenhouse gas emissions are constrained to meet intensity targets. As in the reference scenario, the advanced gas technology expands to account for 4 trillion kWh, a fifth of total generation, by 2020. However, the rapidly rising carbon price allows this technology to expand to nearly 7 trillion kWh by 2040. The coal CCS technology enters in 2040 at carbon prices of \$100/mtC_{eq}. This technology gradually displaces the advanced gas and conventional generating technologies and generates over half all electricity produced by 2070 as shown in Figure 7. The gas CCS technology also enters in 2040, but accounts for a maximum of 5% of global generation and does not account for a significant share of production in any region except Japan. Fixed factor scarcity for the coal CCS technology constrains its penetration and allows the gas CCS technology to compete. Rising gas prices lead to declining production from gas-based technologies beyond 2050. All regions except Japan generate a portion of their electricity with the coal capture technology by 2060. As in the tax case, Japan generates the majority of its electricity using the gas without capture technology as described in Section 7.1 above.

Figure 7 about here

A comparison of greenhouse gas stabilization scenarios with and without CCS technologies illustrates the potential effect of these technologies on electricity generation and economic welfare, measured as equivalent variation.[8] Including CCS technologies in the model, global electricity production reaches 50 trillion kilowatt-hours in 2100 compared with only 36 trillion kilowatt-hours without CCS technologies, a 38% increase in generation. The additional electricity output and lower carbon prices due to the widespread adoption of the coal capture technology improve welfare in all regions except Brazil, which relies heavily on hydropower, and so carbon sequestration is of little value there. By 2100 annual welfare improvements in China, India, and Eastern Europe exceed 3%. Annex B regions exhibit annual welfare improvements between 0.4% and 1.4% in this period.

7.3 Sensitivity Analysis

We evaluated many different scenarios and sensitivities, the most interesting of which was the treatment of capital vintaging. Vintaging affects both the initial penetration rate of a new technology when they become competitive and their decline when they become less competitive than other technologies. To examine the importance of this feature of the model we compare three cases: 1) complete capital malleability across all technologies and sectors, 2) technology/sector specific capital but with malleability of capital within a specific technology,

[8] Equivalent variation is the preferred measure of economic impact. To convert these to an absolute dollar amount, one would multiply the percentage change by aggregate consumption for the economy, and so these savings are substantial.

and 3) the specification as presented in Section 6 that included vintaged and sector-specific capital. We report results from the reference scenario, with no emission penalties, and focus on the advanced gas technology.

With complete capital malleability across technologies and sectors, the advanced gas technology exhibits greater penetration and more rapid exit versus the reference scenario previously discussed. Generation from the advanced gas technology grows to 5.7 trillion kWh, or 26% of total electricity generation, by 2020 as shown in Figure 8. By 2040, however, rising natural gas prices reduce the output from this technology over 60% to 2 trillion kWh. The maximum single-period decline in advanced gas generation reaches 40% from 2030 to 2035. Without limitations on capital mobility, once the advanced gas technology becomes uneconomic, the capital is redeployed in other economic sectors.

Figure 8 about here

Treating capital as a technology-specific investment raises the maximum level of penetration and slows the decline witnessed in the above case. In this second case, capital invested in the advanced gas technology cannot be redeployed to other sectors yet the capital remains malleable subject to the nested production structure in Figure 1. Generation from this technology peaks in 2025 at nearly 7 trillion kWh, or 20% above that in the previous case. Use of the technology-specific capital stock explains the higher peak production. Lacking an alternative use, the price of the malleable, technology-specific capital stock remains below that of the non-sector-specific capital and thus encourages continued investment in the advanced gas technology. After 2025, rising gas prices lead to declining output from advanced gas generation. However, use of the technology-specific capital stock yields a more gradual drop in output than in the previous case.

Finally, we turn to the case of technology-specific vintaged capital described in Section 6. Recall that in addition to restricting the redeployment of invested capital, a fraction f of the invested capital, where f = 0.8, becomes rigid with fixed input shares as defined in the initial period of investment. This vintaged representation reduces the maximum generation of the advanced gas technology by 46% from the second case. The fixed share parameters of the vintaged capital prohibit input substitution in the vintaged capital stock. Unable to utilize less expensive capital and labor input, the advanced gas generation is limited to only 3.7 trillion kWh by 2035 due to rising natural gas prices. Again the technology's output gradually declines reflecting the depreciation of the technology-specific capital stock.

8. CONCLUSIONS

We described a consistent method for integrating bottom-up engineering data on new technology into the EPPA model, a top-down CGE model. We presented the link between the production function representation of a technology and its thermodynamic efficiency. This allowed us to parameterize the production function to reflect regional differences and to better constrain elasticities of substitution to assure that limits to thermodynamic efficiency were not exceeded, and instead reflected engineering estimates of feasible potential. We also developed and parameterized model components to represent market penetration, and eventual exit, of technologies as their competitiveness changes. It is a pattern of market penetration that is often observed for such technologies. This result was achieved while retaining consistency with theoretical underpinnings of a CGE modeling framework.

In developing an approach for incorporating bottom-up information into the EPPA model, we applied it to the electricity sector where we add three new large-scale technologies that could contribute to meeting a carbon constraint. These were an advanced gas generation technology without carbon capture and sequestration (CCS), advanced gas with CCS, and an advanced coal technology with CCS. The advanced gas technology was less costly than the pulverized coal generation and so, even without constraints on carbon emissions, this technology penetrated. Its success in the market was of limited duration because rising gas prices meant that eventually it could not economically compete. It played a slightly larger role when carbon constraints were present, but was again limited by rising gas prices. The CCS technologies could play a substantial role in reducing carbon emissions, but they would only be economically viable with policy constraints on carbon dioxide emissions. However, the carbon price at which CCS technologies entered was much lower than would be expected given a partial equilibrium comparison of them with today's best available technology, the advanced gas technology, because of the rising price of gas.

Our underlying assessment of the cost of CCS technologies is based on the technology as it exists today with only modest improvements. There are large research projects in industry and in the U.S. government with the aim of greatly advancing the technology and lowering its costs even further, and if these are successful then CCS could enter at lower carbon prices than found in our simulations. We find, however, that the CCS does not provide a backstop cost for a carbon policy if, as we have modeled it, it is limited to electric generation technologies. This is because even at the costs we specify for CCS, it is competitive with nearly all fossil electric generation by 2100, so that the carbon price depends on marginal costs of abatement elsewhere in the economy. The coal CCS technology offers the most cost effective long-term source of low carbon emitting electricity, as the gas technologies are limited by gas resource availability reflected in high gas prices that make the technology non-competitive. Benefits of using the CCS technologies are seen through increased electricity production and lower electricity prices, and this is reflected in lower welfare costs of the climate policy in most regions. The availability of CCS technologies in the policy scenarios raises the demand for gas and coal resources versus policy scenarios without the CCS technologies.

The two policy cases we investigated illustrate that the timing and ultimate penetration of the CCS technology depend on specifically how climate policy is formulated, and this is a major uncertainty in forecasting when CCS will be implemented at a significant level. As with any projection, there are many uncertainties including the potential for technological improvements in CCS technologies. Also, the uncertainties that go into creating a reference forecast in the EPPA model include the specification of fossil fuel resources that directly determines future fuel prices, the level of economic growth, energy efficiency improvement in the economy, and the other mitigation options available in the electric sector and in the economy in general.

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Table 1. EPPA regions, sectors, and factors of production

Regions	Annex B (United States, Japan, European Community, Other OECD, Eastern European Associates, Former Soviet Union) and Non-Annex B (Brazil, China, India, Energy Exporting Countries, Dynamic Asian Economies, and Rest of World).
Production Sectors	Coal, Oil, Refined Oil, Gas, Electricity, Energy Intensive Industries, Agriculture, Investment, and Other Industries.
Primary Factors	Labor, Capital, and Fixed Factor resources for coal, oil, gas, shale oil, and agriculture.

Table 2. Technology costs, including transmission and distribution costs

Technology	Total Electricity Cost Net of Emissions Cost (mills/kWh)	Cost Ratio of CCS to Conventional Technology (*Mark-up*)	Thermo-dynamic Efficiency	Emissions Constant ? (kg C/kWh)	Carbon Entry Price for CCS vs. NGCC, Pulverized Coal ($/mtC)
Advanced Gas (NGCC)	55.3	0.84	60%	0.092	NA
Gas (CCS	71.0	1.08	54%	0.010	$190 / $35
Coal CCS	82.3	1.25	44%	0.020	$380 / $100

Table 3
Share of total cost by cost category and technology

	Cost Category		
Technology	Capital	O&M, G&A	Fuel
Advanced Gas (NGCC)	0.49	0.21	0.30
Gas CCS	0.54	0.20	0.26
Coal CCS	0.66	0.22	0.12

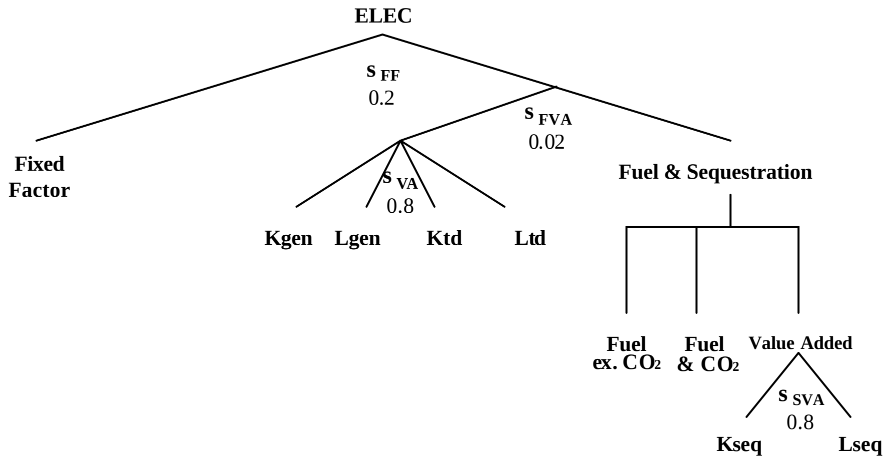

Figure 1 CES nesting structure for CCS technologies

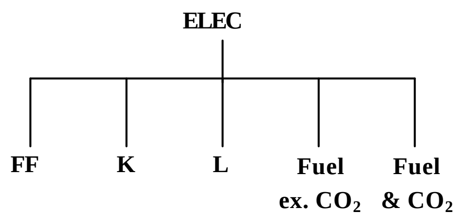

Figure 2 Production function for rigid, vintaged capital

Table 4
Description of policy scenarios

Scenario	Description
Reference	No greenhouse gas constraints in any regions.
Carbon Tax	In 2010, a $50 per ton tax is placed on carbon. The tax increases by $25 every five years reaching a maximum of $200 per ton carbon by 2040. Other greenhouse gases are not taxed.
Greenhouse Gas Concentration Stabilization	Greenhouse gas concentrations are stabilized at 550 ppm shortly after 2100. Greenhouse gas emissions intensity is reduced by 18% from 2000 to 2010. Thereafter, emissions intensity is reduced by 12%, on average, every period. Trading is allowed between countries and across gases.

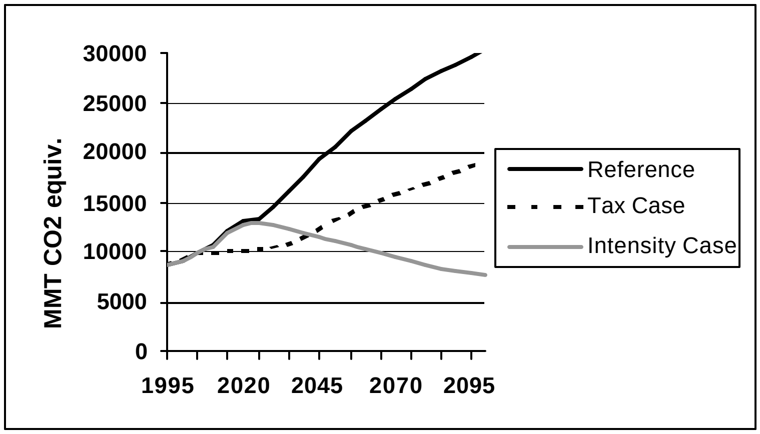

Figure 3 Annual greenhouse gas emissions for three scenarios

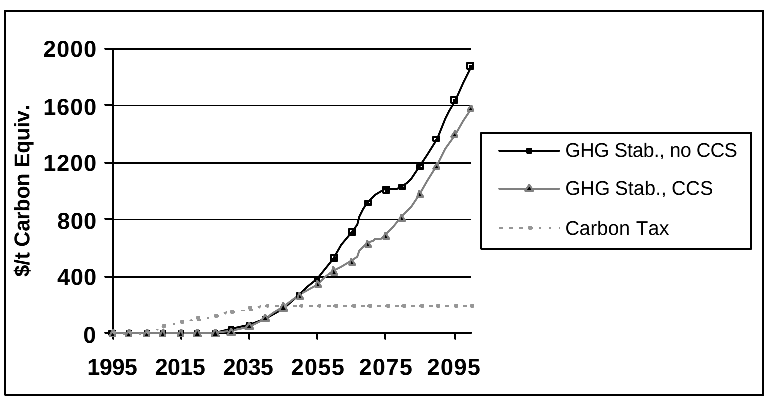

Figure 4 Carbon-equivalent prices under three policy scenarios

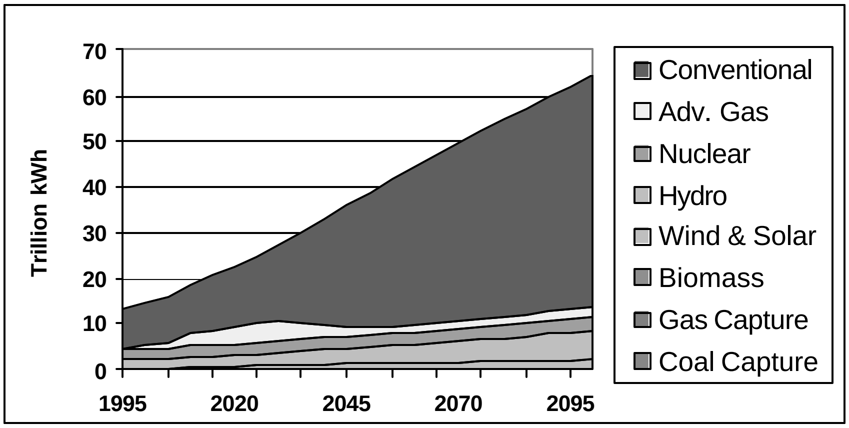

Figure 5 Global electricity production – reference scenario

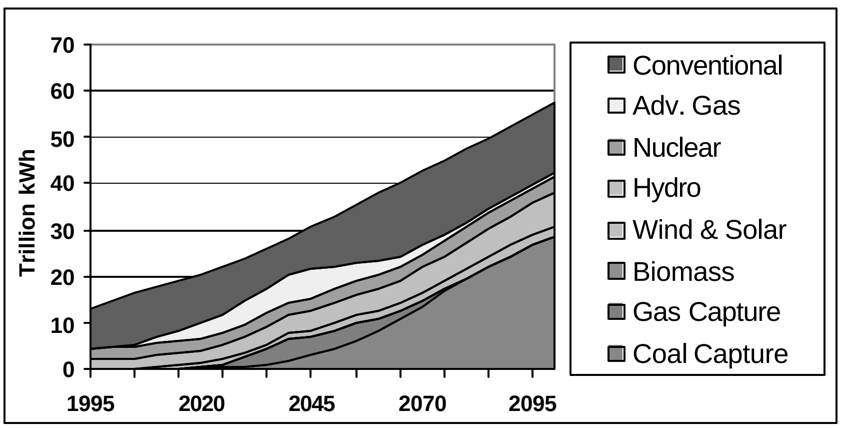

Figure 6 Global electricity production – tax scenario

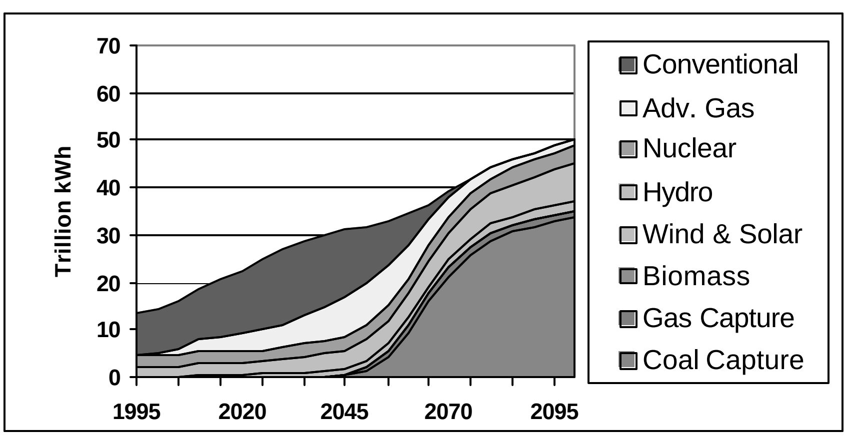

Figure 7 Global electricity production – stabilization scenario

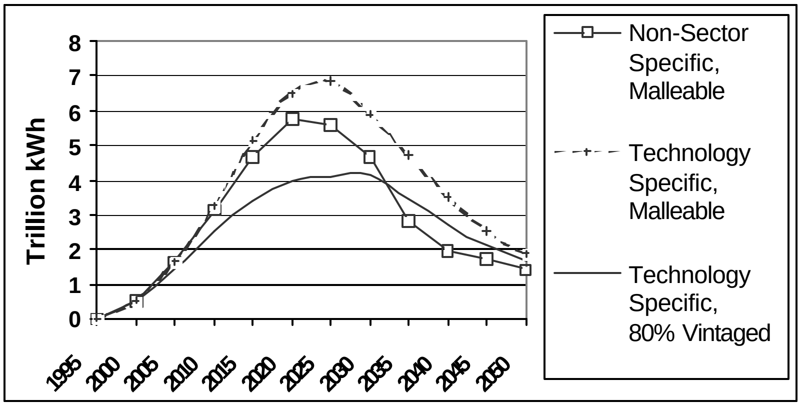

Figure 8 Effects of vintaging and malleability on advanced gas generation