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Modelling of the future of transport fuels in Australia

A report to the Future Fuels Forum

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INTRODUCTION

The Future Fuels Forum is exploring challenges arising from plausible scenarios for the future of transport fuels in Australia. A key objective of the project was for the deliberations of the Future Fuels Forum to be supported by quantitative analysis of the scenarios that were developed. The process of exposing the scenarios to quantitative analysis influenced the formulation of the scenarios by helping to determine the relative importance of different scenario drivers and their assumed future states. Conversely the interaction of the modelling team with the scenario developers assisted in improving various aspects of the quantitative model.

This report provides the technical detail behind the projections presented in the report *Fuel for thought* (CSIRO and Future Fuels Forum, 2008). It describes the modelling framework that was applied, the scenario and model assumptions that were used to underpin the modelling and the detailed model results associated with each scenario examined. The report contains results for a number of sensitivity cases not discussed in detail in *Fuel for thought.* While the core drivers of the main scenarios are greenhouse gas emissions trading and changes in international oil supply, the sensitivity cases address uncertainty around social preferences for travel, additional policies that might be considered by governments and technological uncertainty in regard to biofuels, hydrogen, nuclear power and CO_2 capture and storage.

Besides providing additional detail on modelling results the purpose of the report is to make the assumptions of the modelling framework and underpinning data more transparent. The model that is employed for this report is CSIRO's Energy Sector Model (ESM). It is a partial equilibrium model of the Australian energy sector including a detailed transport sector representation. It was co-developed by CSIRO and the Australian Bureau of Agricultural and Resource Economics (ABARE) in 2006. Since that time CSIRO has significantly modified and expanded ESM. Like all models, ESM has specific strengths and limitations which are discussed in detail in this report.

MODELLING FRAMEWORK

Alternative modelling frameworks

The modelling presented in this report was undertaken for the purposes of providing quantitative analysis of scenarios developed by the Future Fuels Forum whose goal is to explore plausible scenarios for the future of transport fuels in Australia and consider the challenges arsing from them. In that context it was clear that the model employed needed to have the following features:

- A detailed representation of the transport sector including:
    - Conventional and alternative fuel supply
    - The vehicle fleet
    - Alternative vehicle engine technologies
    - The scale of demand in each of the major transport modes and their major determinants.
- The ability to simulate out into the long term future but in time steps that were not too great to ignore short term issues of interest

Additional features considered desirable were the ability to calculate pricing and economic impacts, greenhouse gas and criteria pollutant emission accounting and calculation of land use change. With these features the model would be able to quantify the environmental and economic impact of each scenario and provide some indication of social impacts in so far as they are related to the affordability of transport.

An economic framework underpinned by detailed technological representation of alternative fuels and vehicles would satisfy most of the criteria outlined above. However, given economic models solve as systems of simultaneous equations they generally do not represent detailed spatial information such as local transport networks and land use patterns. Tracking the stock and usage patterns for many individual items of infrastructure and land across Australia would make the model too computationally and structurally large to be practical. Instead, economic models of the transport sector that have national coverage generally only track the stock of transport vehicles. The influence of other transport infrastructure is captured in the realised efficiency with which the vehicle stock is able to carry out its task.

Economic models which represent a single market or sector are called partial equilibrium models. A partial equilibrium model seeks to determine the market equilibrium conditions for one sector of the economy (e.g. in this case the energy and transport sector) holding all else constant. Relative to other economic models, this approach presents both strengths and limitations.

The main limitation, as the name suggests, is that partial equilibrium models provide only a partial picture of the total impact of the scenario being explored on the national economy. The alternative is to use a general equilibrium model which models every sector in the economy simultaneously. However, the limitation of a general equilibrium model is that each sector of the economy is only modelled in a highly aggregated sense. For example, most general equilibrium models only examine a limited range of alternative fuels, do not track the vehicle fleet at all and generalise the effect of alternative engines and vehicle sizes via assumptions about changes in fuel efficiency.

To overcome the limitations of partial and general equilibrium modelling approaches it is possible to interface partial and general equilibrium models iteratively to achieve a solution without the limitations of either approach. This approach was successfully demonstrated in a related project called the Energy Futures Forum where a partial equilibrium, national general equilibrium and global general equilibrium model were interfaced to achieve such an outcomes (see Energy Future Forum, (2006) and CSIRO and ABARE (2006)). Others studies have also interfaced partial and general equilibrium models. For example, The Climate Institute (2007) interface a partial equilibrium model of the electricity sector with a national general equilibrium model.

Whilst past research shows that the iterative modelling interface procedure works, it is a resource and time intensive process. When such processes are used it generally limits the range and number of scenarios that can be explored and lengthens the project timeline since more time is needed to complete modelling between each interaction with the scenario development group.

Given the need for information from the study to feed into strategic policy and investment decision making in a timely manner, this partial to general equilibrium model interface approach was ruled out. Apart from the timing issues another consideration was the preference for avoiding duplication: at the time of this study there are several other modelling groups working in government general equilibrium models and likely to complete their work at a similar time (Garnaut Review 2008; National Emissions Trading Taskforce, 2008).

So that the wider economy interactions are not overlooked in the partial equilibrium modelling we employ an alternative approach to the model interface method. Our approach is to find data which can provide an imperfect proxy for the state of the whole economy under each scenario and interface that data with a partial equilibrium model rather than the general equilibrium model. This approach can provide results which are broadly consistent with the results of a partial equilibrium-general equilibrium interface providing the data is available that is relevant to the scenarios being explored.

There have been several studies which outline the economy wide impacts of the scenario drivers relating to emission trading and high oil prices which are the main areas of concern in this study. For example, recent studies of the impact of emission trading on economic growth find that annual economic growth is reduced by around 0.1 percent from, for example, 2.4 to 2.3 percent growth depending on the base level of growth in the economy (Energy Futures Forum 2006; The Climate Institute 2007). This amounts to an 8 percent reduction in GDP by 2050 relative to a reference case without emission trading.

Note, these model outputs only include the cost of emission trading or mitigation activities on the economy. They do not include the benefits of mitigation from reduced future climate change impacts. Therefore it should not be assumed from these analyses that addressing climate change by reducing greenhouse gas emissions will necessarily harm the economy in net terms over time. Energy Futures Forum (2006) is one study that attempts to assess this broader question of net benefits of mitigation.

In relation to oil prices, Energy Futures Forum (2006) found that sustained oil prices of around US$100/bbl would reduce economic growth by around 3 percent in the year that price was reached relative to a reference case where oil prices in the same year had returned to their long term average of around US$35/bbl.

By applying this economy wide impact data from the literature to CSIRO's Energy Sector Model (ESM) we are able to limit but not completely address the issues associated with a partial equilibrium model. As such further examination of the wider economic impacts of the scenarios examined in this report is recommended for future research.

The discussion above refers to partial and general equilibrium models but note these may also be referred to in the literature as being bottom-up and top-down models respectively. Hourcade et al. (2006) provides a recent review of the application of bottom-up and top-down modelling in the context of energy policy scenarios. That terminology was avoided here because other disciplines outside economics also use such terms. That is, bottom-up and top-down models are generally used to describe the scope of a modelling framework but do not exclusively refer to economic models that calculate a price equilibrium.

ESM

ESM is an Australian energy sector model co-developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Australian Bureau of Agricultural and Resource Economics (ABARE) in 2006. Since that time CSIRO has significantly modified and expanded ESM As discussed ESM is a partial equilibrium (bottom-up) model of the electricity and transport sectors. The model has a robust economic decision making framework around the cost of alternative fuels and vehicles as well as detailed fuel and vehicle technical performance characterisation such as fuel efficiencies and emission factors by transport mode, vehicle type, engine type and age. It also has a detailed representation of the electricity generation sector. Competition for resources between the two sectors and relative costs of abatement are resolved simultaneously within the model.

Model equations and structure

ESM is solved as a linear program where the objective function is to maximise welfare which is the discounted sum of consumer and producer surplus over time. The sum of consumer and producer surplus are calculated as the integral of the demand functions minus the integral of the supply functions which are both disaggregated into many components across the electricity and transport markets. The objective function is maximised subject to constraints which control the physical limitations of fuel resources, the stock of electricity plant and vehicles, greenhouse gas emissions as prescribed by legislation, and various market and technology specific constraints such as the need to maintain a minimum number of peaking plants to meet rapid changes in the electricity load. See Graham and Williams (2003) for an example of the equations required to construct a similar partial equilibrium model.

The main components of ESM include:

- Coverage of all States and the Northern Territory (Australian Capital Territory is modelled as part of NSW);
- Trade in electricity between National Electricity Market States;
- Nine road transport modes: light, medium and heavy passenger cars; light, medium and heavy commercial vehicles; rigid trucks; articulated trucks and buses;
- Twelve road transport fuels: petrol; diesel; liquefied petroleum gas (LPG); natural gas (compressed (CNG) or liquefied(LNG)); petrol with 10 percent ethanol blend; diesel with 20

percent biodiesel blend; ethanol and biodiesel at high concentrations; gas to liquids diesel; coal to liquids diesel with upstream CO_2 capture; hydrogen (from renewables) and electricity;

- Rail, air and shipping sectors are governed by much less detailed fuel substitution possibilities;

- Four engine types: internal combustion; hybrid electric/internal combustion; hybrid plug-in electric/internal combustion and fully electric;

- Seventeen centralised generation (CG) electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with partial CO_2 capture and sequestration (CCS) (50 per cent capture rate); black coal with full CCS (85 per cent capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal with partial CCS (50 per cent capture rate); brown coal with full CCS (85 percent capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with full CCS (85 per cent capture rate); biomass; hydro; wind; solar thermal; hot fractured rocks (geothermal) and nuclear;

- Fourteen distributed generation (DG) electricity plant types: internal combustion diesel; internal combustion gas; gas turbine; gas micro turbine; gas combined heat and power (CHP); biomass CHP; gas micro turbine CHP; gas reciprocating engine CHP; solar photovoltaic; biomass; wind; biogas reciprocating engine; natural gas fuel cell and hydrogen fuel cell;

- All vehicles and centralised electricity generation plants are assigned a vintage based on when they were first purchased or installed in annual increments;

- Four electricity end use sectors: industrial; commercial and services; rural and residential

- Time is represented in annual frequency (2006, 2007, …, 2050).

Greater detail and some further discussion for why this technology aggregation was chosen for the model is provided in Appendices A and B.

All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, existing or new policies such as subsidies and taxes. The model aims to mirror real world investment decisions by simultaneously taking into account:

- The requirement to earn a reasonable return on investment over the life of a plant or vehicle

- That the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically

- That consumers react to price signals

- That the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy and transport services

- Energy and transport market policies and regulations.

The model evaluates uptake on the basis of cost competitiveness but at the same time takes into account the key constraints with regard to the operation of energy and transport markets, current excise and mandated fuel mix legislation, GHG emission limits, existing plant and vehicle stock in each State, and lead times in the availability of new vehicles or plant. It does not take into account issues such as community acceptance of technologies but these can be controlled by imposing various scenario assumptions which constrain the solution to user provided limits.

Model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, ESM determines the time paths of the endogenous (output) variables. Key output variables include:

- Fuel, engine and electricity generation technology uptake
- Fuel consumption
- Cost of transport services (for example, cents per kilometre)
- Price of fuels
- GHG and criteria air pollutant emissions
- Wholesale and retail electricity prices
- CO_2e permit prices
- Demand for transport and electricity services.

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step for fuels, electricity and transport services, and over time for assets such as vehicles and plant capacities. With respect to asset markets, the assumption is used that market participants know future outcomes of their joint actions over the entire time horizon of the model.

Limitations of ESM

The limitations of partial equilibrium models in their representation of transport infrastructure and economy wide impacts (and possible remedies for these) has already been discussed above and so are not repeated here. The modelling conducted for this report suffers from two additional major limitations which are discussed.

The first is that it includes many assumptions for parameters that are in reality uncertain and in some cases evolving rapidly. Parameters of most concern include for example possible breakthroughs in so called “second generation” biofuel production technologies and the unknown quality and cost of future offerings of fully and partially electrified vehicles. These limitations are only partially addressed by sensitivity cases.

A second major limitation is that ESM only takes account of cost as the major determining factor in technology and fuel uptake. Therefore, it cannot capture the behaviour of so-called “fast adopters” who take up new technology before it has reached a competitive price point. For example, most consumers of hybrid electric vehicles today could be considered “fast adopters”. Their purchase cannot be justified on economic grounds since the additional cost of such vehicles is not offset by fuel savings in any reasonable period of time (relative to the cost of borrowing). Nevertheless, hybrid electric vehicles are purchased and such purchasers may be motivated by a variety of factors including a strong interest in new technology, the desire to reduce emissions or status. As a result of this limitation, ESM’s projections of the initial technology uptake for new technologies could be considered conservative.

However, another factor which ESM overlooks is community acceptance and this limitation might lead ESM to overestimate the rate of uptake of some fuels and technologies. For example, greater use of gaseous fuels such as Liquefied Petroleum Gas (LPG) and the introduction of electricity as a transport fuel might be resisted by the Australian community which has predominantly used liquid fuels for transport over the past century. By design, ESM only considers whether the choice is economically viable.

As a result of these limitations, the technology and fuel uptake projections need to be interpreted with caution. In reality, consumers will consider a variety factors in fuel and vehicle purchasing decisions. However, it is the view of the authors that the projections presented in this report, are nonetheless instructive in that they indicate the point at which the various abatement options should become widely attractive to all consumers. The projections indicate that an increasing diversity of options are likely to become attractive compared to the present fuel and technology mix.

SCENARIOS

In developing scenarios, the Future Fuels Forum were encouraged to explore a diverse range of potential drivers for change in the future that might impact upon the future of transport fuels in Australia. The resulting scenarios do not represent a consensus position about the future, nor do they necessarily represent desirable futures. They are merely plausible futures that are representative of some of the potential range of futures facing the transport and fuel industry. Each Forum participant will hold a variety of views about the plausibility of each scenario. No attempt is made to assign a probability to the events in the scenarios.

Forum discussions resulted in a wide range of ideas. The Future Fuels Forum then worked with the modelling team to arrive at a set of scenarios that were able to be modelled within the limitations of ESM and that adequately represented the breadth of issues discussed.

Ideas were initially grouped into themes. Five themes that emerged most strongly from the discussions were:

- The introduction of emission trading in Australia
- The potential for more constrained oil supply and/or higher oil prices
- Social and cultural preferences with regard to share of different transport modes (rail, air road and sea), (road) vehicle size and the frequency and length of transport use
- The availability, cost and effectiveness of alternative fuel and engine technologies
- The potential for the introduction of additional government polices to enhance emission reduction in transport or to achieve other policy objectives

The next step was to determine whether all themes warranted individual scenario analysis or whether some factors should be combined.

In considering the issue of cultural and social preferences, it was felt that due to the likely introduction of emission trading in Australia coupled with higher oil prices that social and cultural preferences relating to transport were likely to be common to all scenarios and would support lower growth in transport demand.

Similarly, in response to the same factors, it was felt that in all scenarios Australia is likely to see an acceleration of the availability and take-up of alternative fuel and engine technologies.

Given these observations it was decided that a default social and cultural preference setting which determines transport demand would be applied across all of the scenarios. These assumptions are detailed in Appendix A. However, we explore a sensitivity case where contrary to the default assumptions social and cultural preferences remain unchanged from the present day.

It was also decided that CSIRO would provide a default technology outlook and allow the model to determine what technology would be selected based on relative cost. This means providing the model with all of the technology cost and performance parameters over time. For these assumptions see Appendix A. In addition, we explore several sensitivity cases around particular technologies of interest. The technologies selected for further sensitivity case analysis were algae-based biodiesel, hydrogen, nuclear power and CO_2 capture and storage.

In order to learn more about the impact of additional transport policies that might come into place we needed to model emission trading in isolation and emission trading plus additional transport sector policies. As such a set of additional transport polices are modelled as sensitivity cases. In total, four additional transport policies are modelled and were selected on the basis that they: employed a variety of policy levers, were relatively easy to model and explored different types of incentives effects. They are: accelerated vehicle scrapping; higher fuel excise; low emission vehicle subsidies; and mandatory vehicle fuel efficiency improvements.

Core scenarios

With the themes of social preferences, technology and additional government polices provided as default assumptions or explored in sensitivity cases, only two drivers - emissions trading and the degree to which international oil supply is constrained – are varied to make up the "core scenario" set.

National emission trading scenarios

For emission trading we explore two scenarios. The first is the present government's target of limiting emissions to 60 percent below 2000 levels by 2050. When a constant rate of decline is applied from 2010, this implies an emission limit of 20 per cent above 1990 levels by 2020. The second emission reduction target explored is the more ambitious target of reaching a limit of 95 percent below 2000 levels by 2050. This equates to a target of 30 percent below 1990 levels by 2020.

The deeper emission reduction target was chosen on the basis that while the present government's target is challenging, it still entails significant risk to the environment particularly if phased in at a constant rate as modelled here. The scenario of a near-zero emission target of 95 percent below 2000 levels by 2050, if adopted by developed countries worldwide and with some contribution from developing countries on a relative emission per capita basis, would significantly reduce the risk of irreversible climatic impacts associated with exceeding average global warming of above 2 degrees Celsius. Avoiding this threshold level entails deep emission cuts in the period to 2020 of below 1990 levels in developed countries. For a discussion of potential environmental impacts associated with exceeding 2 degrees Celsius warming see chapter six of Energy Futures Forum (2006).

Constrained oil supply and higher oil price scenarios

The Future Fuels Forum wished to acknowledge the wide range of uncertainty in regard to the possible outcomes in the international oil market. As such the modelling explores three different scenarios of how conditions in the international oil market might evolve.

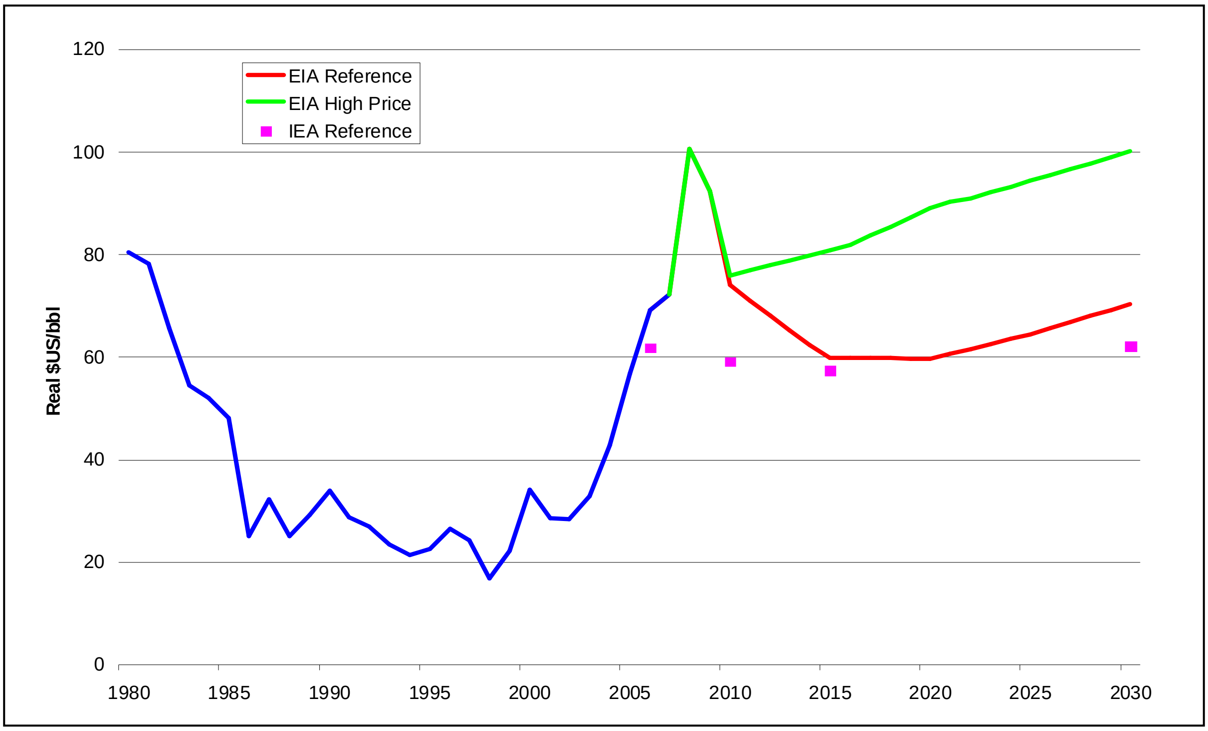
For two of the scenarios the modelling draws on international projections from EIA (2007, 2008a and 2008b). EIA (2008a) provides a short term oil price outlook, while EIA (2007) and EIA (2008b) provide projections to 2030.

The first scenario that is explored in the modelling assumes that after peaking at US$100/bbl in 2008, oil prices of around US$60 to US$70 will be maintained for the next several decades. This represents a significant break from the average in the previous decade of around US$28/bbl. All of these prices are annual averages in real terms (base year 2006). We do not attempt to model the daily market volatility. For example, in 2008 prices have exceeded $130/bbl in various trading days, however our assumption, based on EIA (2008a), is for an average annual price of $100/bbl.

The second scenario explored is that the oil price will recover slightly from their current high levels but will then steadily increase over the next few decades. Scenarios which assume only moderate increases in the international oil price imply that oil production will expand since demand is unlikely to reduce of its own accord (except perhaps if global emission trading were to substantially constrain transport). These first two scenarios therefore rely on the existence and discovery of new oil resources and new technology and processes for accessing a greater portion of known oil resources at lower cost.

To construct our steady and moderately increasing oil price paths we have adopted the reference and high oil price scenarios contained in EIA (2007 and 2008b). These prices are shown in Figure 1 together with the IEA reference case (IEA, 2007).

Figure 1: EIA reference and high oil price cases and the IEA reference case



The third scenario assumes a near term peak in world oil production. This report does not review the peak oil literature. However, for the purposes of modelling, the scenario is taken to mean that from a certain point in time, due to oil resource constraints it will be impossible to supply increasing quantities of oil. In this scenario we do not set a price for oil but rather simply supply the model with the information that oil based fuel products are increasingly less available each year in time starting from 2010. This date was arbitrarily chosen. There are a wide variety of views on when oil production peak will have peaked. The model then determines the market equilibrium price that would result from these circumstances. The expectation, however, is that this would lead to a significant price spike that would only begin to end when substitutes to oil based fuel products become readily available.

How the market will respond to a peak oil event will depend very much on how fast alternative fuels and vehicles become available in that event and how quickly the availability of oil based fuel declines. As a result modelling of this scenario will include six combinations of events being two oil decline rates (slow and fast) and three alternative fuel and vehicle availability rates (slow, moderate and fast). The specific assumptions around these rates are discussed in the modelling results section below. The two extremes – slow oil products decline with fast infrastructure response and fast oil products decline with slow infrastructure response – are treated as core scenarios for reporting purposes and the remaining four combinations are discussed as sensitivity cases.

Summary of scenarios

Table 1 summarises the core scenario set. It includes four oil market conditions: two specifying oil prices only and two specifying oil availability and the response of the alternative fuel and vehicle industry. For each of these oil market conditions two national emission trading targets are explored.

Table 1: Core scenario set

International oil market conditions	National emission trading targets*
Steady oil prices: EIA reference case oil price (Figure 1) extrapolated to US$88/bbl by 2050	- 20% above 1990 levels in 2020, 60% below 2000 levels by 2050 - 30% below 1990 levels by 2020, 95% below 2000 levels by 2050
Moderately increasing oil prices: EIA high oil price (Figure 1) extrapolated to $US133/bbl by 2050	- 20% above 1990 levels in 2020, 60% below 2000 levels by 2050 - 30% below 1990 levels by 2020, 95% below 2000 levels by 2050
Slow decline in oil supply with fast rate of increase in availability of alternative fuels and vehicles (Resulting prices calculated by the model)	- 20% above 1990 levels in 2020, 60% below 2000levels by 2050 - 30% below 1990 levels by 2020, 95% below 2000 levels by 2050
Fast decline in oil supply with slow rate of increase in availability of alternative fuels andvehicles (Resulting prices calculated by the model)	- 20% above 1990 levels in 2020, 60% below 2000 levels by 2050 - 30% below 1990 levels by 2020, 95% below 2000 levels by 2050

*2000 levels are used to describe 2050 targets as this is the comparison point chosen by the Federal Government. 1990 levels are used to describe 2020 targets as this is the comparison point applied for Kyoto Protocol greenhouse gas emissions accounting which extends to 2012 where Australia's target is 8 percent above 1990 levels. In practice there is little difference between 1990 and 2000 levels as a reference point.

Table 2 shows the sensitivity cases that are explored. These sensitivity cases are not applied to all of the core scenarios. Themes 1 to 3 are applied to the core scenarios where the oil price is set to the two EIA (2007 and 2008) price paths and oil supply remains unconstrained. They are not applied to the scenarios where oil supply is assumed to decline. Theme 2 sensitivity cases, Technology, are only applied to the moderately rising EIA high oil price scenario to save computational and reporting effort.

The constrained oil supply scenarios are very challenging and the impacts occur almost immediately in the modelling projection period. For this reason, most of the sensitivity cases being explored are not relevant, having their impact after the period of constrained oil supply. The sensitivity cases that are explored in the constrained oil supply scenarios are the four additional cases where the rate of decline in oil product supplies and rate of increase in availability of alternative fuel and vehicles is explored.

Table 2: Sensitivity cases

Theme	**Case explored**
1. Social and cultural preferences for transport	- Social preferences remain unchanged from present. As a result demand for private passenger road transport is higher and demand for mass transport lower
2. Technology	- Algae-based biofuel become available at low cost
	- Hydrogen road vehicles are available at competitive cost
	- Nuclear power as an option[1]
	- CO_2 capture and storage is not available and electricity end-use efficiency is higher
3. Additional government polices	- Accelerated scrapping of older road vehicles
	- Higher fuel excise
	- Subsidies for low emission road vehicles
	- Mandatory fuel efficiency improvements for road vehicles
4. Rate of decline in oil product supplies and	- Slow decline, slow infrastructure response
rate of increase in availability of alternative	- Slow decline, moderate infrastructure response
fuel and vehicles	- Fast decline, moderate infrastructure response
	- Fast decline, fast infrastructure response

Additional notes on modelling national emissions trading

A national CO_2e emission trading scheme is scheduled to be introduced in Australia by the end of 2010. Researchers in government and independent of government have been given the task of designing the scheme (e.g. Garnaut Review 2007). As that design is not yet complete the modelling here implements a relatively "pure" version of emission trading that largely ignores features such as banking of emission permits, borrowing permits, price caps, price floors and issuing of permits to

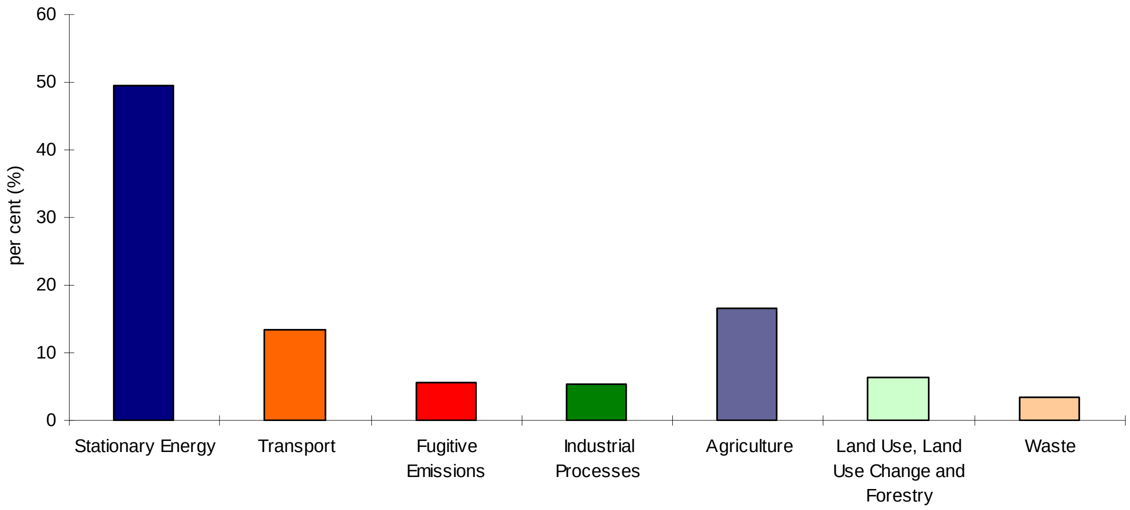
[1] The inclusion of this sensitivity case does not represent an endorsement of nuclear power as an option on the part of any or all Future Fuels Forum participants.

existing emitters. However, there are some additional assumptions that must be included when modelling a national scheme in an energy sector (partial equilibrium) model.

Modelling a national emission trading scheme in a partial equilibrium model

A national emission trading scheme does not specify an abatement target for each major greenhouse gas emitting sector – just one for all the sectors covered. As a result, the CO_2e permit price is set by the cost of the last tonne of abatement in the sector where it was lowest cost to achieve that abatement. At any point in time, a greenhouse gas emitting sector may be a price maker or a price taker. Whether it is a price maker or price taker will depend on the relative cost of abatement in that sector and its relative share of total national emissions (for all sectors included in the scheme).

Figure 2: Sectoral shares of Australia's greenhouse gas emissions



Source: AGO (2007)

Figure 2 shows the share of emissions for each of the major greenhouse gas emitting sectors. Assuming all sectors are included in a national emissions trading scheme, electricity and transport would account for around 49 percent of emissions (electricity is 70 percent of stationary emissions). If agriculture were excluded as was suggested in Prime Ministerial Task Group on Emissions Trading (2007) then this share would increase to 58 percent.

On the basis of the large share of the electricity and transport sector in total national emissions it would be reasonable to expect that this sector will be a price maker for significant lengths of time during the implementation of the scheme. However, this may not always be the case. Furthermore, if Australia's national emission trading scheme is linked with other international emission trading schemes it is possible that Australians could purchase emission permits in international markets, avoiding the need to directly incur all emission abatement costs in Australia. They could alternatively purchase emission credits which is an equivalent instrument because it offsets emissions for which an emitter does not have a permit. This approach is perfectly valid on environmental grounds since the effect of CO_2e permits are global, so long as there is agreement between participating countries on each country's target, the validity of permits and credits issued and coordination of greenhouse gas reporting and measurement methodologies.

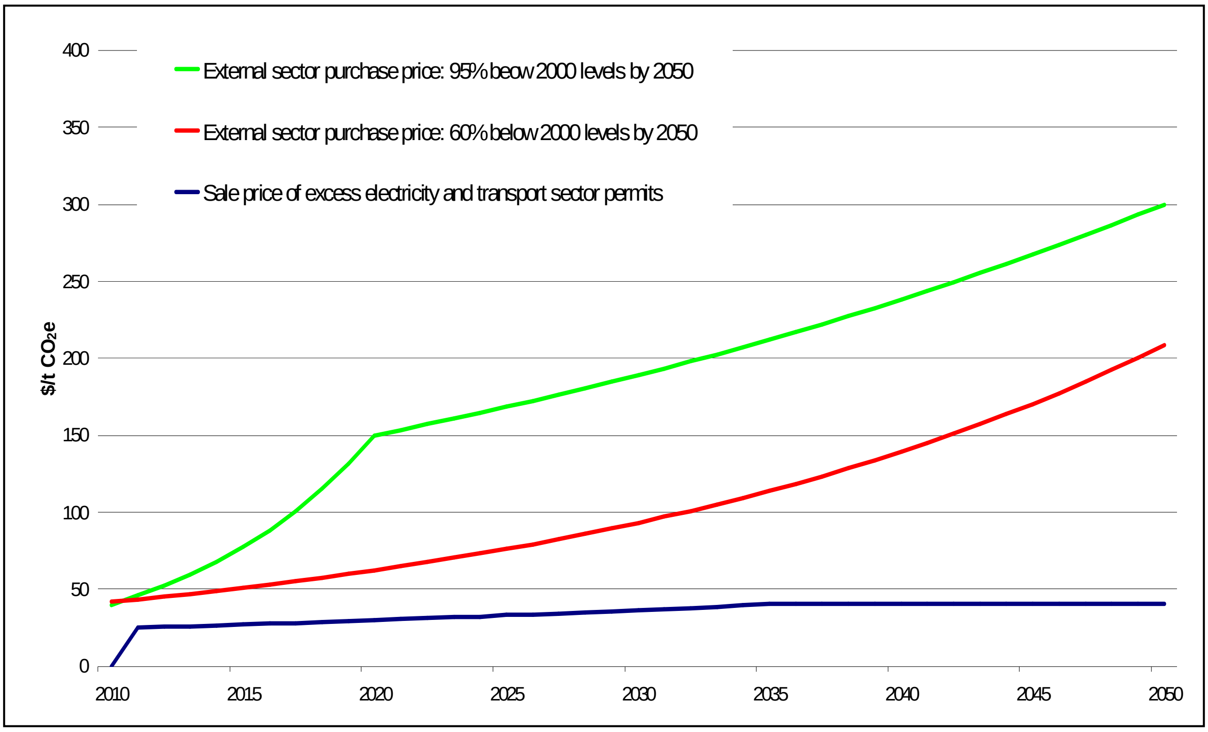
With the potential for lower cost abatement in other Australian or international emission sectors it would not be appropriate to simply apply a proportional sectoral emission target to cover the sectors included in ESM and assume that is adequate for determining the price of CO_2e permits in Australia. The approach that is applied is to provide an upper bound on the CO_2e permit price in ESM by making available an unlimited number of permits at a pre-defined price. These permits would be purchased whenever the cost of abatement in the electricity and transport sectors is above the upper bound.

For the 60 percent below 2000 level by 2050 emission target the assumed upper bound on the cost of abatement from other sectors begins at around A\$40/tCO_2e in 2010 and increases at a constant percentage rate to A\$200/tCO_2e in 2050, consistent with mid range estimates of carbon prices reviewed by the IPCC (Fisher et al. 2007). For our 60 percent below 2000 level by 2050 emission target, a higher CO_2e permit upper bound price path is assumed to take account of the steeper rate of reduction to 2020 and the possible increased competition for abatement certificates in domestic and international markets under such a scenario.

Where the cost of abatement in the electricity and transport sectors is below the cost of abatement in other sectors, rather then buying permits, the sector will be selling permits. If they cannot sell emission permits the CO_2e permit price could potentially fall dramatically on occasions where investment in low emission technology proceeds faster than is required by the proportional target (see for example, Graham et al. 2008). To prevent the potentially unrealistic scenario that CO_2e permit prices would fall to near zero we impose a CO_2e permit sale price of \$25/tCO_2 increasing to \$40/tCO_2e throughout the projection period. This effectively sets the lower bound for CO_2e permit prices.

Figure 3 plots the prices for emission permits purchased from or sold to sectors outside the electricity and transport sector.

Figure 3: Price of CO_2e abatement in sectors outside electricity and transport and minimum sale price for excess permits



Expected impact of a CO_2e permit price

ESM models the whole cost of transport which includes not just fuel costs, but capital, registration, insurance, maintenance and any relevant taxes. It is important to model all of these factors when considering greenhouse gas reduction in transport, because each factor contributes to the overall cost of abatement. For a medium passenger road vehicle this whole cost of transport is around 60c/km. Of that, fuel contributes around 10c/km. The largest item is the cost of the vehicle.

A CO_2e permit price of \$50/tCO_2e increases the retail petrol price by about 12c/L. This adds an additional 1c/km or 1.8 percent to the overall cost of transport. It is fairly obvious from this example that the Australian transport sector is not likely to be very sensitive to CO_2e permit prices. That is, it will take a fairly high CO_2e permit price in order to create a price differential for consumers that convinces them to shift to another fuel or type of vehicle or find another mode of transport.

In contrast one can expect that electricity sector emissions could be substantially reduced by deployment of new technology for an abatement cost of around A\$50/tCO_2e and that would tend to encourage a greater proportion of abatement in the electricity sector compared to the transport sector for a given CO_2e permit price level (Reedman and Graham, forthcoming). It would also tend to encourage the electrification of the transport sector if such technology is not cost prohibitive.

Electricity generation in Australia currently has an average emission factor of approximately 1 tCO_2e/MWh. Wholesale electricity prices in the National Electricity Market (NEM) in the absence of emissions trading are around A\$40/MWh. Accordingly, the introduction of a CO_2e permit price will initially increase the wholesale cost of electricity generation by A\$1/MWh for each A\$1 increase in the CO_2e permit price. Low emission electricity generation technologies are expected to be available at costs of between A\$50-100/MWh (see Appendix B).

SCENARIO MODELLING RESULTS

Core scenarios

Steady oil price scenario: EIA reference case oil price

The EIA reference oil price scenario represents a scenario where the oil price peaks at around US$100/bbl in 2008 and quickly falls back to US$60/bbl by 2015 (all prices in real terms). After that is rises slowly to around US$70/bbl by 2030. By extrapolating this trend beyond the EIA forecast period of 2030 the price of oil is US$88/bbl in 2050 in this scenario.

While these price movements represent little more than a continuation of present oil prices with some minor volatility, they can still be expected to result in significant technological change. The key driver of technological change is the maintenance of oil prices at above US$60/bbl for sustained periods which enables investment confidence in many technologies that were too costly at average oil price of US$28/bbl last decade. This sustained higher level of oil prices is also responsible for slow growth in travel demand which is evident in the modelling results presented below (see also the sensitivity case where social and cultural preferences in relation to transport use are held constant).

Emission target is 60 percent below 2000 levels by 2050

For the scenario where the emission target is 60 percent below 2000 levels by 2050 (2000-60), Figure 4 shows the kilometres travelled by mode and road vehicle type. This model output largely reflects the default demand growth assumptions for each of the modes reflecting a slowing in the rate of growth in private passenger road transport, greater uptake of lighter vehicle classes and stronger growth in mass transport such as buses and non-road modes.

Figure 4: Kilometres travelled by mode and road vehicle type: EIA reference oil price and 2000-60 emission target

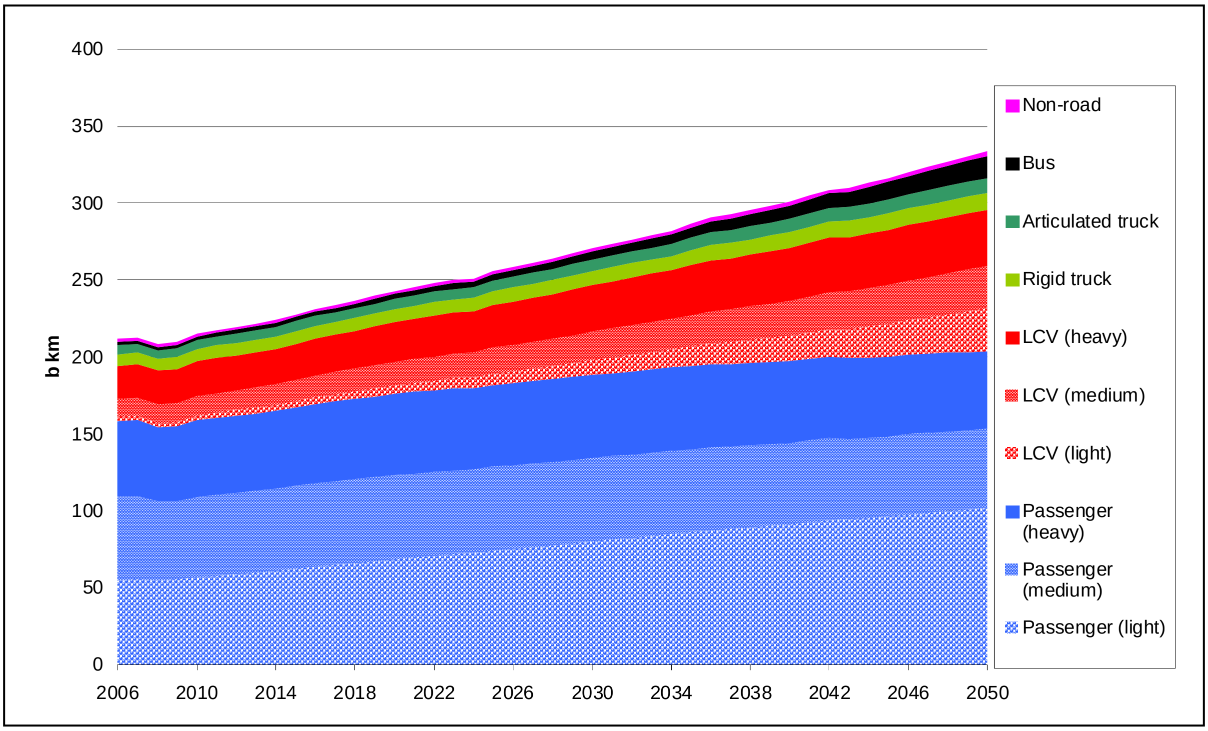
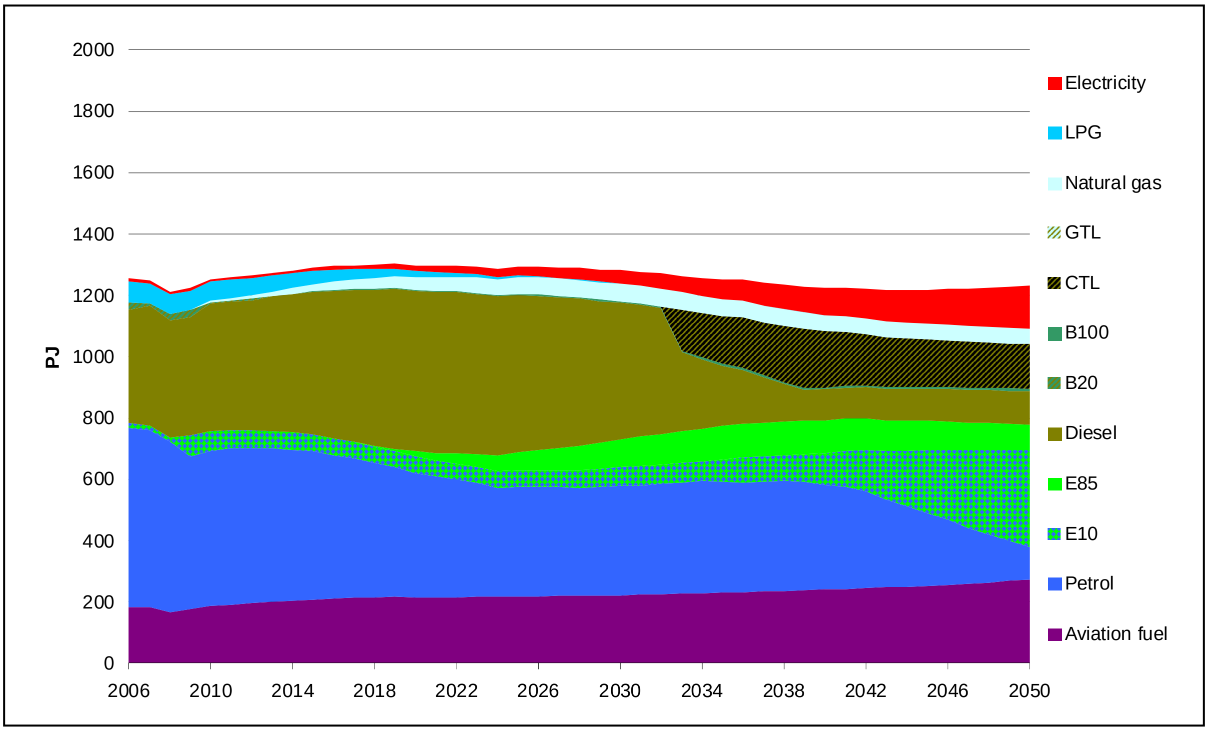


Figure 5: Transport sector fuel consumption: EIA reference oil price and 2000-60 emission target[2]



Non-road transport modes do not travel significant kilometres relative to total road modes. However, they consume significant amounts of fuel as can be seen in Figure 5 where domestic aviation accounts for 17 percent of total transport fuel consumption and rail and sea transport around 25 percent of all diesel fuel consumption.

Looking to the future, the modelling results project that a much more diverse fuel mix will evolve in response to oil prices being sustained above US$60/bbl and the introduction of emission trading. The initial response to these market forces is projected to initially result in greater uptake of diesel fuel, natural gas (mainly by the articulated truck fleet in the form of LNG) and ethanol (initially as E10 and later as E85).

E10 and E85 fuel consumption receives a significant boost in 2020 as this is the period in which it is assumed lignocellulosic processes for producing ethanol become cost competitive. Biodiesel consumption remains steady throughout the projection period reflecting the limited volumes available at a competitive price. Algae based biodiesel is assumed to be technically feasible by 2015 but not cost competitive. To explore the scenario where algae based biodiesel is cost competitive see the sensitivity case below.

Electricity steadily expands its role as a transport fuel throughout the projection period increasing from the 8PJ currently which is consumed exclusively by rail transport to 149PJ or 41TWh where the road transport mode is the dominant electricity user. Note, electricity consumption only includes that drawn from the grid, not than generated in the vehicle via any other means. The uptake of electric and hybrid

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[2] Note, throughout the report, to simplify the diagram shipping fuel ("bunker oil") consumption is included in the diesel category since it would appear that the industry will shift toward diesel over the longer term (International Marine Organisation, 2008). Rail diesel and electricity consumption is included in those respective categories. Use of biofuels in the shipping, rail and aviation sectors appears in the relevant biofuel categories.

electric vehicles appears to be the cause of the reduction in LPG usage. In this context, electricity can be seen as a potential competitor to LPG as a way of reducing fuel costs.

The emergence of the partial electrification of the road transport sector is shown in greater detail in Figure 6. It shows that by 2050 plug-in hybrid electric and full electric vehicles will account for around a third of the road vehicle fleet. Mild hybrids which generate their electricity on board rather than drawing on the electricity grid are projected to account for another 50 percent of the fleet leaving internal combustion vehicles occupying only one sixth of vehicles.

As discussed in the section on model limitations, ESM is not able to project the current known annual sales of hybrid electric vehicles because such sales represent choices by “fast adopters” who partially disregard the relative cost of those vehicles. Even if capturing this market were a capability of ESM, the existing fleet of hybrids will not be visible on Figure 6 until they reach around 50,000 vehicles.

Another feature of the modelling is that fully electric vehicles tend to lead uptake of hybrid electric vehicles. This follows from the assumption that a purely electric vehicle will have fewer additional component costs and is only available to the light vehicle market and therefore not necessarily competing with hybrids.

The projected increasing electrification of the transport sector must of course be supported by increasing electricity production. This is automatically accounted for in the modelling and Figure 7 shows the projected level of electricity generation by technology category. It can be seen from these modelling results that the emission target has completely transformed the electricity sector from its present state.

The model projects that the next decade will see the uptake of wind and natural gas combined cycle plants. This is not surprising since they are the two current lowest cost low emission plant. However, once CO_2 capture and storage (CCS) is available in 2020, this technology begins to be deployed. CCS is applied to brown and black coal and any new gas plant is also fitted with the technology. At this rate of emission reduction, even gas is too emission intensive without CCS.

As the required emission intensity falls further toward the middle of the projection period, the steady expansion of renewables includes hot fractured rocks, biomass, solar thermal and solar photovoltaic, the latter is in the form of distributed generation which is embedded on site with the end-user (Figure 8).

Distributed generation output contributes almost 20 percent of total electricity generation by 2050. It initially consists of small diesel, biogas, biomass and natural gas cogeneration plants. However, as the required emission intensity of electricity declines, new growth in distributed energy is increasingly forced to switch to zero emission solar photovoltaic and micro wind plant from around 2020.

Figure 6: Share of different engine types in road kilometres travelled: EIA reference oil price and 2000-60 emission target

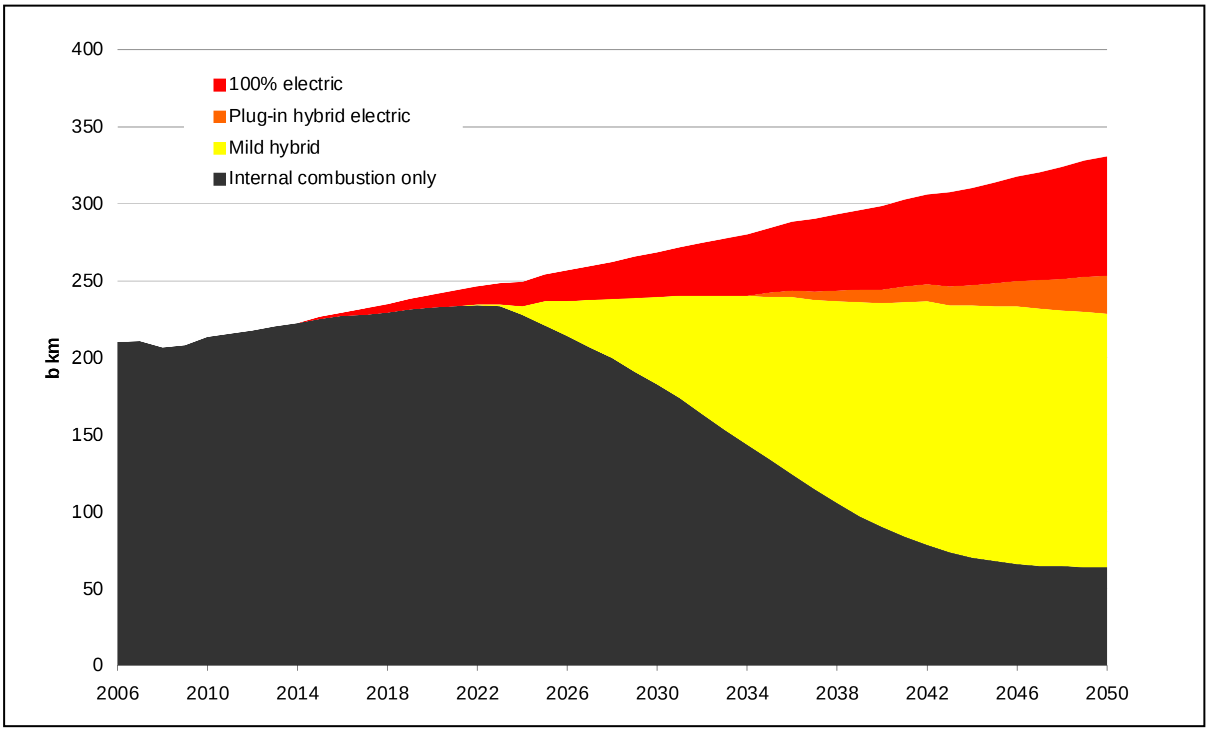


Figure 7: Electricity generation by technology: EIA reference oil price and 2000-60 emission target

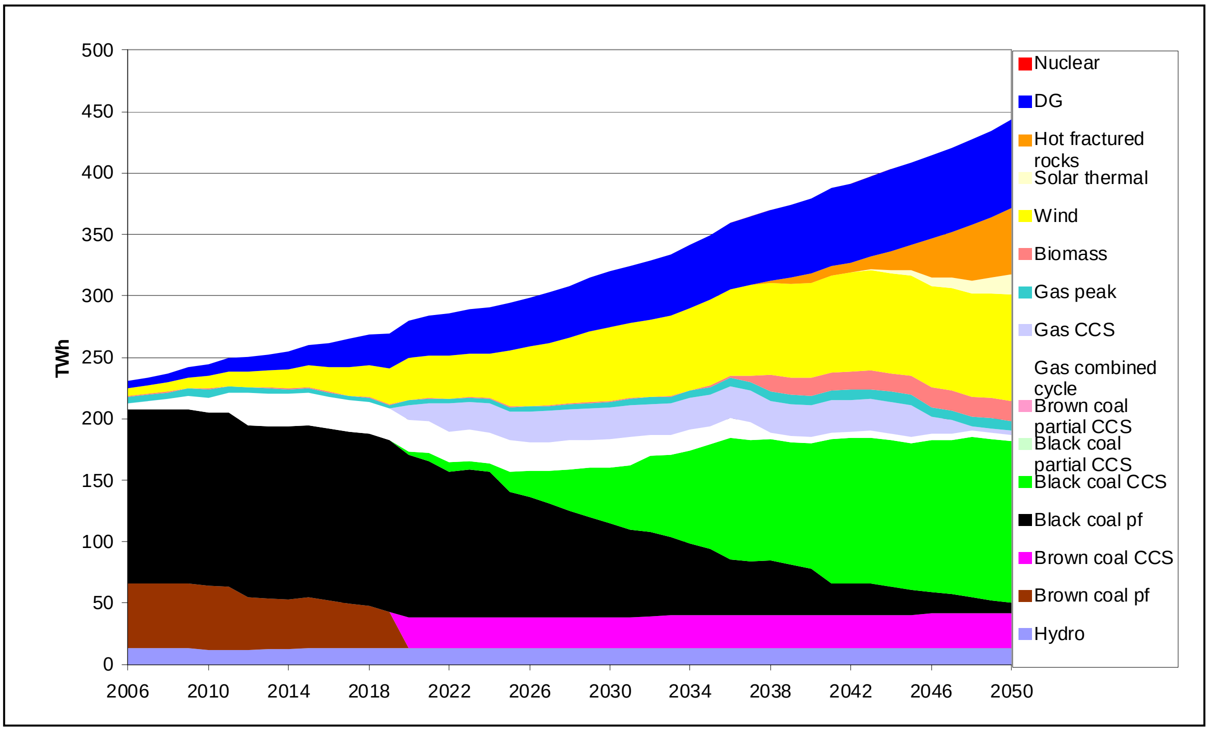


Figure 8: Distributed generation by technology: EIA reference oil price and 2000-60 emission target

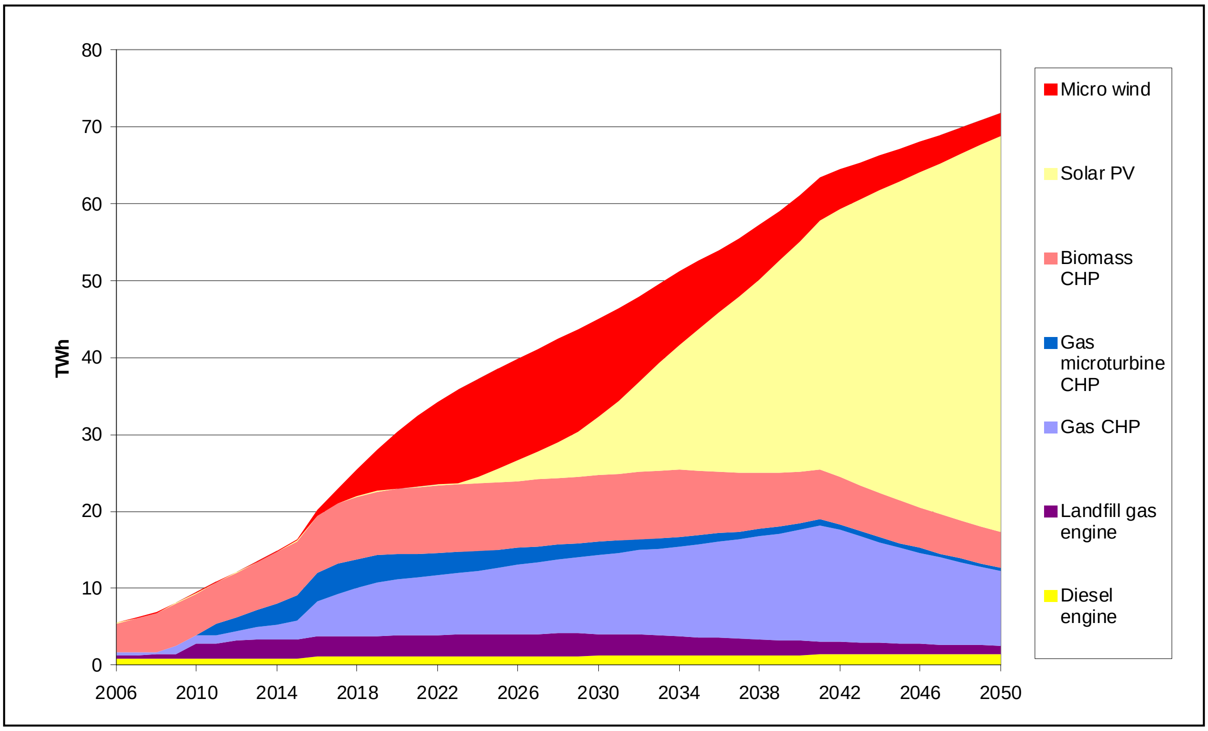


Figure 9 and Figure 10 show the detail of how the emission trading scheme has shaped and been shaped by the electricity and transport sectors. From Figure 9 it can be seen that, apart from the first few years of the scheme, up until 2025 the electricity and transport sectors cannot meet their proportional emission abatement target at below the cost of abatement in other sectors (which is shown in Figure 3). As a result they purchase CO_2e permits from outside of the electricity and transport sectors and the CO_2e permit price path in Figure 10 reflects this increasing from $40/t$CO_2e$ to almost $80/t$CO_2e$. From 2025 the cost of abatement in electricity and transport falls below the cost of abatement in other sectors and so the CO_2e permit price falls. This reflects the wider availability and scaling up of low emission fuels and technologies in both sectors after 2020.

From around 2035, there are three separate occasions where abatement in the electricity and transport sectors falls below the proportional target. These events are driven by the scheduled retirement of large blocks of existing coal fired electricity generation built in the 1980s which temporarily lead to rapid emission reductions. When this occurs the CO_2e permit price falls to $40/t$CO_2e$. However, the general trend through this period is a CO_2e permit price of $60/t$CO_2e$.

In comparing the electricity and transport sectors the result clearly shows that the electricity sector contributes more than its proportional share in meeting the target for the two sectors. This matches our expectations that the transport sector is less responsive than the electricity sector to CO_2e permit prices since fuels are a smaller component of the services consumed in transport. Some of the sensitivity cases discussed below explore whether transport can contribute a greater share of electricity and transport sector abatement.

Figure 9: Electricity and transport sector greenhouse gas emissions: EIA reference oil price and 2000-60 emission target

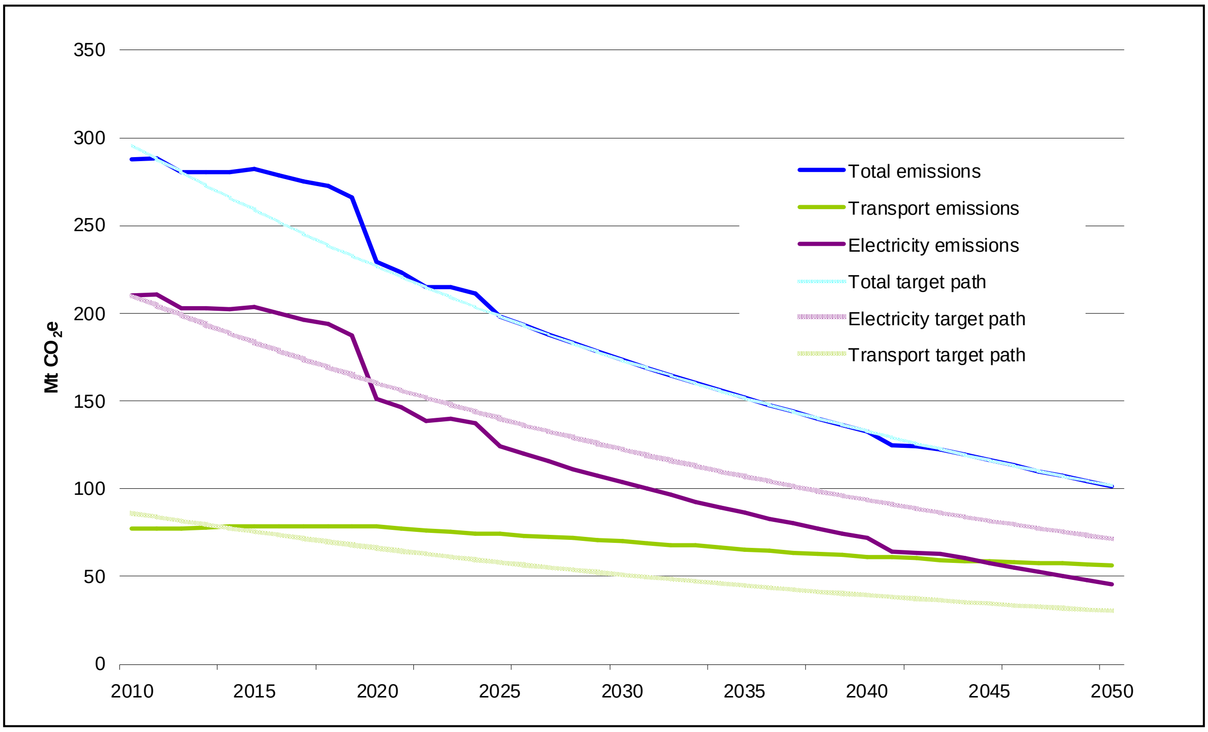
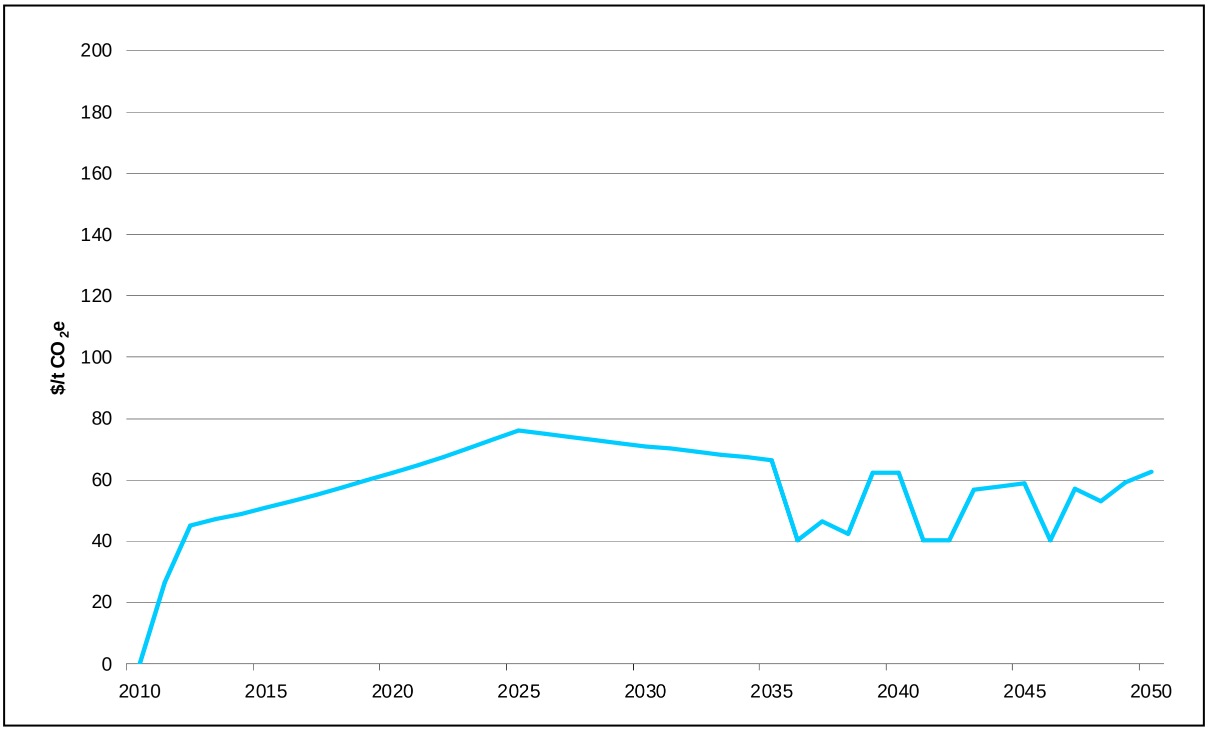


Figure 10: CO2e permit price: EIA reference oil price and 2000-60 emission target



Emission target is 95 percent below 2000 levels by 2050

We now discuss the case where the emission target is decreased to 95 percent below 2000 levels by 2050 (2000-95). An equivalent diagram for mode and vehicle type kilometres travelled is not shown as the reduction in travel activity relative to the previous scenario is only minor. However there are several features of the transport sector in this scenario that have changed.

Relative to the 2000-60 scenario, fuel consumption in the 2000-95 scenario is significantly lower by 2050 driven primarily by greater electrification of the road transport fleet via greater uptake of plug-in hybrid electric vehicles (Figure 11). In this scenario, by 2050, plug-in hybrid electric vehicles are as common as any other road vehicle engine configuration (Figure 12). A second feature of the fuel mix is that coal to liquids diesel fuel (with upstream CO_2 capture and storage) has almost disappeared from the fuel mix relative to 2000-60 where it played a significant role. This indicates that the higher emission abatement target is a threat to the viability of coal to liquids diesel even with CCS to capture upstream emissions. This may be a function of reduced demand for liquid fuels overall as much as the effects of the higher CO_2e permit price.

The differences in the electricity generation mix in 2000-95 relative to 2000-60 are more radical than those in the transport sector. First the increased level of electricity generation by 2050 must be noted. This is being caused by the increasing electrification of transport.

The other major feature is the rapidity with which the electricity sector is driven towards lowering its emission intensity. This involves early retirement of all existing coal fired plant by around 2025 (2015 for brown coal), reduced demand in the period between 2015 and 2020, rapid deployment of hot fractured rocks and gas with CCS when they becomes available in 2015 and 2020 respectively. It is interesting to note that no coal plant with CCS proceeds in this scenario. This is because it is assumed only 85 percent of emissions can be captured cost effectively. In this scenario which is aiming towards near zero emissions, those residual emissions are too much of a liability for the technology to proceed. The same is true for gas with CCS, however its residual emissions are of a lower intensity due to the lower carbon content of gas. This allows the technology to proceed for several decades but even gas with CCS is shut down from 2045.

The modelling shows that renewables are the primary technology required to meet the 2000-95 emission target. Compared to the 2000-60 emission target, renewable electricity generation constitutes almost the entire electricity supply system by 2050 in the 2000-95 scenario.

In terms of distributed generation, relative to the 2000-60 emission target scenario the modelling projects a much smaller role for gas based distributed generation. This finding is again driven by the need to rapidly reduce emissions. Under this scenario gas fired distributed generation is too emission intensive.

Figure 11: Transport sector fuel consumption: EIA reference oil price and 2000-95 emission target

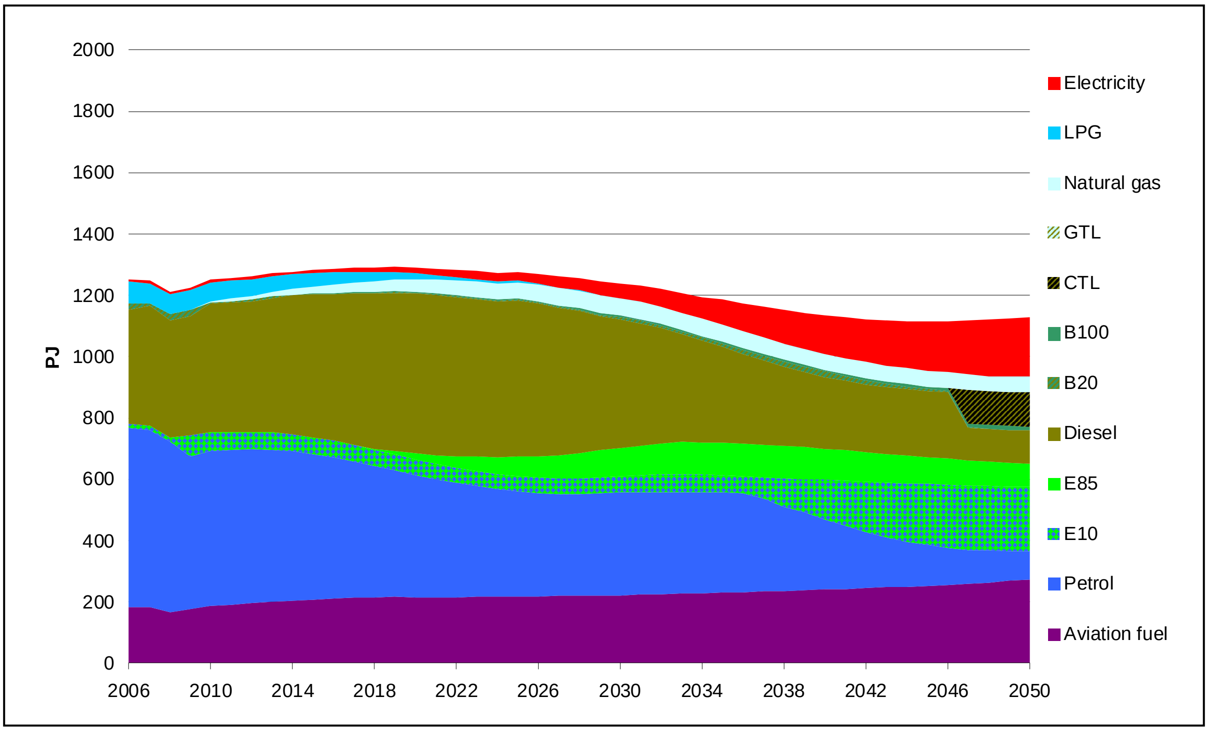


Figure 12: Share of different engine types in road kilometres travelled: EIA reference oil price and 2000-95 emission target

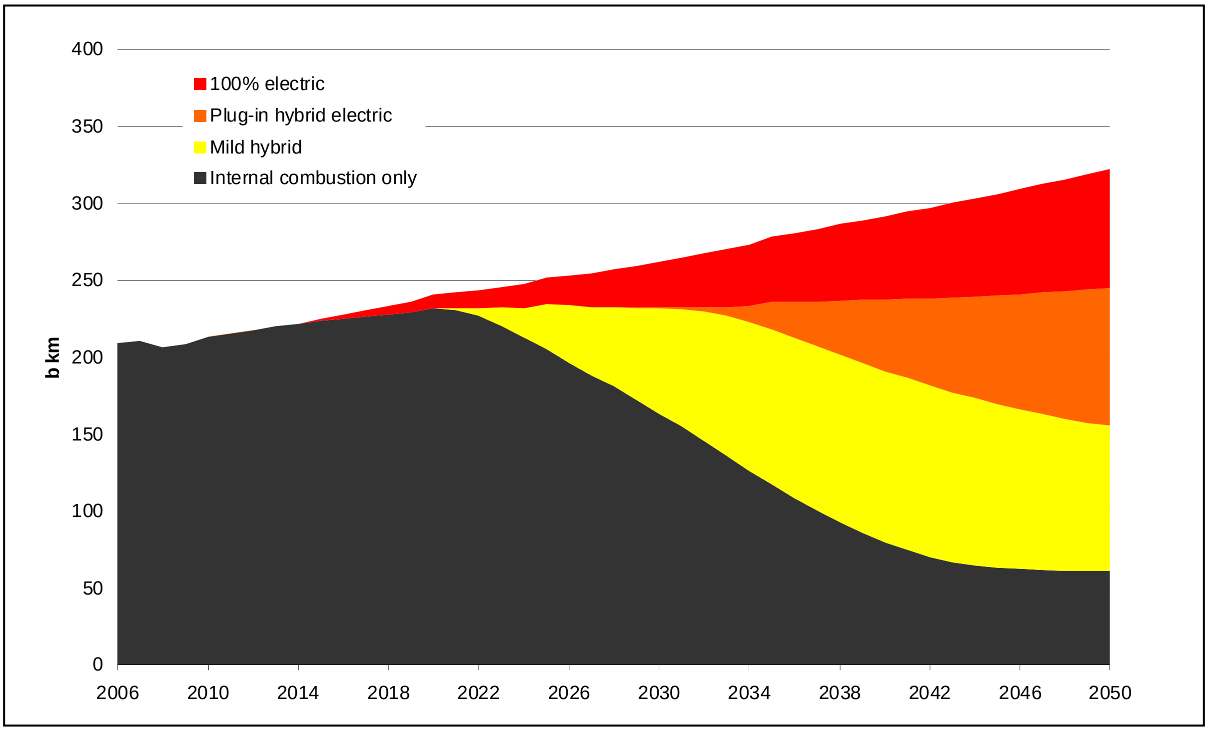


Figure 13: Electricity generation by technology: EIA reference oil price and 2000-95 emission target

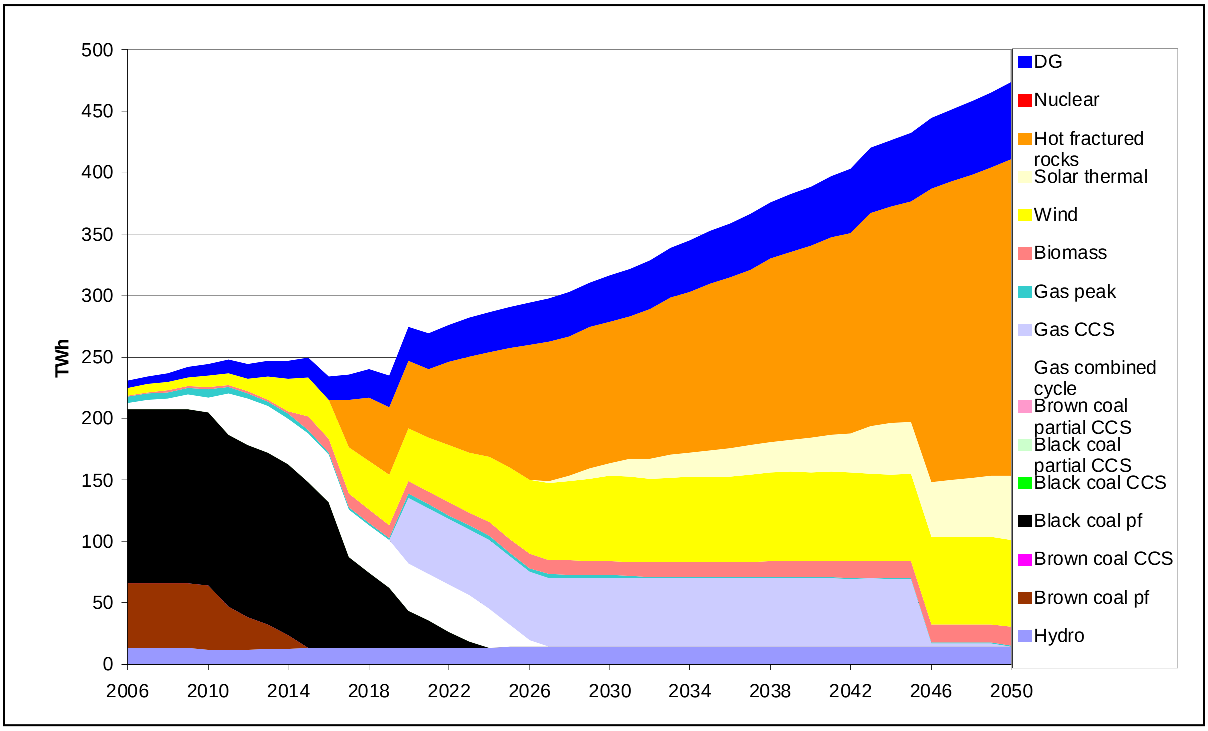


Figure 14: Distributed generation by technology: EIA reference oil price and 2000-95 emission target

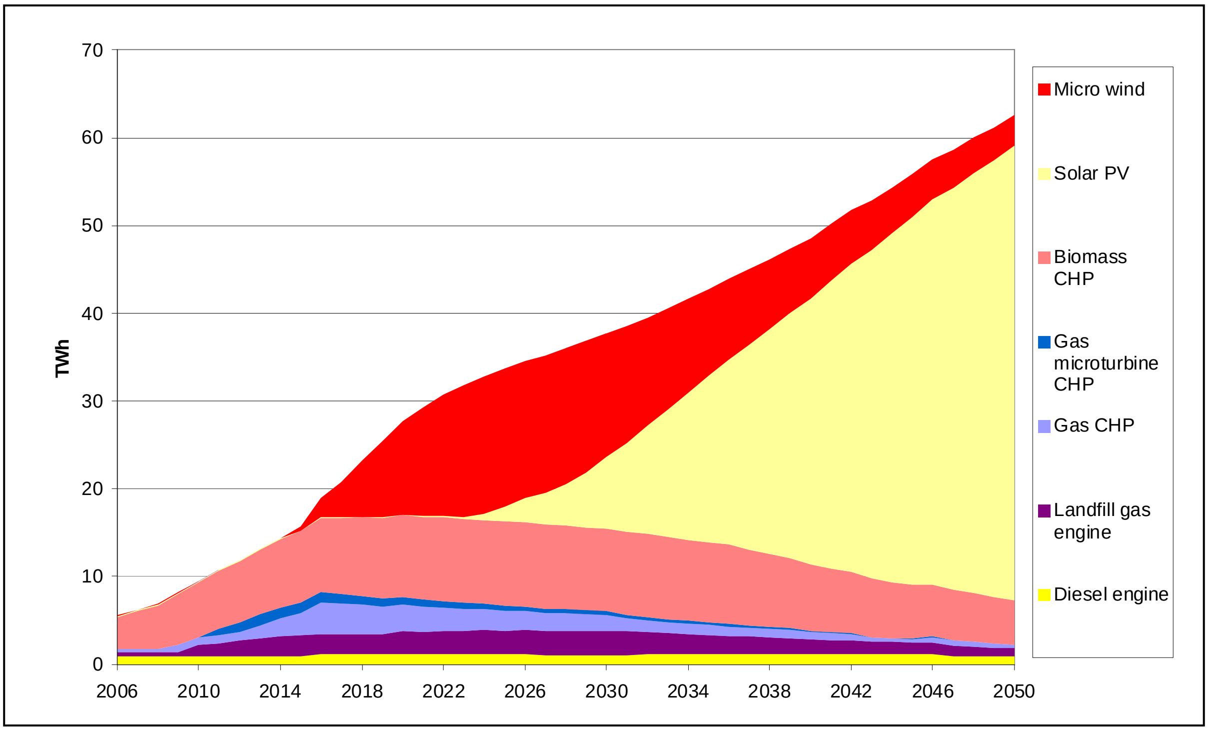


Figure 15 clearly demonstrates the rapidity with which emissions must be reduced in the 2000-95 scenario. Similar to the 2000-60 scenario the electricity and transport sector will have difficulty meeting their proportional target at lower than the external cost of abatement in the first decade of the scheme (even though that cost is higher in this scenario).

A major difference in this scenario relative to 2000-60 is that the electricity and transport sectors only enjoy a period of 10 years, between 2017 and 2027, where they are able to meet their proportional target at lowest cost relative to other sectors. After 2027, it is more cost effective for some emission abatement to occur in other sectors. This is mainly due to the higher cost of abatement in the transport sector. Even though the CO_2e permit price has risen to \$300/tCO_2e by 2050 (Figure 16), driving the electricity sector to near zero emissions, transport sector emissions remain at around 40Mt CO_2e.

Figure 15: Electricity and transport sector greenhouse gas emissions: EIA reference oil price and 2000-95 emission target

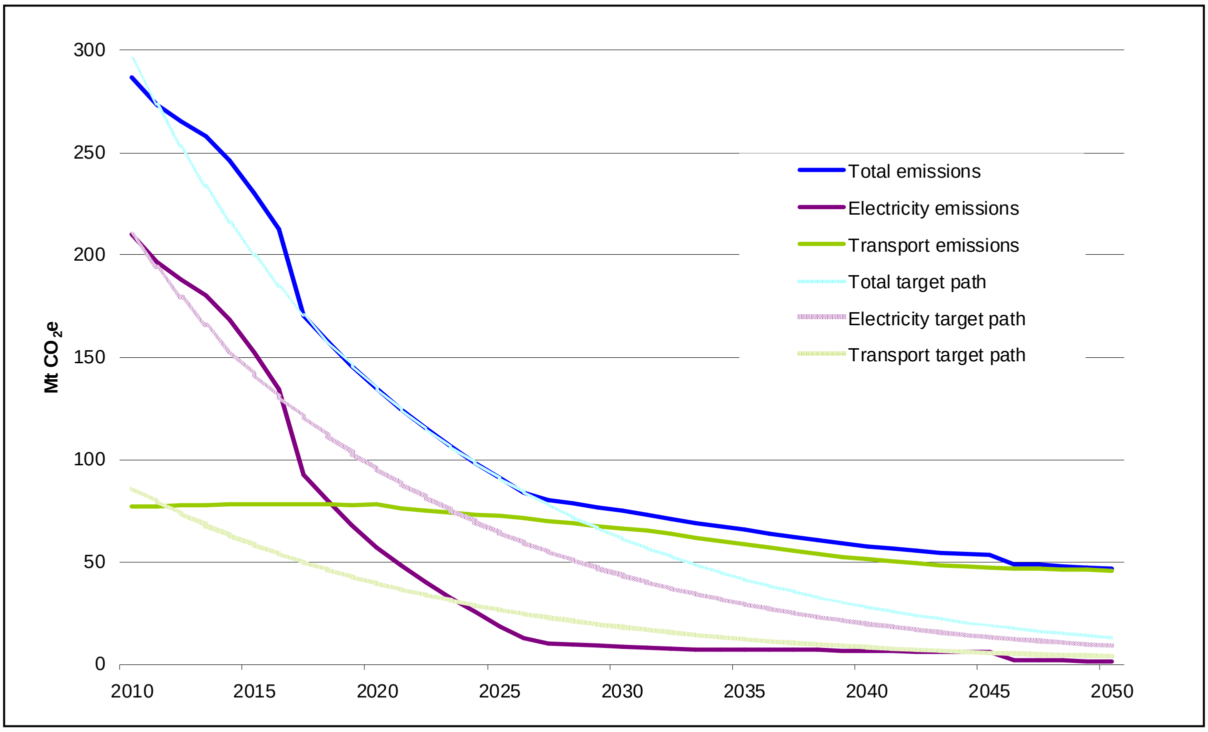
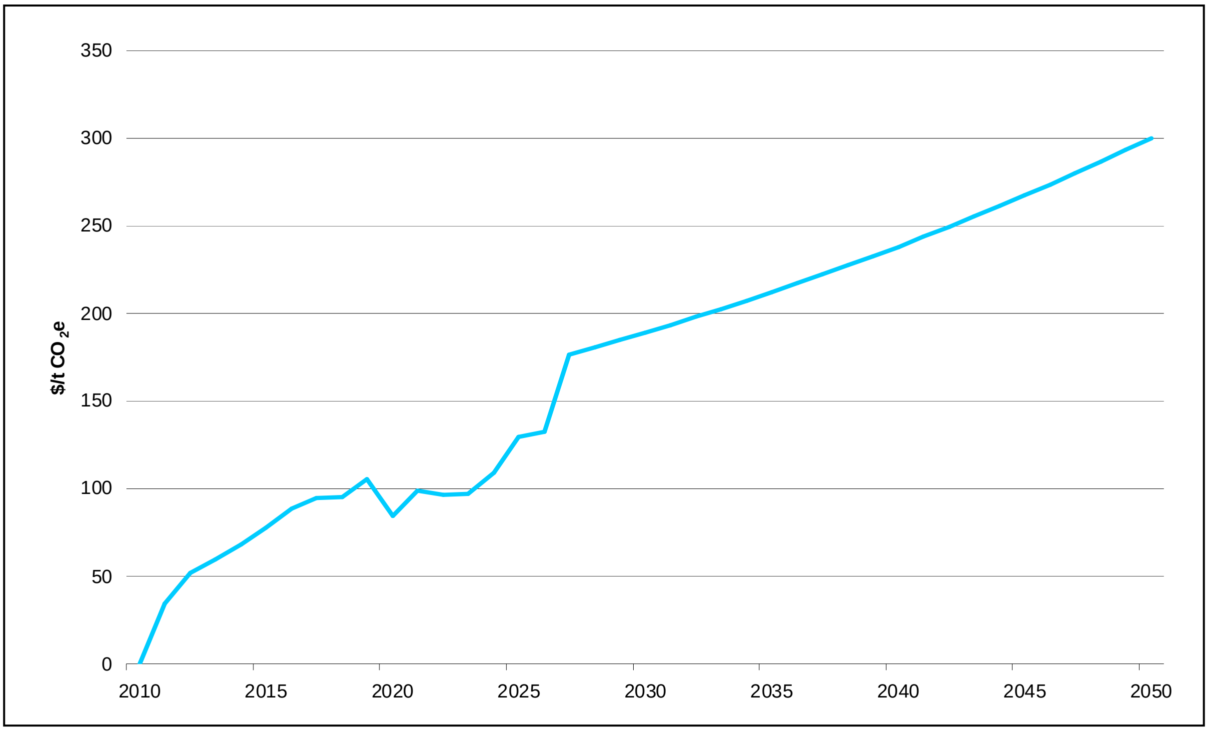


Figure 16: CO_2e permit price: EIA reference oil price and 2000-95 emission target



Moderately increasing oil price scenario: EIA high oil price

The EIA high oil price scenario represents a scenario where the oil price peaks at around US$100/bbl in 2008 and falls back to US$76/bbl by 2010. From 2011 it rises slowly to around US$100/bbl by 2030. By extrapolating this trend beyond the EIA forecast period of 2030 the price of oil is US$133/bbl in 2050 in this scenario, 50 percent higher than that in the EIA reference case.

The expectation in this scenario is that the higher oil price will encourage a greater degree of fuel and technological change than in the previous scenario where the oil price settled at a level not significantly dissimilar from today by 2050.

Emission target is 60 percent below 2000 levels by 2050

Compared to the EIA reference price scenarios the fuel mix in this scenario has a much greater amount of gas to liquids diesel (Figure 17). It also has a greater share of total diesel use reflecting the greater incentive to take up more efficient but more expensive diesel engine technology. However, some of the additional uptake in gas to liquids is at the expense of the share of coal to liquids.

The tendency to favour gas to liquids when the oil price is higher is that it gives gas the opportunity to compete. Regardless of the trend in oil prices, we have assumed in the modelling that the natural gas price will rise in Australia owing to the expected greater use of gas in electricity generation, the demand for gas as LNG in articulated truck transport and because of the rising international gas price which, in a break from the past, is expected to exert a greater influence on domestic natural gas prices. The greater interdependency of the national and international gas markets will be driven by the construction of LNG terminals that can draw from the natural gas pipeline network.

With the oil price steady in the EIA reference price the gas to liquids diesel becomes uncompetitive as the gas price rises. However, with the oil price rising in the EIA high oil price, gas to liquids is able to compete.

The EIA high oil price scenario also results in greater uptake of plug-in hybrid electric vehicles. This is the most efficient but most costly vehicle available for uptake in the model in the medium and large passenger vehicle categories.

The greater electrification of the transport vehicle fleet leads to a high level of electricity production relative to the EIA reference price scenario. However, the generation mix, including distributed generation remains largely unchanged (Figure 19 and Figure 20).

The higher oil price assists the transport sector in making a greater contribution to emission reduction relative to the EIA reference price scenario. By 2050 transport sector greenhouse gas emissions are around 50MtCO_2e compared to around 60MtCO_2e in the EIA reference price scenario. Apart form this important adjustment, other characteristics in the emission abatement path and CO_2e permit price remain very similar to the EIA reference scenario.

Figure 17: Transport sector fuel consumption: EIA high oil price and 2000-60 emission target

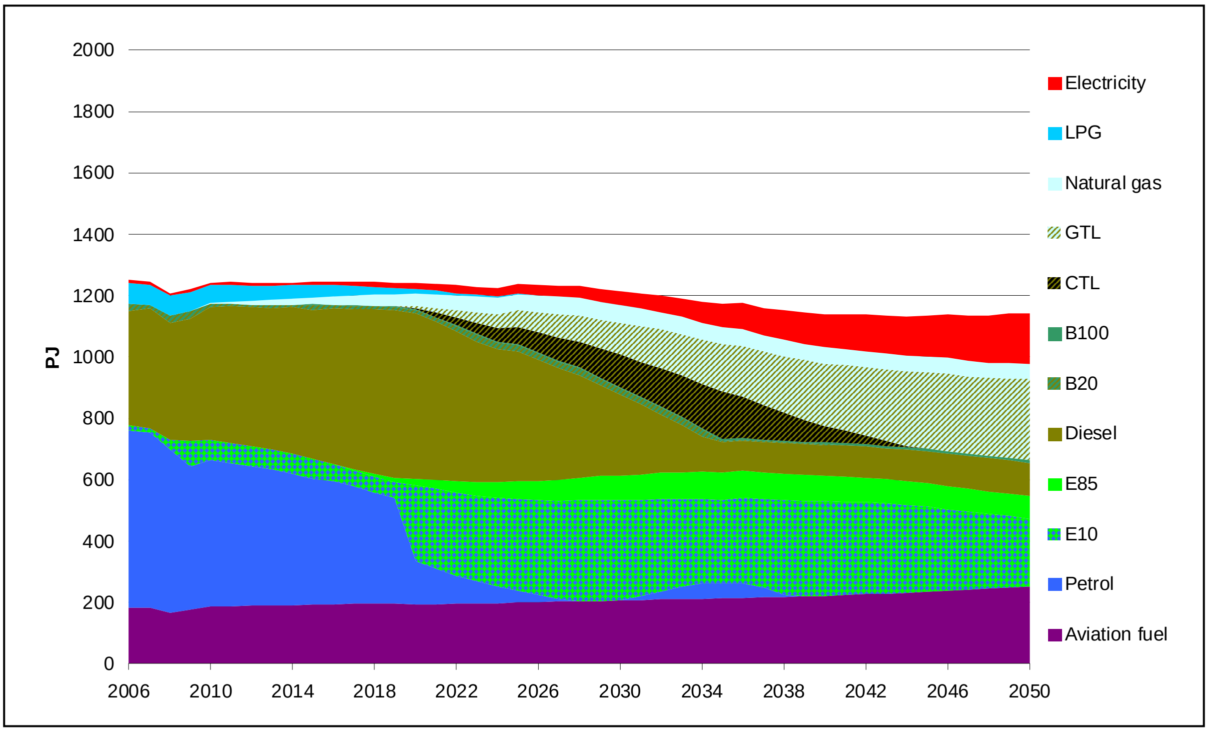


Figure 18: Share of different engine types in road kilometres travelled: EIA high oil price and 2000-60 emission target

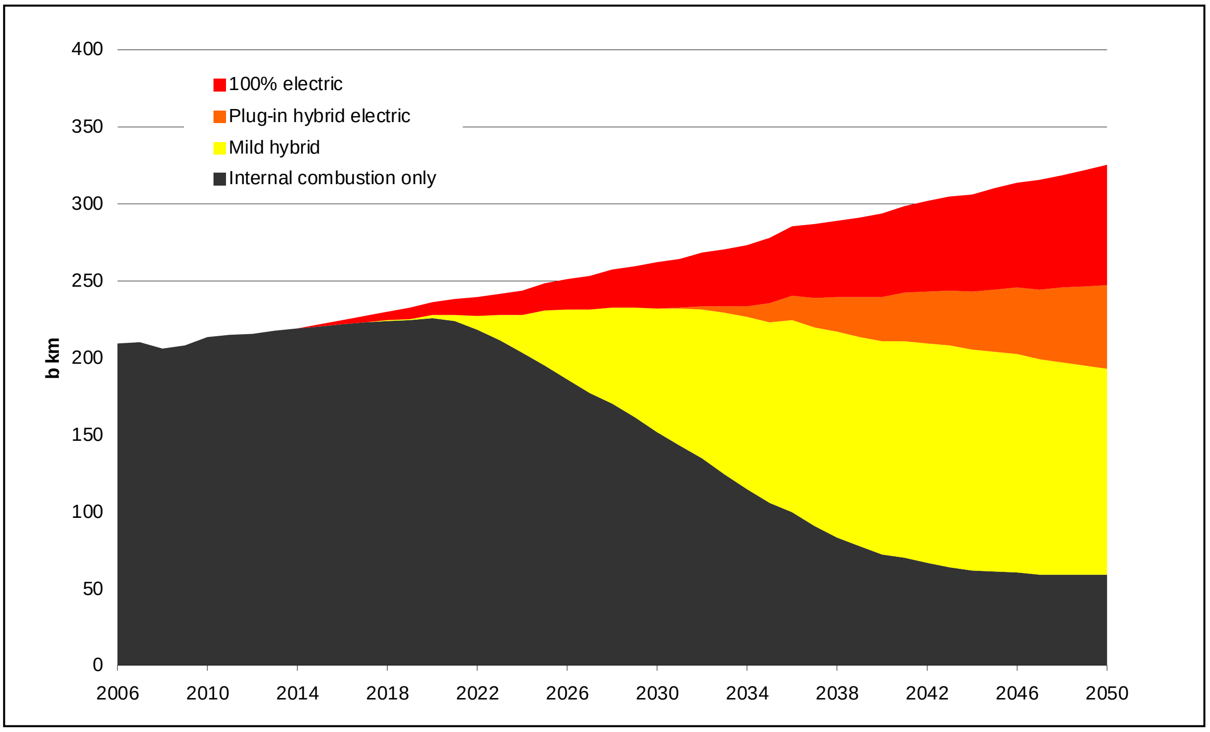


Figure 19: Electricity generation by technology: EIA high oil price and 2000-60 emission target

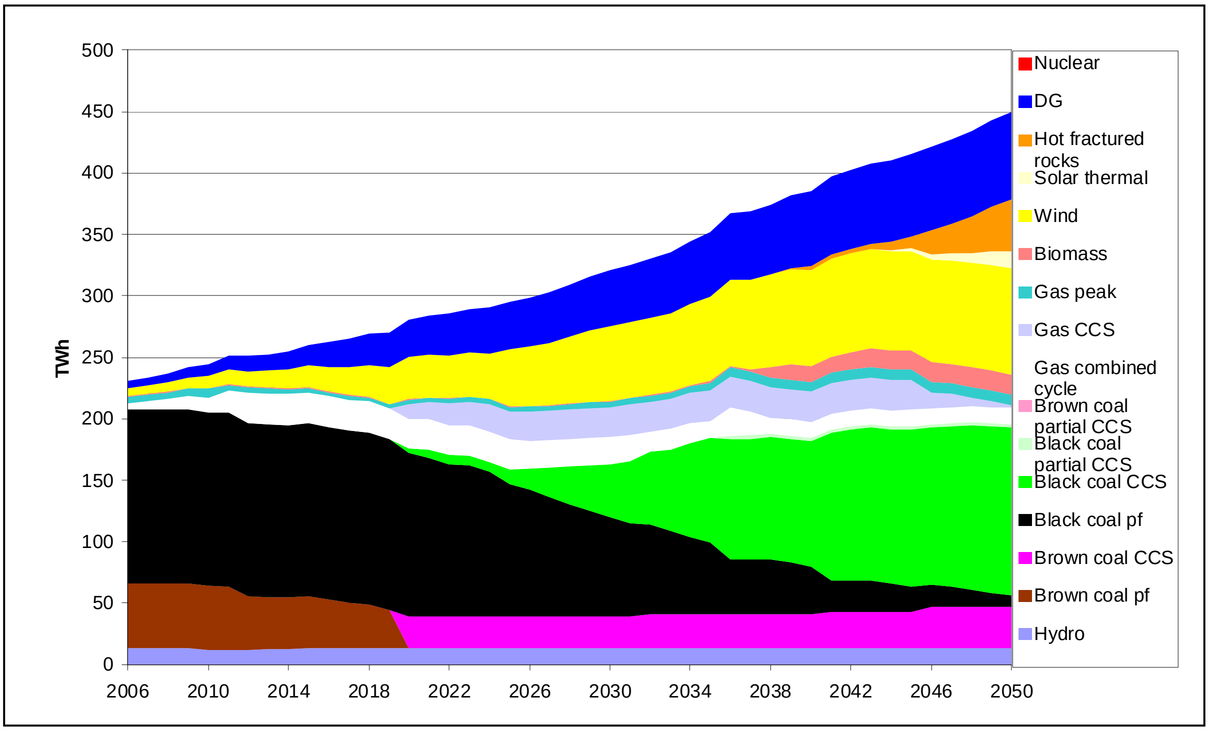


Figure 20: Distributed generation by technology: EIA high oil price and 2000-60 emission target

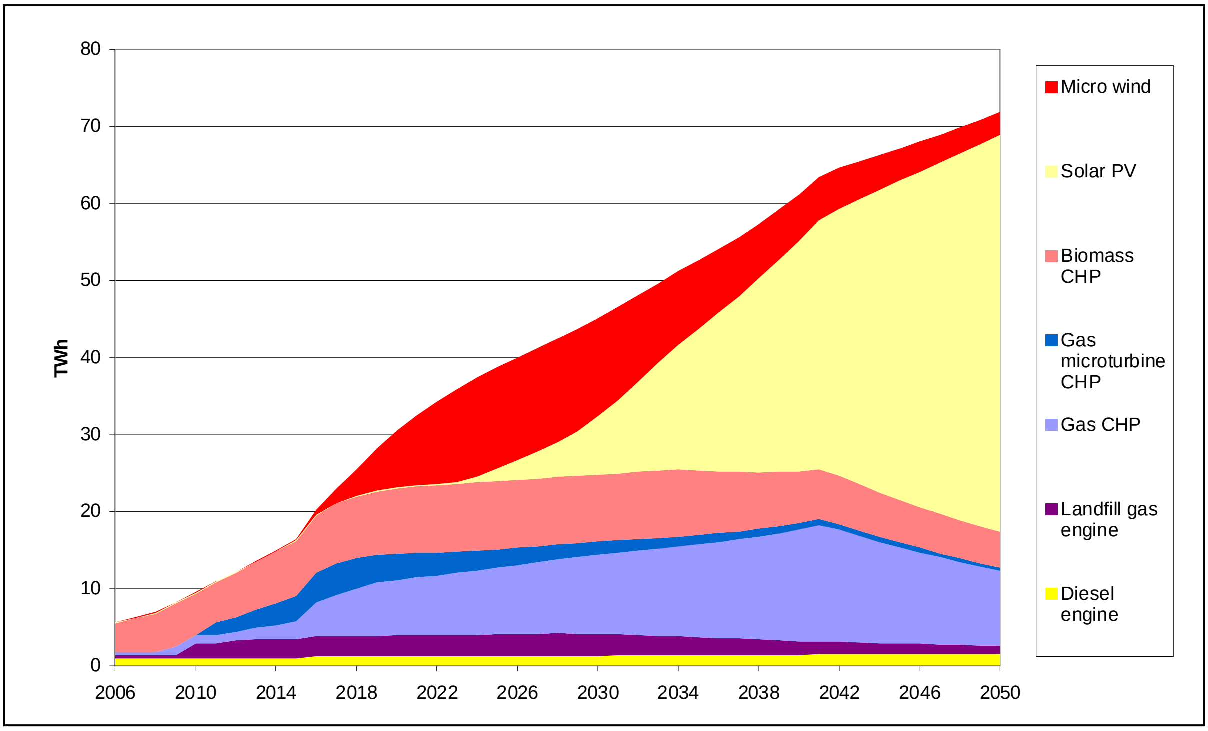


Figure 21: Electricity and transport sector greenhouse gas emissions: EIA high oil price and 2000-60 emission target

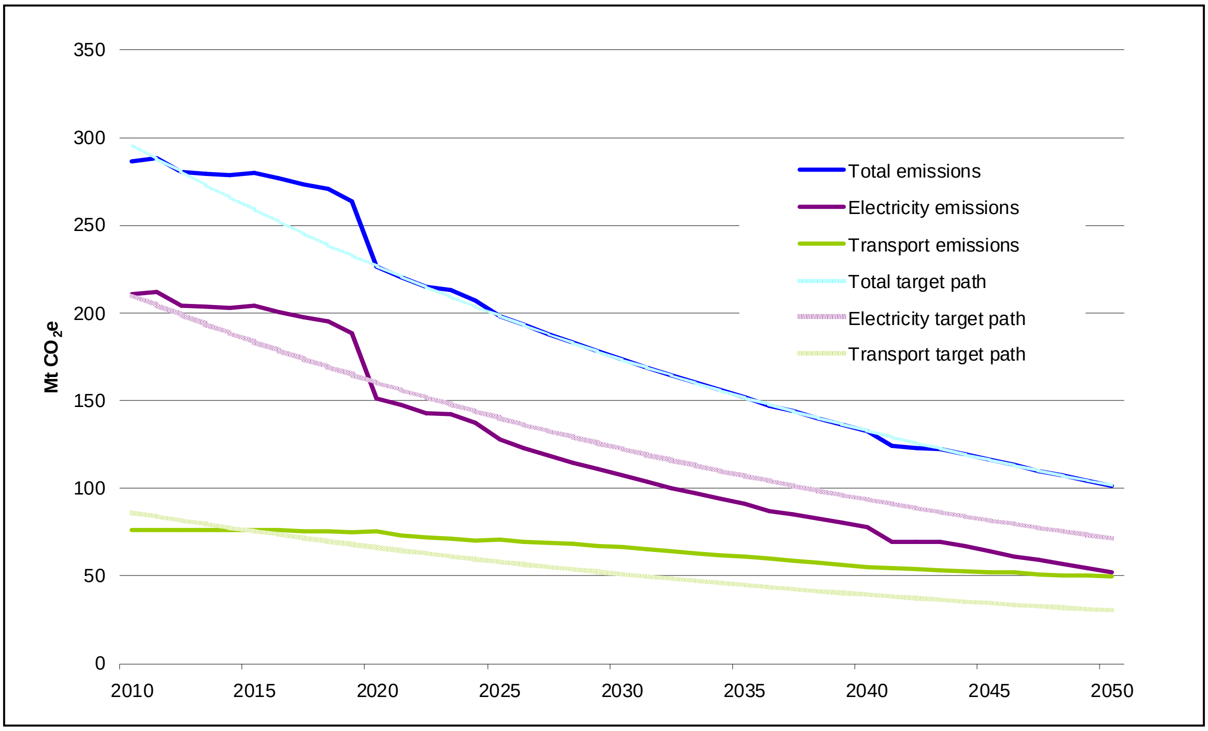
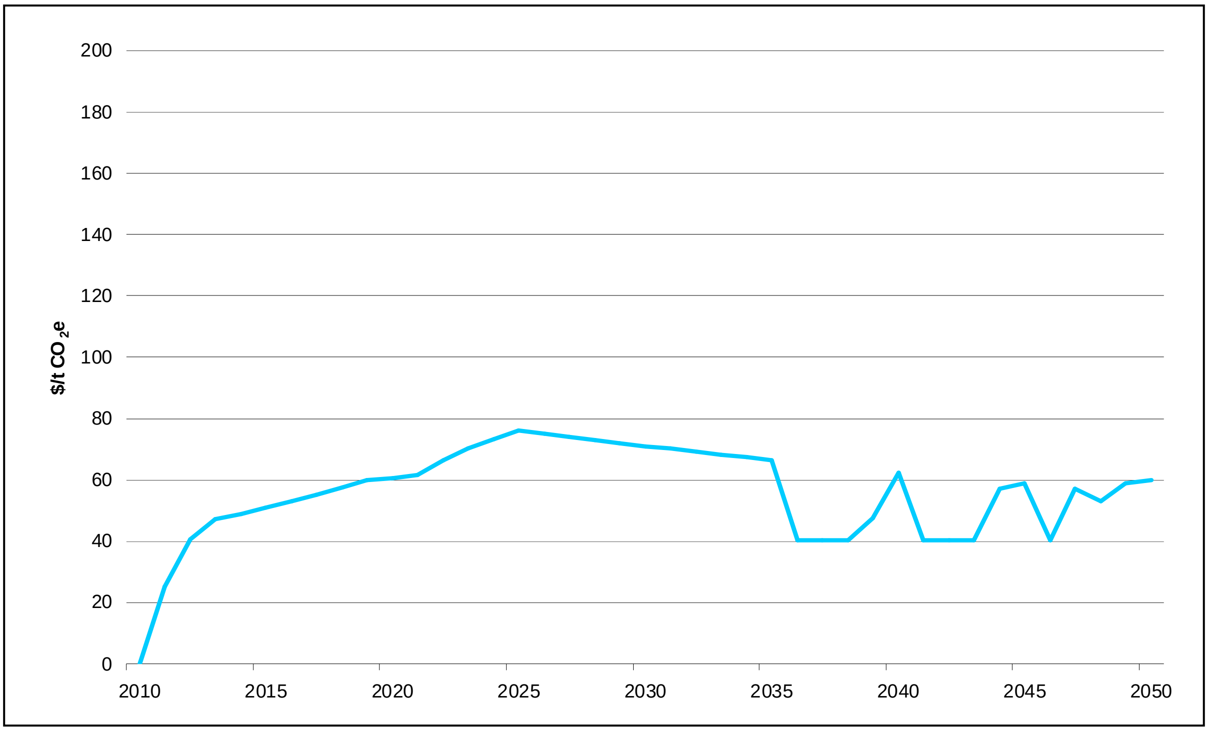


Figure 22: CO_2e permit price: EIA high oil price and 2000-60 emission target



Emission target is 95 percent below 2000 levels by 2050

When the emission target is 95 percent below 2000 levels by 2050 (2000-95) in the EIA high oil price scenario there are three significant differences in transport fuel consumption relative to the previous 2000-60 scenario. The differences are a higher share of electricity, a smaller role for coal to liquids diesel and an increased role for biodiesel blended in conventional oil-based diesel (Figure 23). These differences all reflect a trend toward lower emission intensive fuels.

The greater consumption of electricity in transport is through a very high uptake of plug-in hybrid electric vehicles which occupy nearly half of all road vehicle engine configurations (Figure 24). Higher electricity consumption in transport contributes to a higher level of electricity generation by 2050 relative to the 2000-60 scenario.

These fuel and technological changes result in emissions falling to 36MtCO_2e by 2050. However, this is still not sufficient for transport to contribute its proportionate share in emission abatement. As we have seen in all the scenario previously presented, the electricity sector would appear to have lower cost abatement options and so the electricity sector provides a greater than proportionate share of total greenhouse gas reduction.

As was observed in the case where the EIA reference price was assumed, even with the EIA high oil prices driving additional greenhouse gas abatement, together the electricity and transport sectors only achieve their proportionate emission abatement target between 2017 and 2027 (Figure 27). During most other periods, abatement is assumed to be achieved in other sectors and as a result the external CO_2e permit price prevails which rises from \$40/tCO_2e in 2010 to \$300/tCO_2e in 2050 (Figure 28).

Figure 23: Transport sector fuel consumption: EIA high oil price and 2000-95 emission target

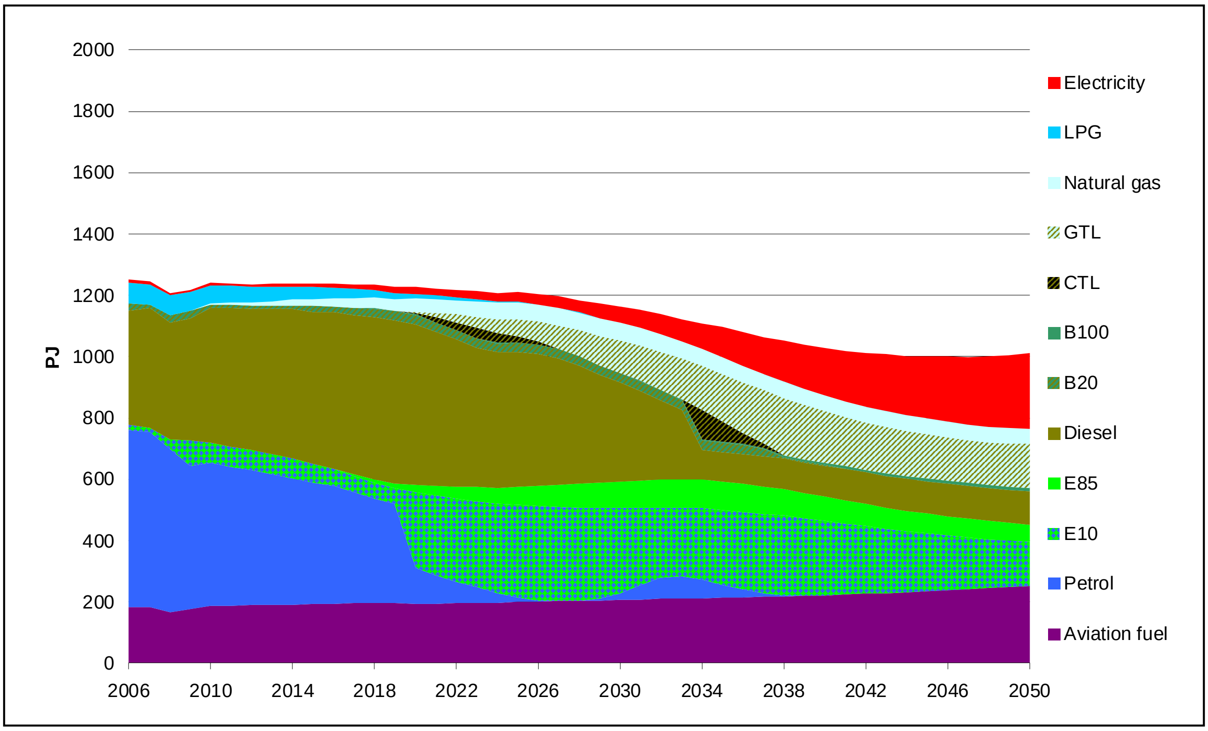


Figure 24: Share of different engine types in road kilometres travelled: EIA high oil price and 2000-95 emission target

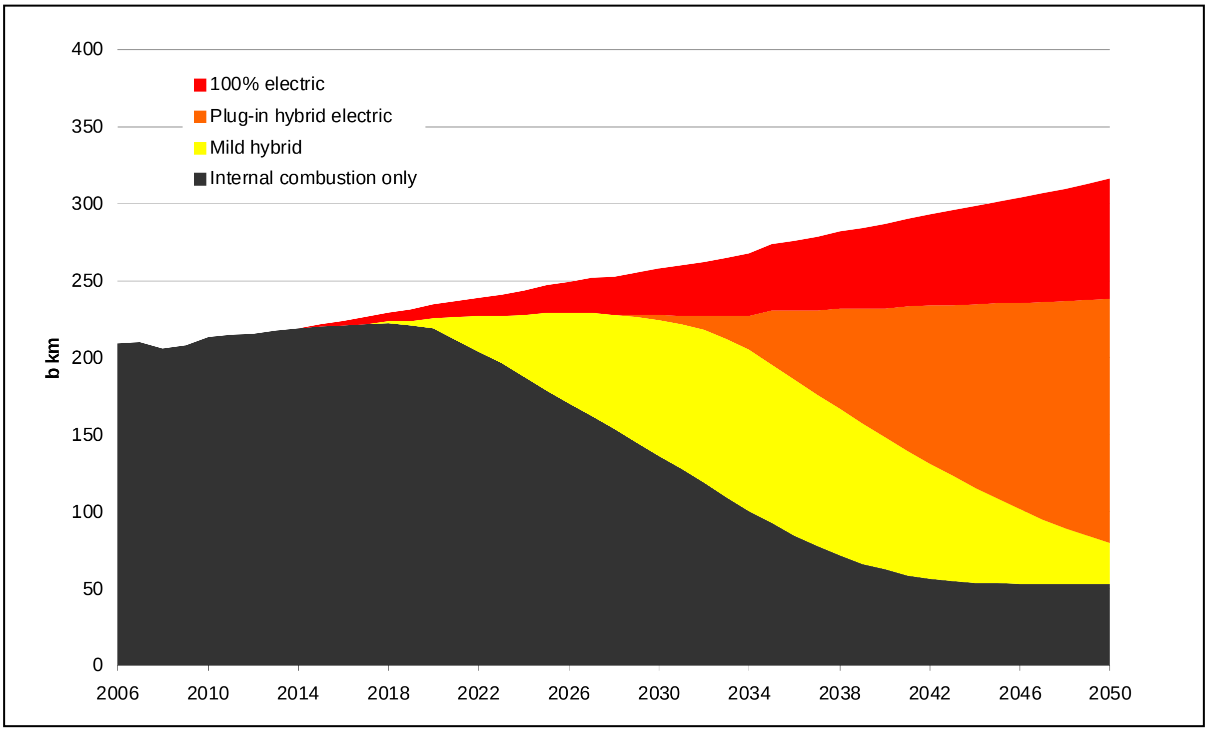


Figure 25: Electricity generation by technology: EIA high oil price and 2000-95 emission target

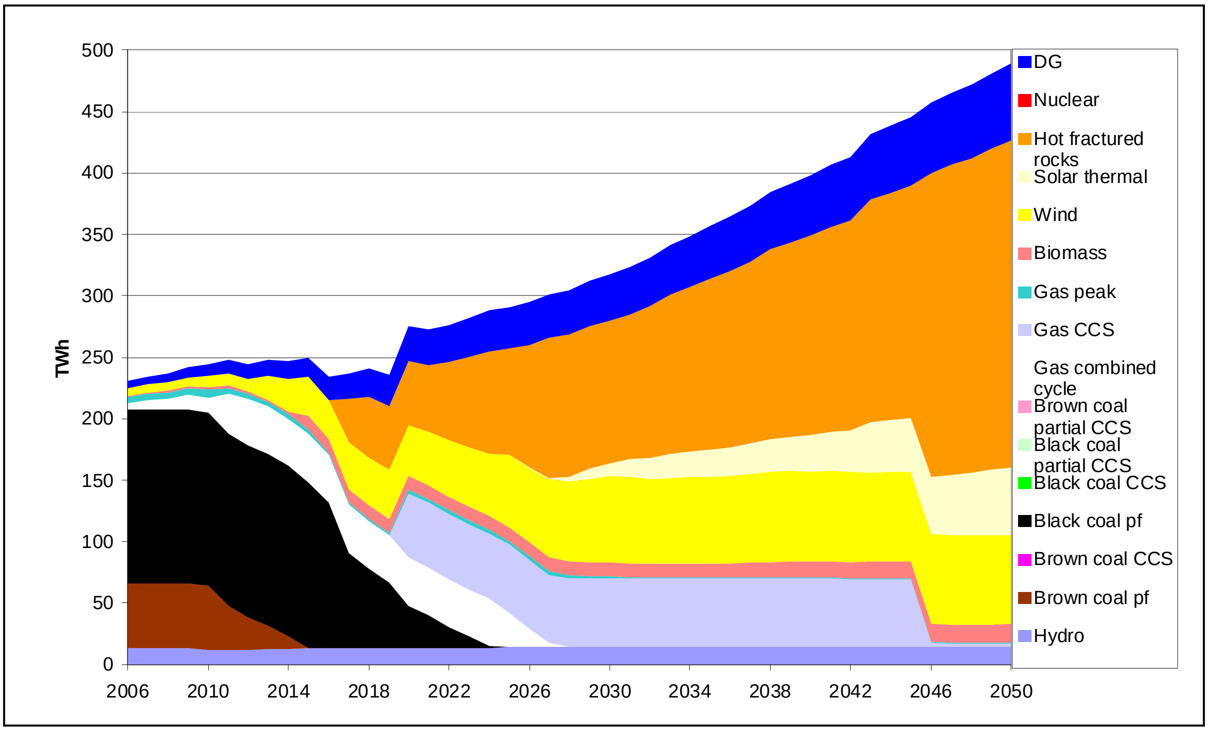


Figure 26: Distributed generation by technology: EIA high oil price and 2000-95 emission target

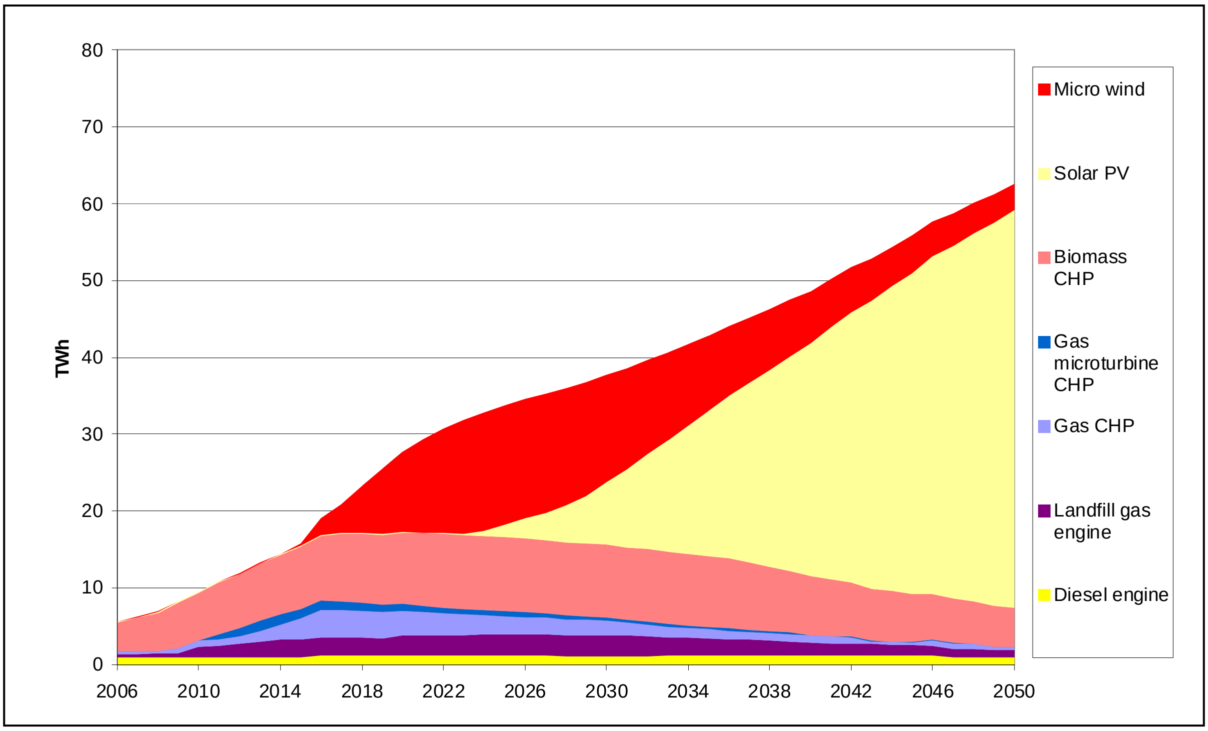


Figure 27: Electricity and transport sector greenhouse gas emissions: EIA high oil price and 2000-95 emission target

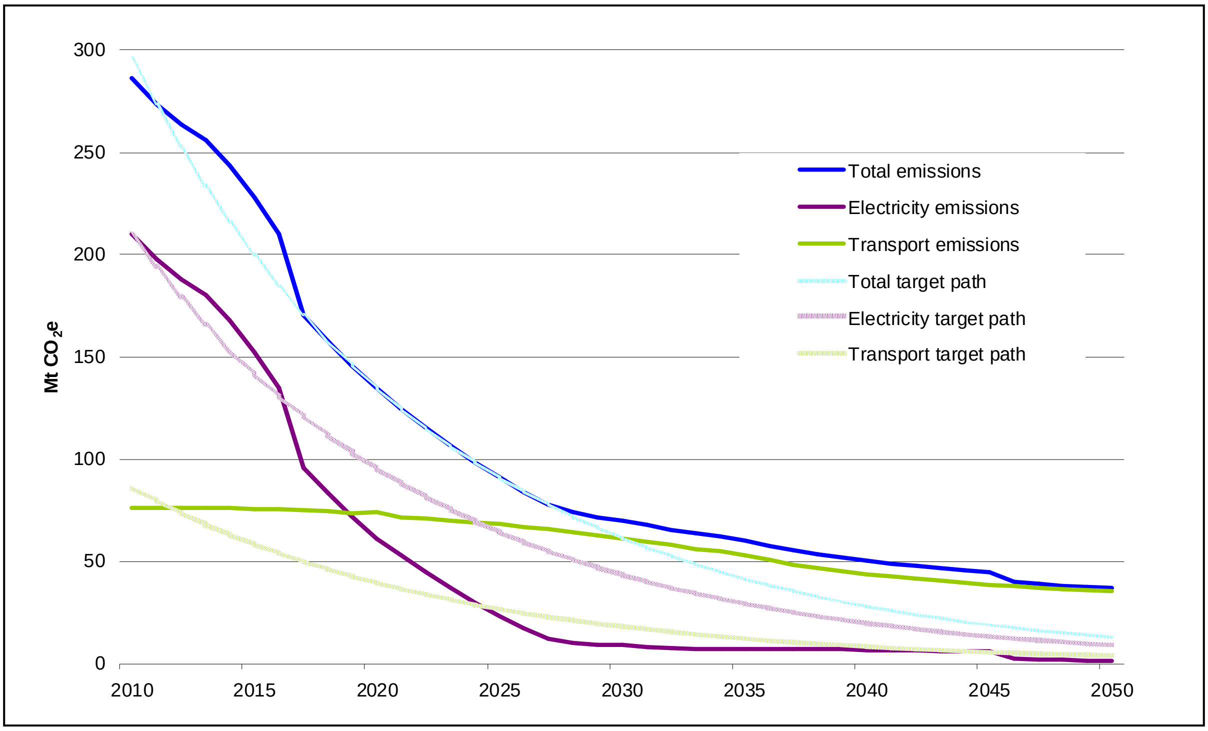
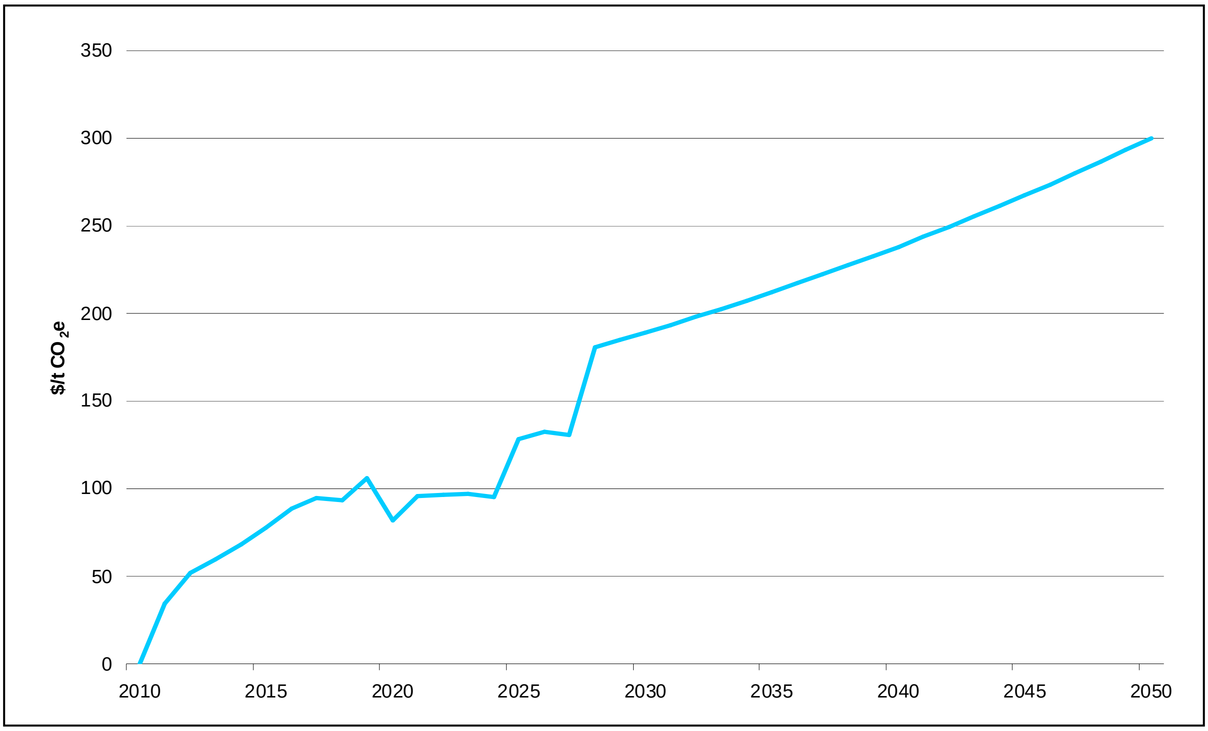


Figure 28: CO2e permit price: EIA reference oil price and 2000-95 emission target



Declining oil supply

Based on PONL (2005) if oil production follows the peak oil theory the global rate of decline in oil and oil products production is expected to be around 3 percent per annum from 2010. In these circumstances, there is no guarantee that Australia will have a proportional access to the decline in oil supplies. As a best case scenario we assume Australia does receive its proportionate share.

In applying the best case 3 percent rate of decline we assume that the air, rail and sea transport sectors have preferential access to Australia's share of oil products. While these modes shift to biofuels, greater electrification (rail) and synthetic fuels and are subject to some reduction in demand for travel via a price response, oil based fuel use in these sectors does not radically decline. As a result of the continuing use of oil based fuel products in the non-road sectors the rate of decline in oil products experienced by the road transport sector is 4 percent for the first two decades and worsening into the future.

In a worst case scenario we assume that Australia does not receive its proportionate share of oil product. In this case we apply a oil product supply decline rate of 10 percent directly to the road transport sector (implying a better than 10 percent rate overall when preferential access by the non-road sector is taken into account). Note, at this rate, oil product supply to the road transport sector is all but exhausted by 2035.

In all of the declining oil supply scenarios the oil supply is assumed to decline starting from the year 2010. However, it should be noted that there a wide variety of views in regard to when global oil production will peak.

In terms of technological availability we assume that any type of hybrid electric vehicle is able to be purchased immediately in any volume at the costs detailed in Appendix A. However, as the modelling shows, these vehicles still consume oil based products and so are not necessarily the solution of choice.

Aside from electrical hybridisation the main options for completely avoiding consumption of oil based products are full electrification, LPG and natural gas vehicles, biofuels and synthetic fuels. In terms of biofuels and synthetic fuels we maintain the assumption as applied in the other core scenarios that large volumes of these fuels will not be available until post 2020 (2015 for biodiesel). Therefore in constructing our technology response scenarios we focus on the number of fully electric, natural gas and LPG vehicles able to be purchased each year. Table 3 shows the specific assumptions relating to the maximum number of alternative fuel vehicles that can be purchased each year.

Table 3: Declining oil scenario assumptions

Scenario	Minimum rate of decline in oil based fuel consumption	Maximum rate of expansion in total production of alternative fuel vehicles [1]
Slow decline in oil supply with fast rate of increase in availability of alternative fuels and vehicles	3 percent per annum all modes 4 percent per annum road transport fuels	300,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Fast decline in oil supply with slow rate of increase in availability of alternative fuels and vehicles	6 percent per annum all modes 10 percent per annum road transport fuels	15,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter

1. Includes LPG, natural gas and fully electric vehicles. Allowable hybrid electric vehicle uptake is unlimited

Figure 29 and Figure 30 show the fuel consumption mix under the two declining oil scenarios for the 2000-60 emission target. In each scenario the market response is to take up as many non-oil consuming alternative fuel (LPG, natural gas and electric) vehicles as possible and if insufficient reduce total fuel usage via less travel.

In the “slow oil decline fast technology response“ scenario sufficient alternative fuel vehicles are available such that only a moderate reduction in fuel consumption is required. However in the much more challenging “fast oil decline slow technology response“ scenario, total transport fuel consumption must fall by one third by 2020 before sufficient volumes of alternative fuels and vehicles are available to substitute for the reduced availability of oil products. Note that in the “fast oil decline slow technology response“ scenario, ethanol is not taken up. This is because the model only allows for a maximum 85 percent blend and petrol is too scarce to find enough to blend it with. It is possible that this blending ratio would be relaxed in reality.

Figure 31 compares these two fuel consumption profiles and also includes the scenarios where the emission reduction target is 95 percent below 2000 levels by 2050 (2000-95). It indicates that the deeper emission target of 2000-95 forces some additional reduction in fuel consumption over and above the impact of the oil product supply constraint.

Figure 29: Transport sector fuel consumption: Slow decline in oil supply, fast technology response and 2000-60 emission target

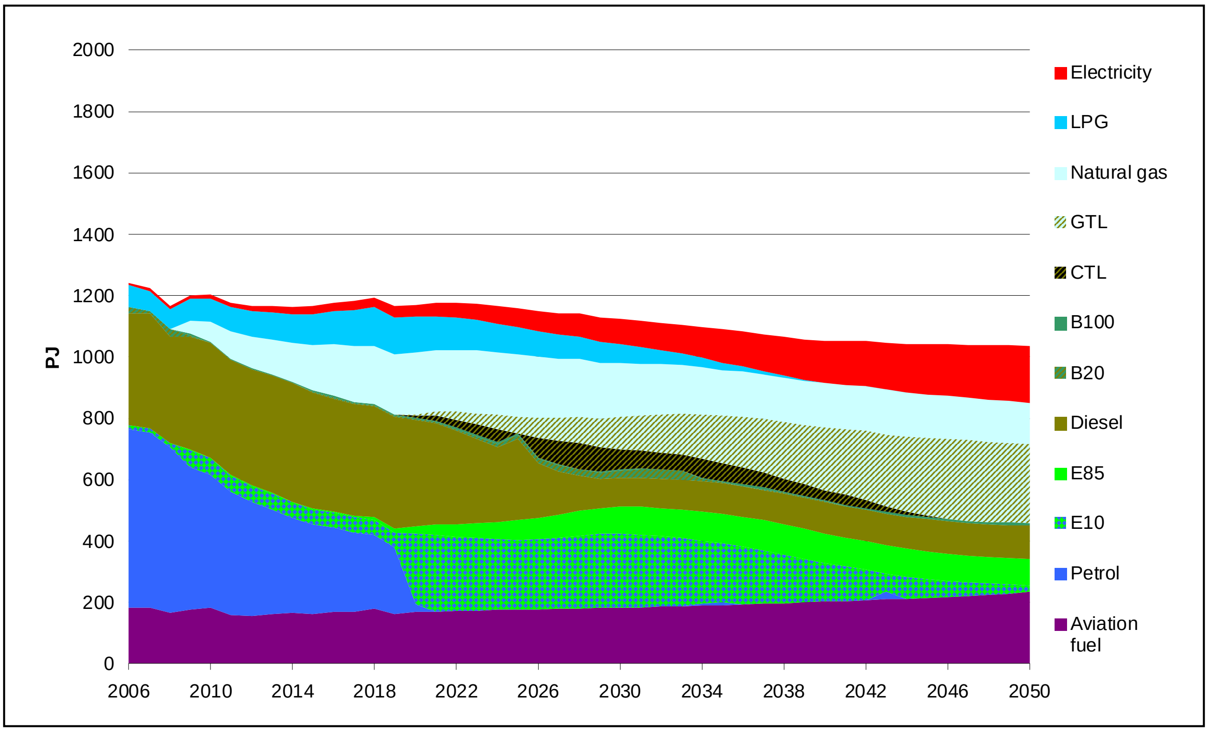


Figure 30: Transport sector fuel consumption: Fast decline in oil supply, slow technology response and 2000-60 emission target

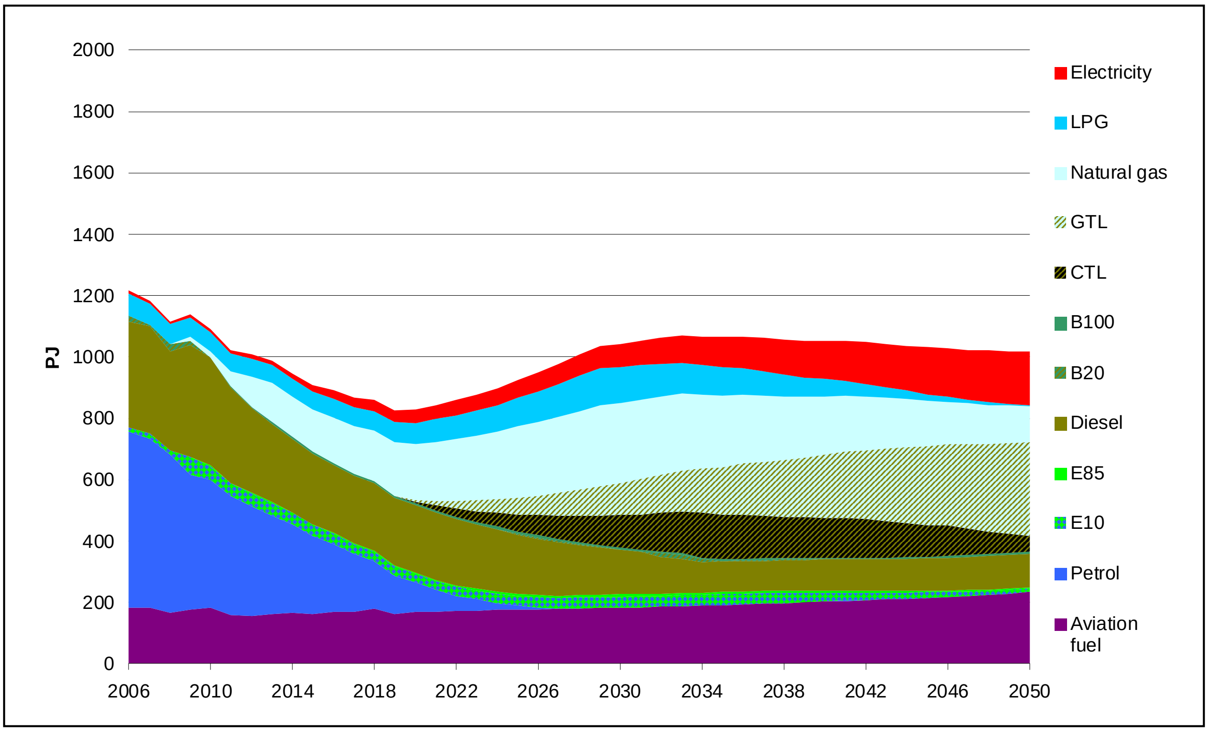


Figure 31: Comparison of transport sector fuel consumption under declining oil scenarios

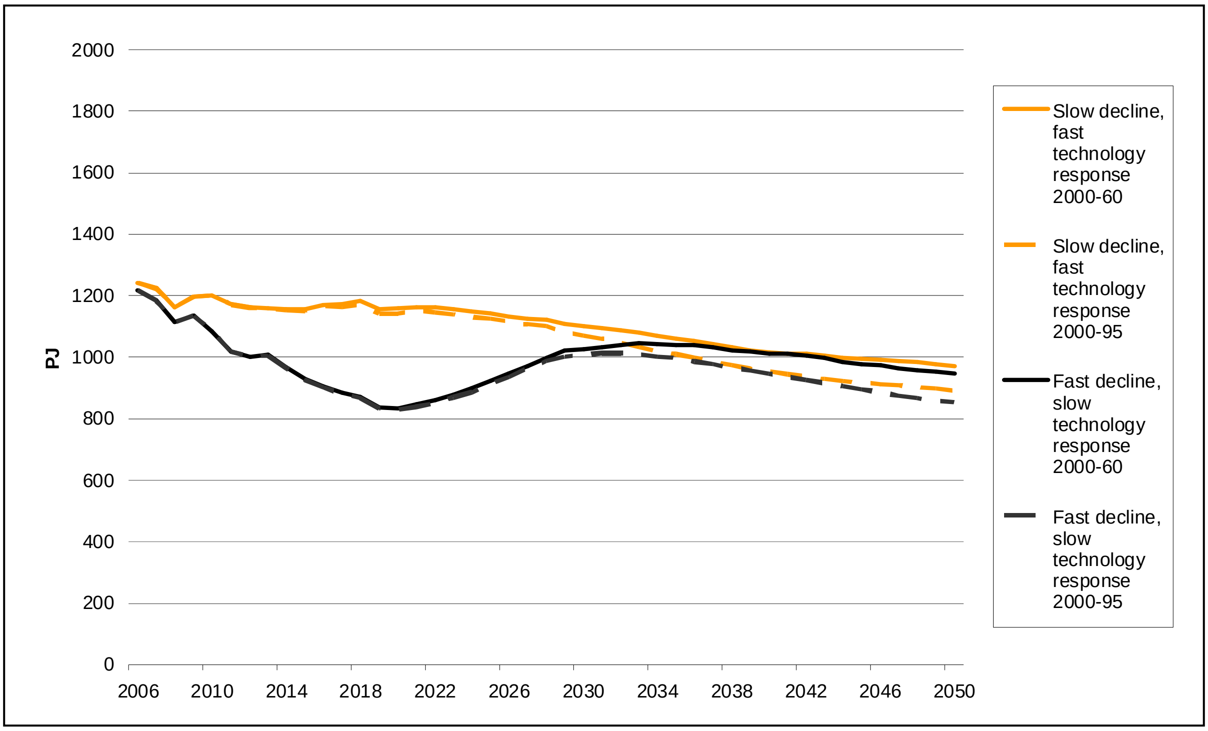


Figure 32: Comparison of petrol price required to ration demand in declining oil scenarios

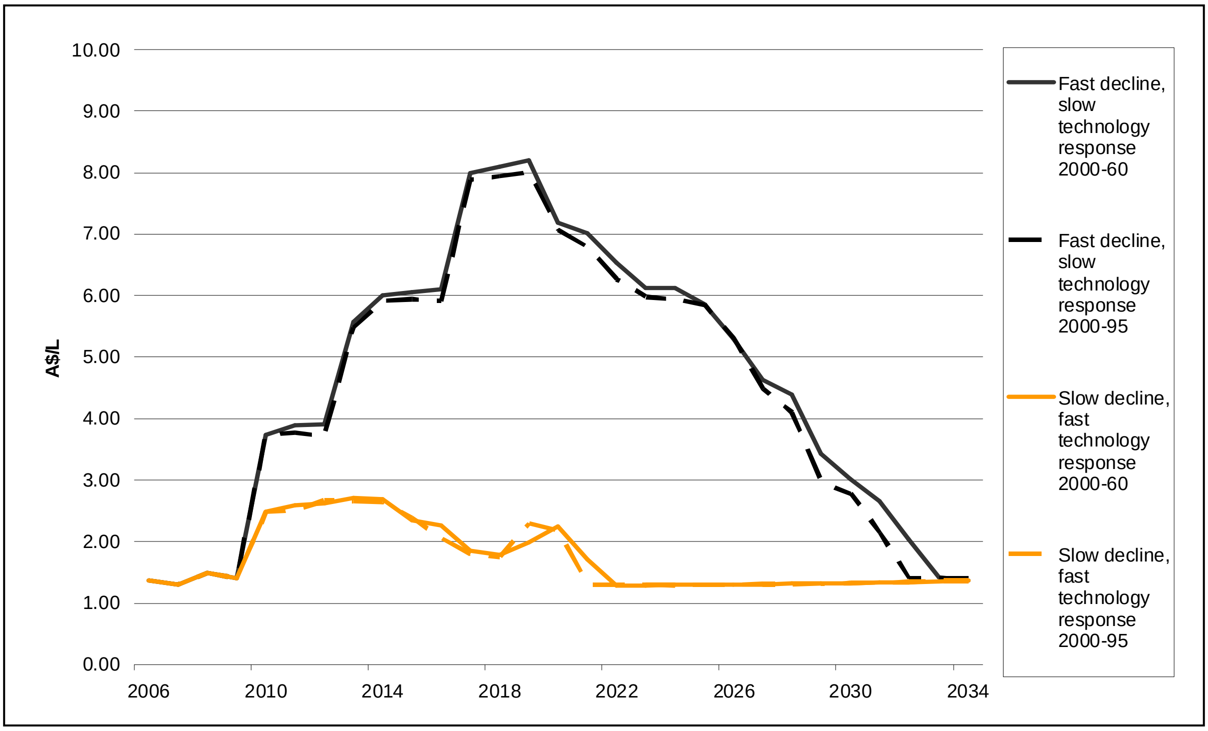


Figure 32 shows the petrol price that the model has calculated was required each year to constrain oil product consumption at the scenarios defined level of availability. This can be interpreted as the price consumers would have been willing to pay to be indifferent between oil based petrol/diesel and the alternatives. As such it provides some indication of the prices consumers might pay were these scenarios to eventuate. However, it does not take into account the effect of demand from the rest of the world which could put further pressure on prices. To calculate a more accurate estimate might require a model of the world transport market.

The trend indicates a price bubble beginning from 2010 when the oil supply is assumed to decline. In the “slow oil decline fast technology response“ scenario the price of petrol peaks at $2.60/L. In the “fast oil decline slow technology response“ scenario the price of petrol peaks at $8.20/L. In both scenarios the oil price bubble does not permanently decline until 2020 when biofuels and synthetic fuels from coal and gas are assumed in the modelling to be available at large scale. If these fuels could be made available sooner in reality then the bubble could reduce faster.

Beyond 2035 the modelling is less clear on price of oil based fuel products and so the results are not shown. In the “fast oil decline slow technology response“ scenario oil based fuel products are almost exhausted and theoretically the price is infinite (and the modelled prices generally increase in a vertical fashion). More likely at this point the transport system will have all but moved-on from oil based fuels on a permanent basis and so the price of oil products will be largely irrelevant. In the “slow oil decline fast technology response“, there is some scope to continue use of petroleum but this quickly leads to a second price bubble as oil based fuel products continue to decline.

Figure 33, Figure 34, Figure 35 and Figure 36 show the emission impact of the declining oil supply scenarios for each of the 2000-60 and 2000-95 emission target scenarios. They indicate that in the event of declining oil supply it will be easier for the transport sector to contribute to emission reduction in the first two decades of an emission trading scheme.

However, there is also a tendency for some of the emission reduction to be undone as the fuel supply situation eases, particularly in the “fast oil decline slow technology response“ scenario. In this scenario emissions start to increase from 2020 because consumers are simply responding to the greater availability of fuels and travelling more and the prevailing CO_2e permit price is not enough to offset the falling cost of fuel.

The electricity generation mix for the declining oil supply scenarios is not shown because there is no significant change in the electricity generation fuel mix. The only observable difference is a slight increase in electricity generation due to the accelerated uptake of electricity in transport in these scenarios.

Figure 33: Electricity and transport sector greenhouse gas emissions: Slow decline in oil supply, fast technology response and 2000-60 emission target

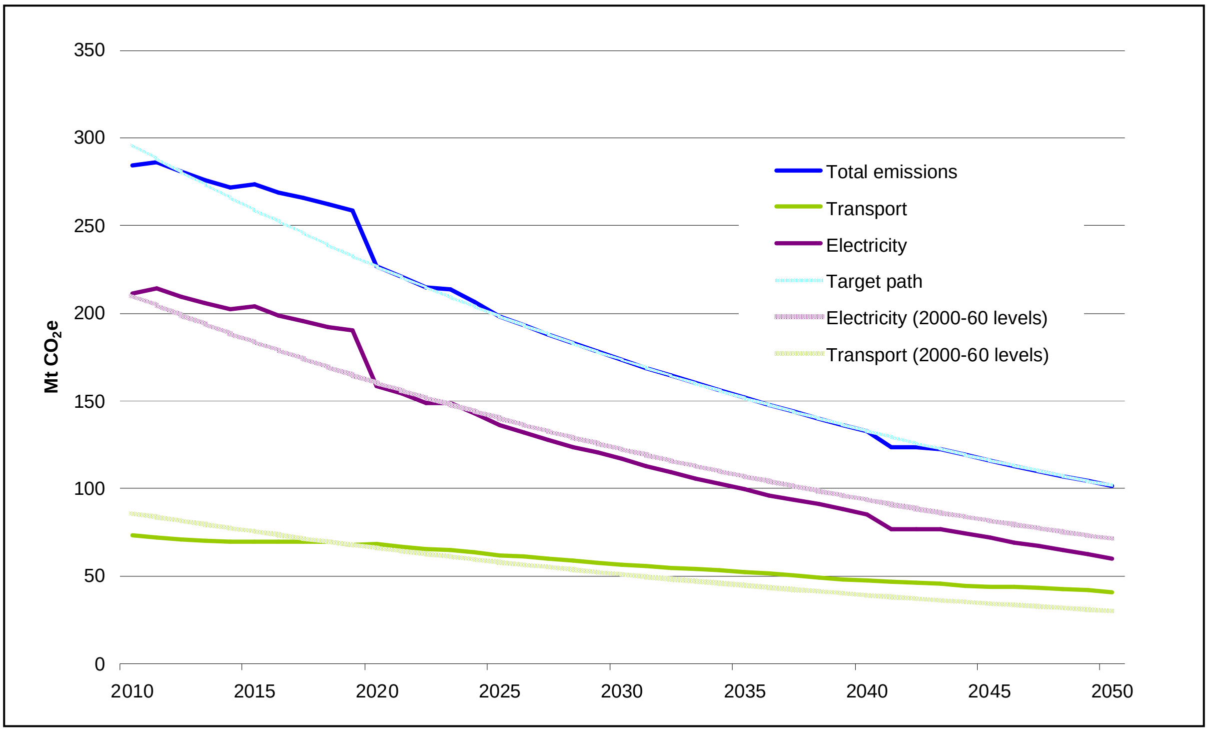


Figure 34: Electricity and transport sector greenhouse gas emissions: Fast decline in oil supply, slow technology response and 2000-60 emission target

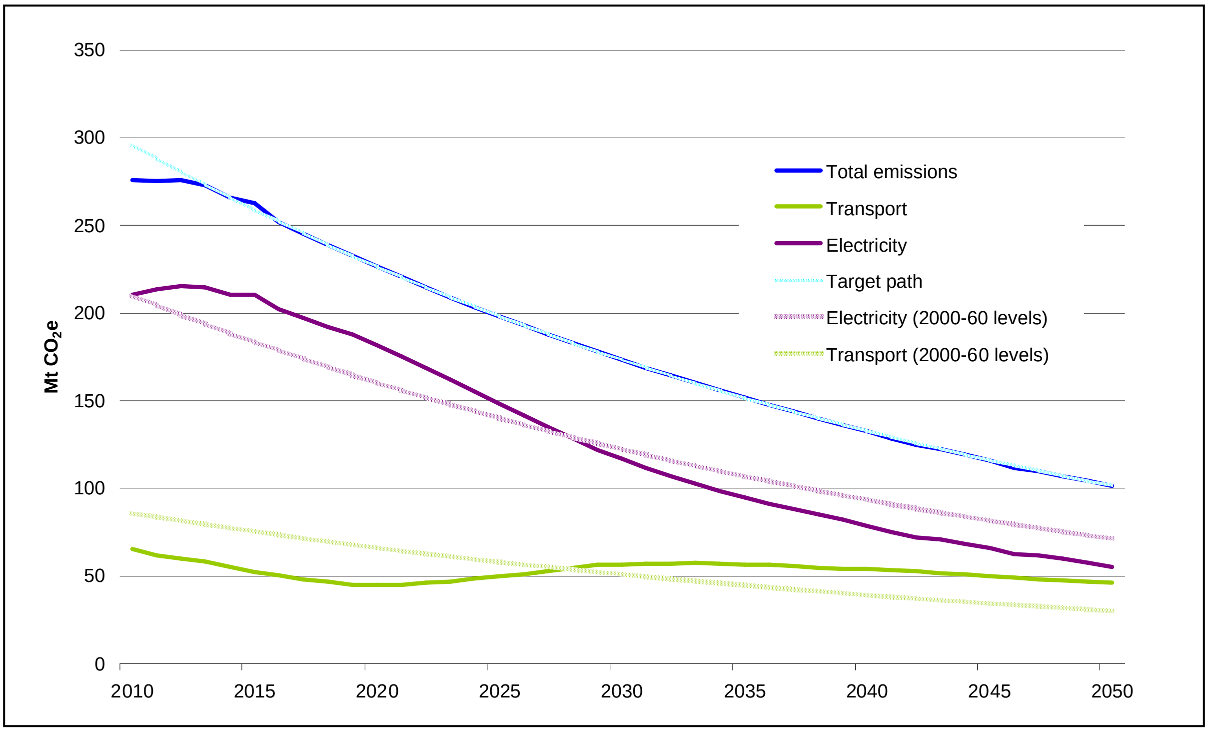


Figure 35: Electricity and transport sector greenhouse gas emissions: Slow decline in oil supply, fast technology response and 2000-95 emission target

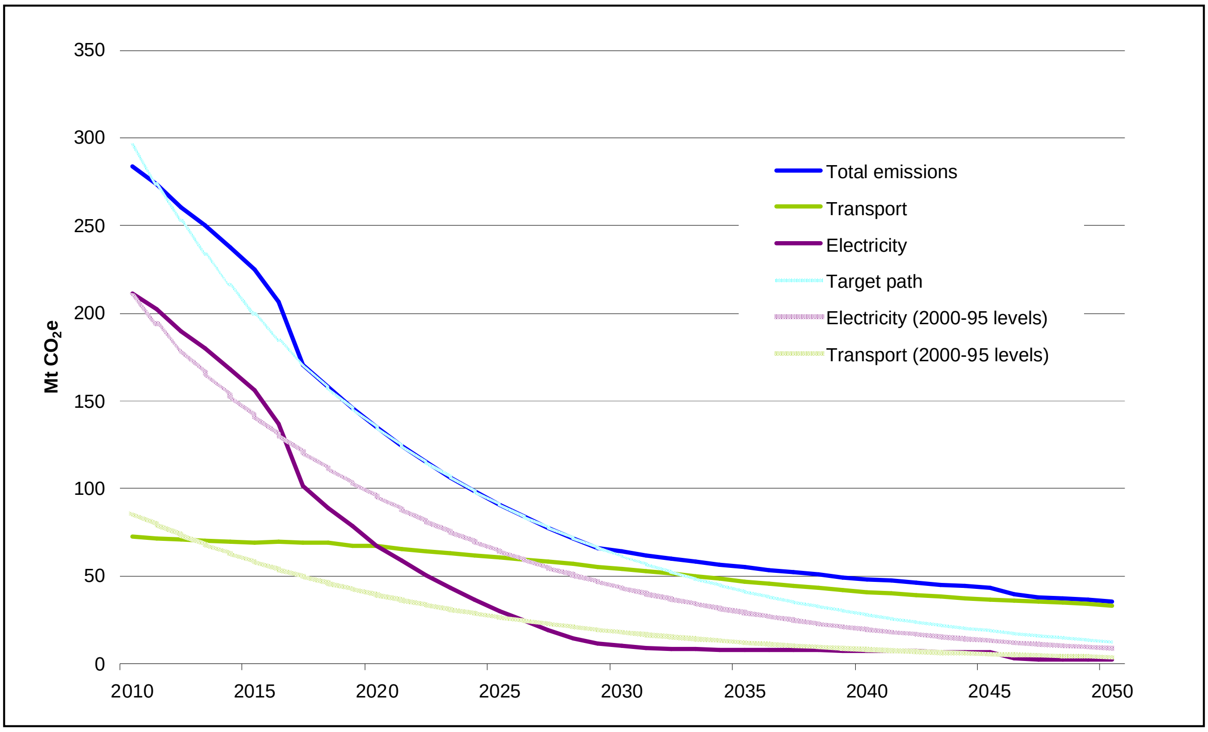
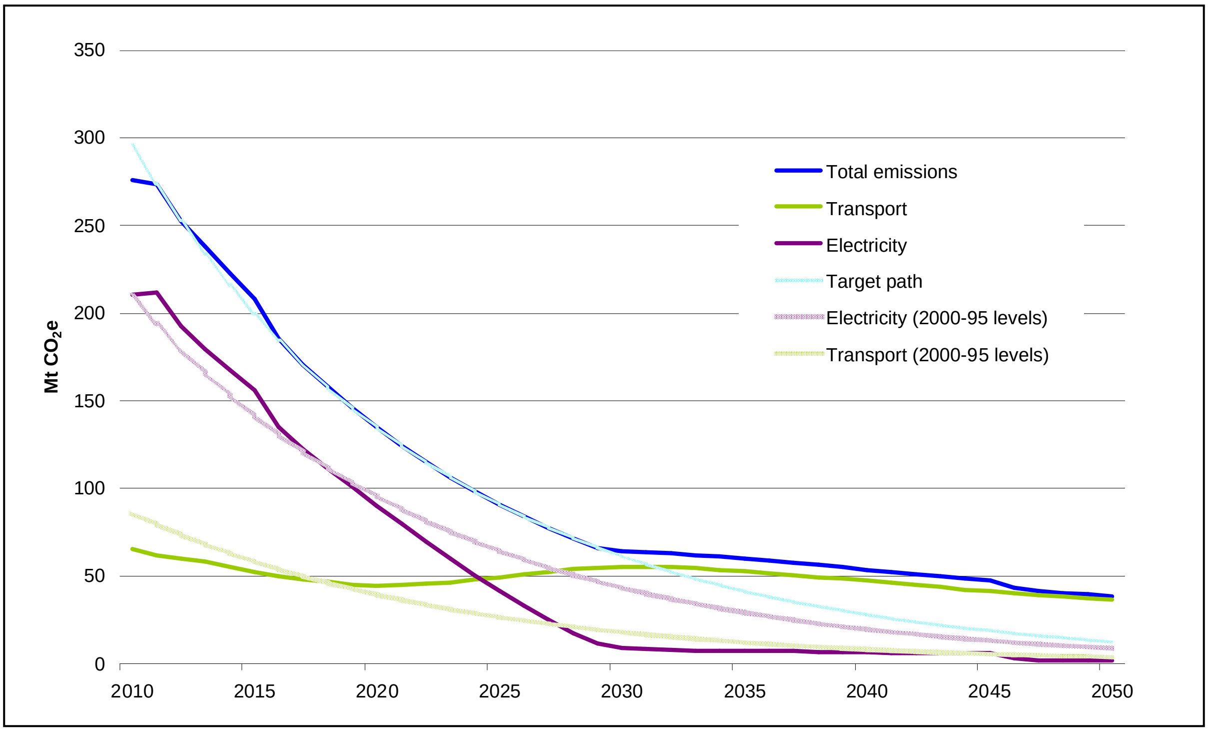


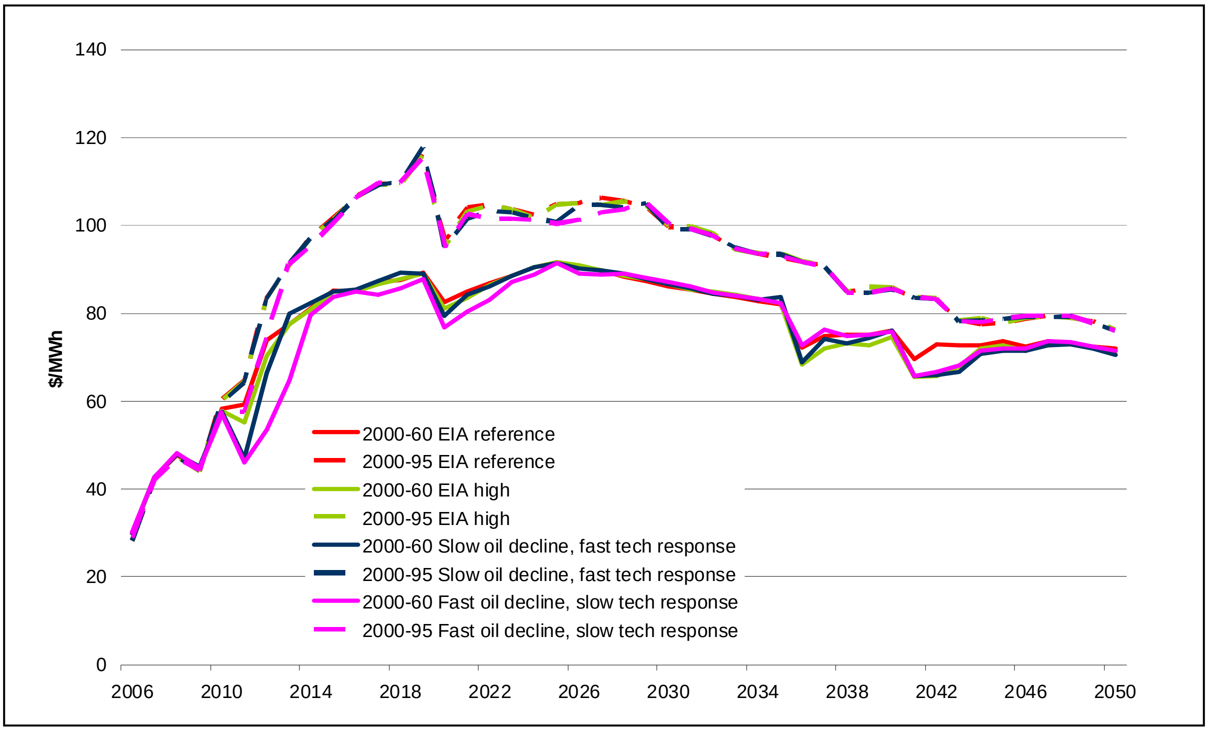
Figure 36: Electricity and transport sector greenhouse gas emissions: Fast decline in oil supply, slow technology response and 2000-95 emission target



Summary of price projections across the core scenarios

Wholesale electricity prices are projected to increase to $90 and $120/MWh for the 2000-60 and 2000-95 emission target core scenarios by 2020 before declining for the remainder of the projection period as lower cost low emission intensive electricity generation technologies become available. The variation in international oil market conditions has little impact on this outlook as can be observed in Figure 37. The only observable impact is in the EIA reference scenario with a 2000-60 emission target where the more reserved uptake of plug-in hybrid electric vehicles has taken some pressure off the demand for electricity relative to the other scenarios during the period from 2035.

Figure 37: Projected wholesale electricity prices across the core scenarios



In contrast to wholesale electricity prices, not surprisingly the cost of transport is much more sensitive to the variation in internal oil market conditions across the core scenarios. In the scenarios where oil supply is declining, both passenger and freight transport users begin investing immediately in non-oil fuel product based vehicles which increases the cost of transport. This is more evident for freight transport. Freight transport has the greatest incentive to shift away from oil-based transport vehicles since fuel is a greater share of total transport costs.

The lowest cost of transport outcomes are typically associated with the less challenging emission target, 2000-60, and EIA reference oil price. However, not always. It appears that in the case of freight transport the early investment in non-oil based road transport associated with declining oil scenarios, delivers lower cost of transport in the long term (i.e. lower than in the 2000-60, EIA reference oil price scenario). However, the total cost of freight road transport over the entire projection period is likely to be higher from a discounted cash flow basis which places greater weight on near term costs.

Regardless of the scenario the long term trend in the cost of transport is a declining one. Therefore, given income would be expected to double over the same period, households and business can still expect transport to be a smaller portion of the budgets in 2050 than they are today –albeit after a potential one to two decades of rising costs in the event of declining international oil supplies.

Figure 38: Weighted cost of road passenger transport in the core scenarios

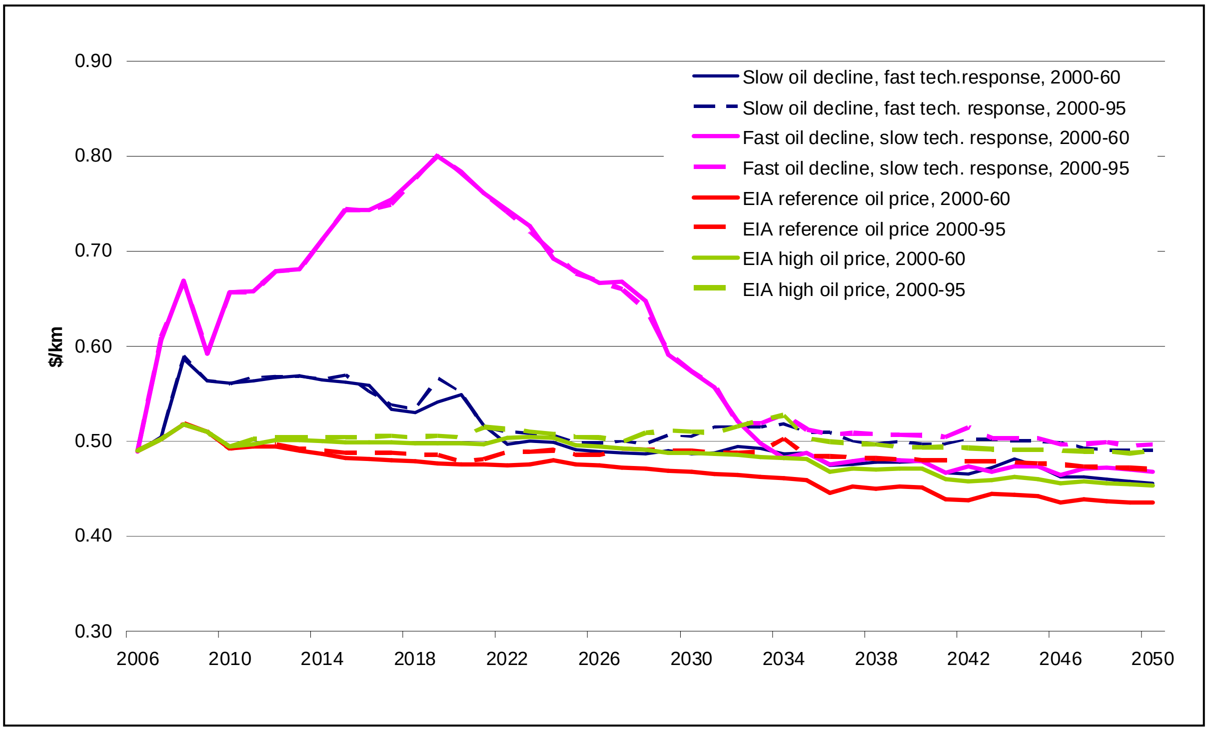
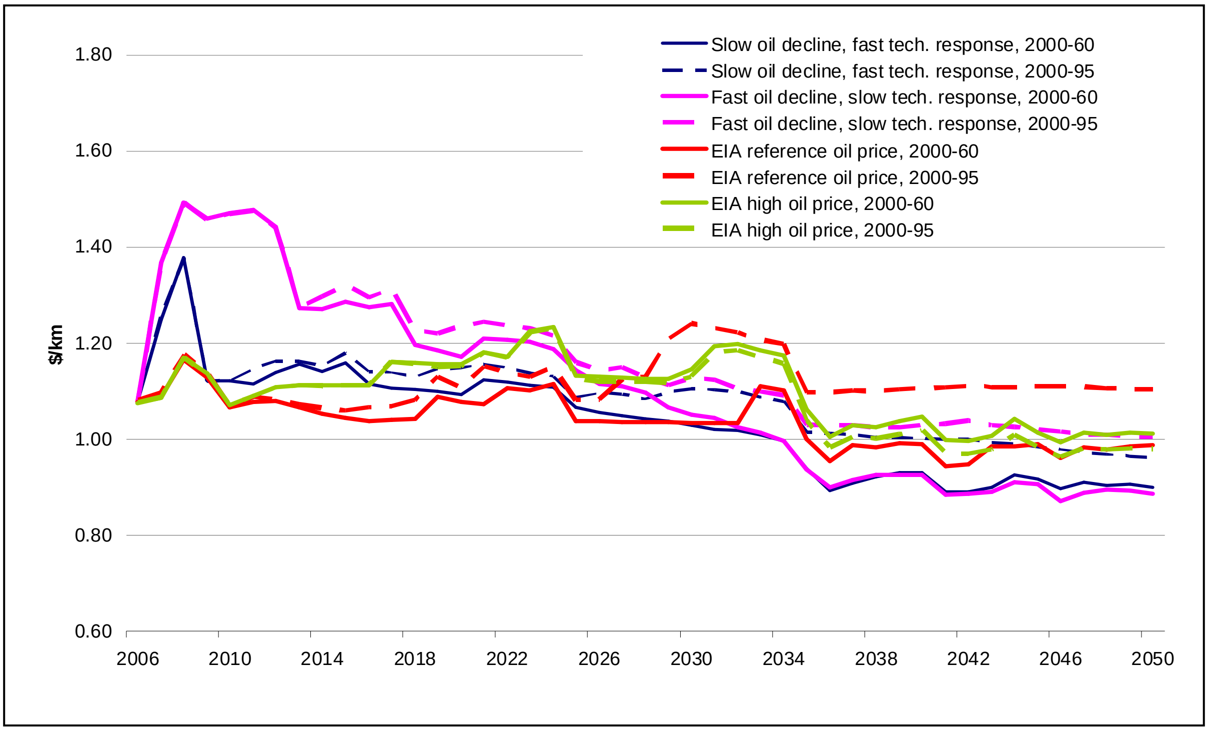


Figure 39: Weighted cost of truck (freight) road transport in the core scenarios



Land-use and crop production impacts

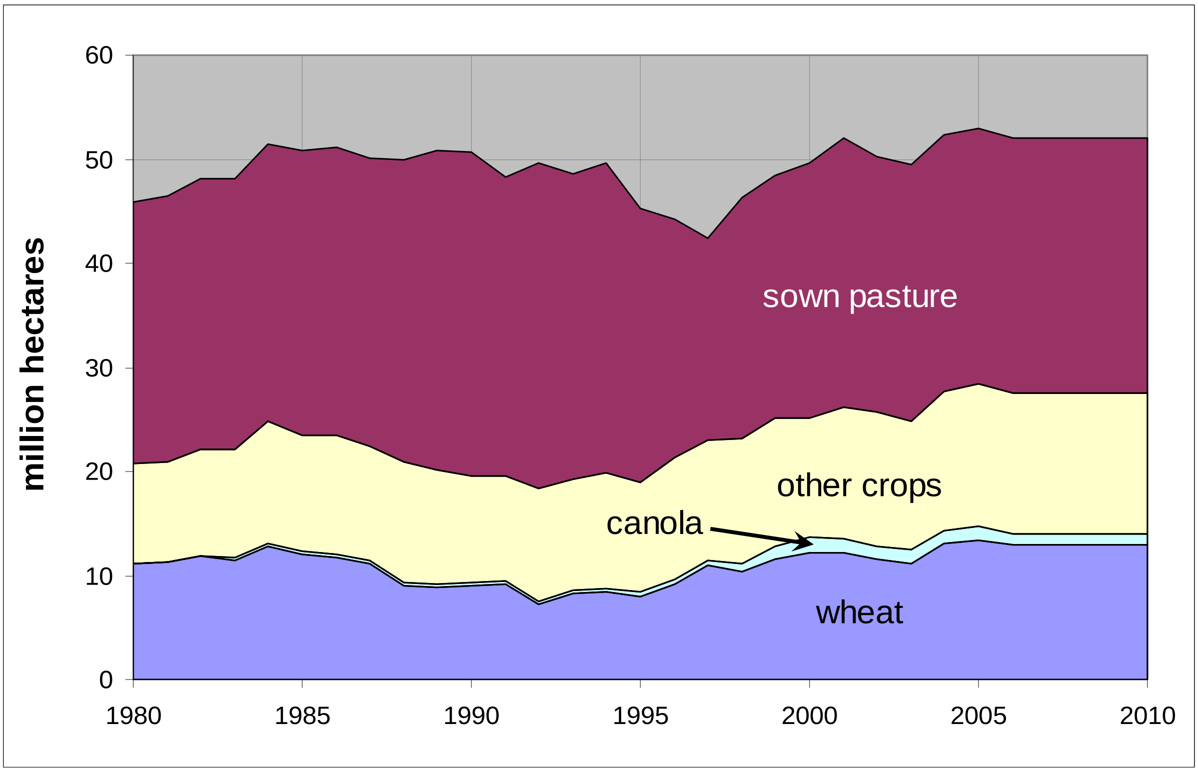
Biofuels can be produced using a number of different technologies based on the use of different feedstocks. As shown in Appendix A, ESM uses a simplified step function to represent the volumes of increasingly costly stocks of agricultural output that may be supplied as ethanol and biodiesel to the transport fuel market. This step function is modified between 2015 and 2020 to account for an expected shift in feedstocks toward lignocellulose in the case of ethanol and algae in the case of biodiesel. In the core scenarios, the model selects lignocellulose based ethanol but does not take up the algae based biodiesel because it is still assumed to be high cost (this assumption is relaxed in the algae sensitivity case below).

In this section (for ethanol), and later, in the sensitivity analysis (for biodiesel), we illustrate the scale of the impact of the uptake of biofuels on agricultural land use and traded agricultural commodities. For each biofuel, the significance of the anticipated shift from 1st to 2nd generation technologies (and the associated change in feedstocks) is highlighted. The illustrations involve the use of a more detailed representation of the production of biofuels and, more importantly, the production of the related feedstocks, than is currently available in ESM.

A large number of agricultural scenarios can be envisaged that would provide the feedstocks required for biofuel production. For this exercise, and in order to illustrate the scale of biofuel requirements against a known background, it is assumed that changes to business-as-usual agricultural production are kept to a minimum. The total area of cropland under cultivation is held constant, and changes to the areas devoted to particular crops to accommodate biofuel feedstock production are proportional to current areas devoted to those crops.

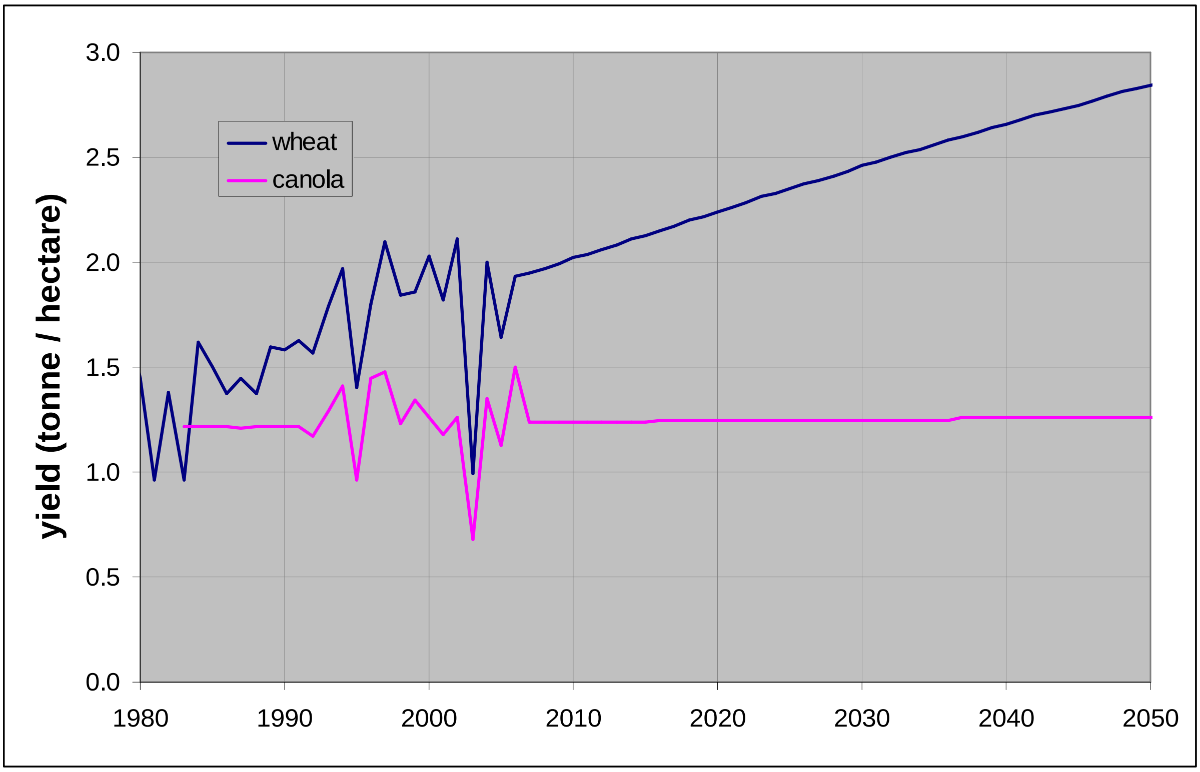
Figure 40 shows historical crop land use. In the absence of well defined trends and except where noted below, it is assumed that the land areas devoted to wheat (13 Mha) and canola (0.96 Mha) remain constant.

Figure 40: Historical crop land use in Australia



Some yields, however, have been rising. Figure 41 shows the assumed continuing increase in wheat yield. The canola yield shows no clear trend and is assumed to remain almost constant.

Figure 41: Historical and projected wheat and canola yields.



The differences in biofuel uptake between the core scenarios are fairly minor. The only exception is the case where there is a fast decline in oil supply and slow technology response because in this scenario there is a general shift away from petrol engines and towards synthetic diesel, electricity and gaseous fuels. Given the similarity of the model results, the case of ethanol is illustrated here using the high oil price with 2000-60 emission target core scenario. The case of biodiesel is illustrated in the "low cost biodiesel from algae" sensitivity case.

Two technologies for ethanol production are considered. Currently available 1st generation technologies use grains or sugars and compete for these feedstocks with existing demands (domestic food, feed, etc and exports). 2nd generation technologies are based on cellulose feedstocks for which there is currently no (or little) other demand. They may also have better overall net energy performance. However, they are still under development and are not yet commercially available. In the scenarios, it is assumed that 2nd generation technologies will be available by 2020. However, in the following, the difference between the technologies is illustrated.

For illustrative purposes, 1st generation ethanol feedstock is assumed to be wheat grain. In reality, at current small volumes Australia mostly uses cheaper by products such c-molasses or waste starch from flour milling. 2nd generation cellulosic feedstock is assumed to be wheat crop residues. Again, in practice, other feedstocks such as bagasse and timber waste may also be considered. Feedstock requirements are assumed to be:

- 1st generation: 114,618 tonne (wheat grain) / PJ (ethanol)
- 2nd generation: 130,489 tonne (wheat crop residue) / PJ (ethanol)

Yield data are obtained by dividing the quantities of product (grain, in the case of wheat) by the areas from which they were harvested, and are available because time series of these economically important data are recorded. The corresponding data for crop residues are not systematically recorded and need to be estimated.

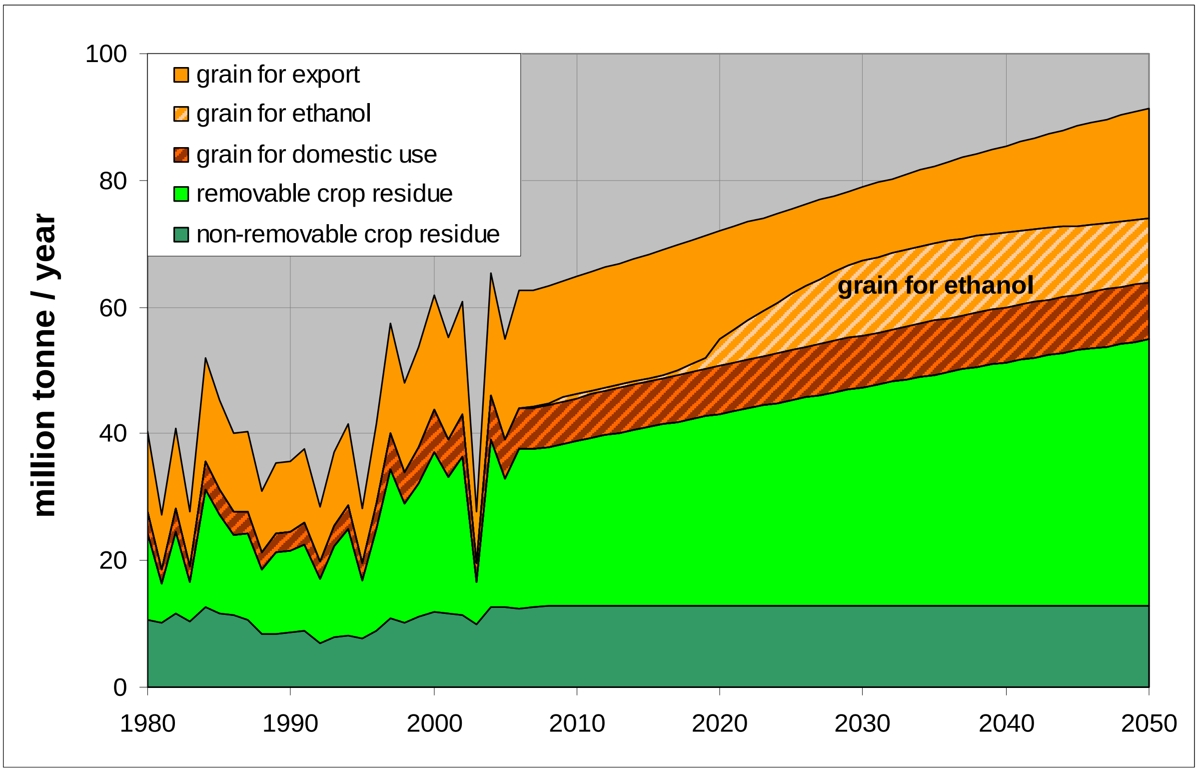
Agronomists estimate crop production characteristics using harvest indices which describe the partition of biomass to different parts of the plant. Harvest index is defined as the ratio of product (grain) to total above ground biomass. A typical figure for wheat is 0.4, and this is the assumption for this exercise. Crop residues are therefore calculated to be 1.5 (= (1.0 - 0.4)/0.4) times the grain produced. However, not all crop residues can be removed, and it is assumed that a minimum of 1 tonne/hectare is left on the land for soil protection purposes.

Figures 42 and 43 show total above ground biomass produced on land area devoted to wheat production. Dark and light brown shades represent wheat grain harvested for domestic consumption or export. Dark and light green shades represent the remaining above ground biomass that becomes crop residues and is not currently used.

Figure 42 shows the quantity of wheat grain required as ethanol feedstock using 1st generation technology as a deduction from the quantity that would otherwise be available for export.

Figure 43 shows the quantity of wheat crop residues required as ethanol feedstock using 2nd generation technology. In this case the feedstock is deducted from removable crop residues that would not otherwise be used.

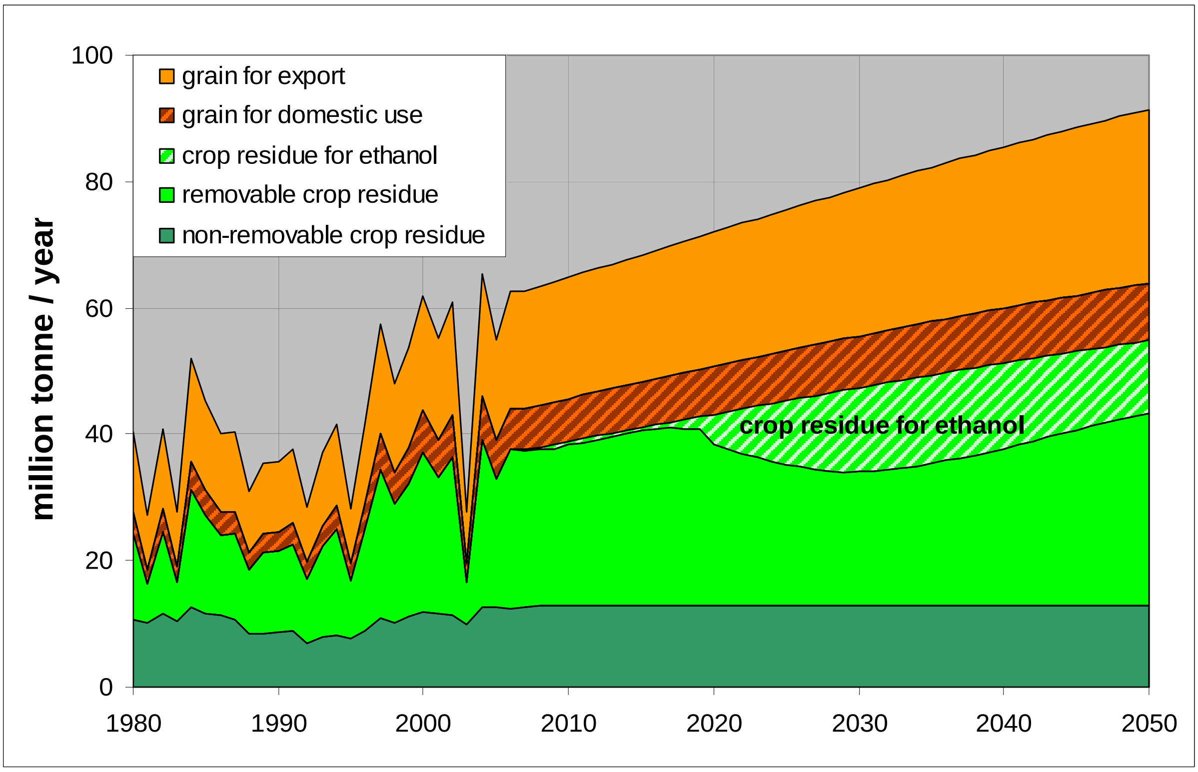
Figure 42: Illustration of the impact on wheat exports and consumption and quantity of wheat grain required if only wheat grain and 1st generation ethanol production technology is available for the projected ethanol use in the high oil price, 2000-60 emission target scenario



Demand for ethanol in the this scenario peaks in 2035 at 107 PJ/yr at which point it represents 13% of road transport energy requirements. This relatively small demand share should be borne in mind in assessing the impact of feedstock production. If the demand is met by 1st generation technology using wheat grain, it would require 50% of wheat exports in the peak year. Although the economic consequences of this diversion have not been explicitly modelled, it could not fail to have a substantial impact on wheat prices and, via feedback, on the price of the ethanol fuels themselves.

On the other hand, if 2nd generation technology using wheat crop residues can be developed, there would be no impact on wheat exports or on any other demand for wheat grain. In the peak year, 38% of the removable wheat crop residue would be required. While further work is required on the sustainability impacts of removing crop residues and, in particular, on the quantity that needs to be left on the land (here assumed to be 1 tonne per hectare), 2nd generation technology clearly makes a proportionately much smaller demand on the resource base. Not only does this cellulose resource also include the residues from other crops, but there is potentially a much larger component of forestry materials yet to be estimated.

Figure 43: Illustration of the impact on wheat exports and consumption and the quantity of wheat crop residue required if 2nd generation ethanol production technology is available for the projected ethanol use in the high oil price, 2000-60 emission target scenario



Sensitivity cases – social and cultural preferences for transport

The core scenarios included steady to rising or radically rising oil prices and moderate to deep greenhouse gas emission targets implemented via emission trading. It was felt that under these scenarios it was appropriate to expect some significant change in social and cultural preferences toward lighter vehicles, greater use of public transport and overall reduced travel and freight movements.

In order to understand and impact of those assumptions and to see the alternative outcome if Australia's social and cultural preferences do not change, this case explores what the modelling would have found if those preferences were left unchanged from the present day.

The EIA high oil price scenario with the 2000-60 emission target is used to illustrate the impact of this change in assumptions. Figure 74 shows the outcome for this sensitivity case in terms of kilometres travelled by mode and vehicle category. Light, medium and heavy passenger vehicles maintain a fairly even mix and the heavy and medium categories dominate the light commercial vehicle category. Bus transport remain minor. Noting the change in scale, total kilometres travelled is around 100 billion kilometres greater than in the core scenarios.

Figure 75 shows the fuel consumption levels and fuel shares. It can be seen that the higher level of private passenger travel has not significantly affected the fuel choice but fuel consumption exhibits a rising trend for much of the projection period, only seeing a decline from 2030 when cost competitive hybrid electricity vehicles become available.

As a consequence of the higher fuel consumption the transport sector achieves less greenhouse gas abatement in this sensitivity case than in the core scenarios. By 2050 emissions are around 10MtCO_2e higher than the equivalent core scenario (Figure 46). The gap is higher if EIA reference oil prices prevail. The gap is narrowed if the 2000-95 emission target is in force.

Figure 44: Kilometres travelled by mode and road vehicle type: Social and cultural preferences unchanged, EIA high price and 2000-60 emission target

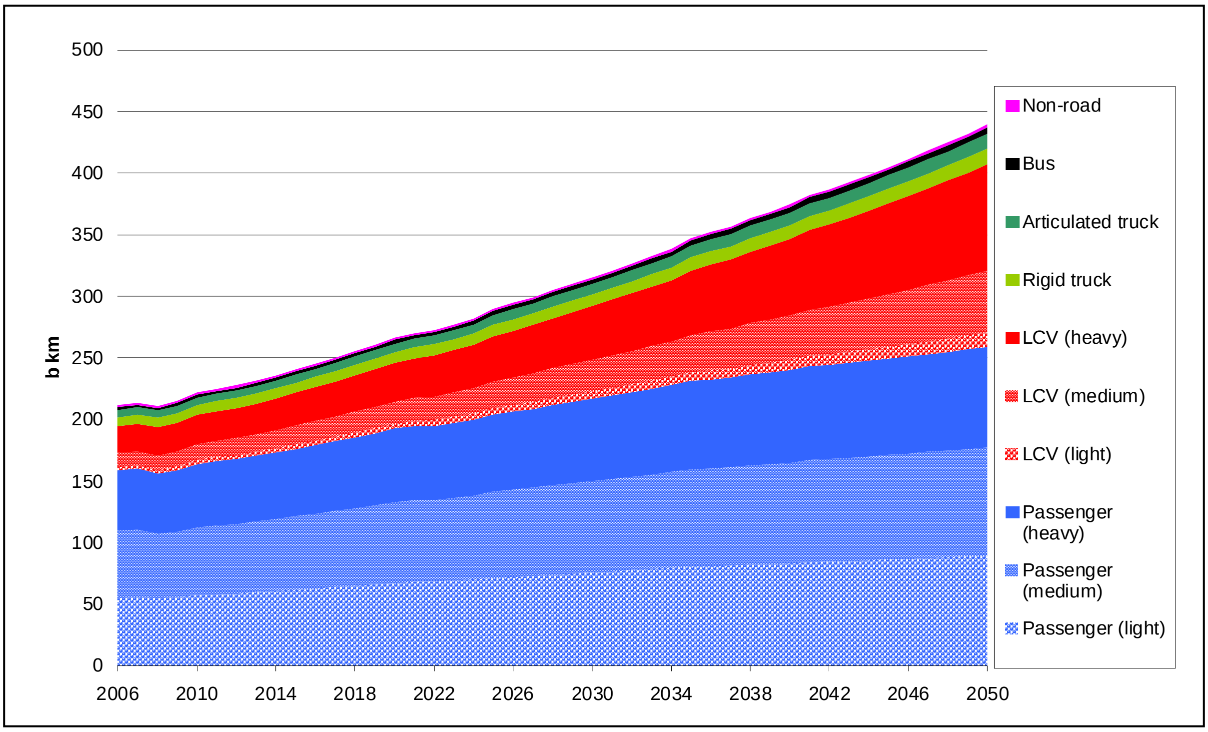


Figure 45: Transport sector fuel consumption: Social and cultural preferences unchanged, EIA high price and 2000-60 emission target

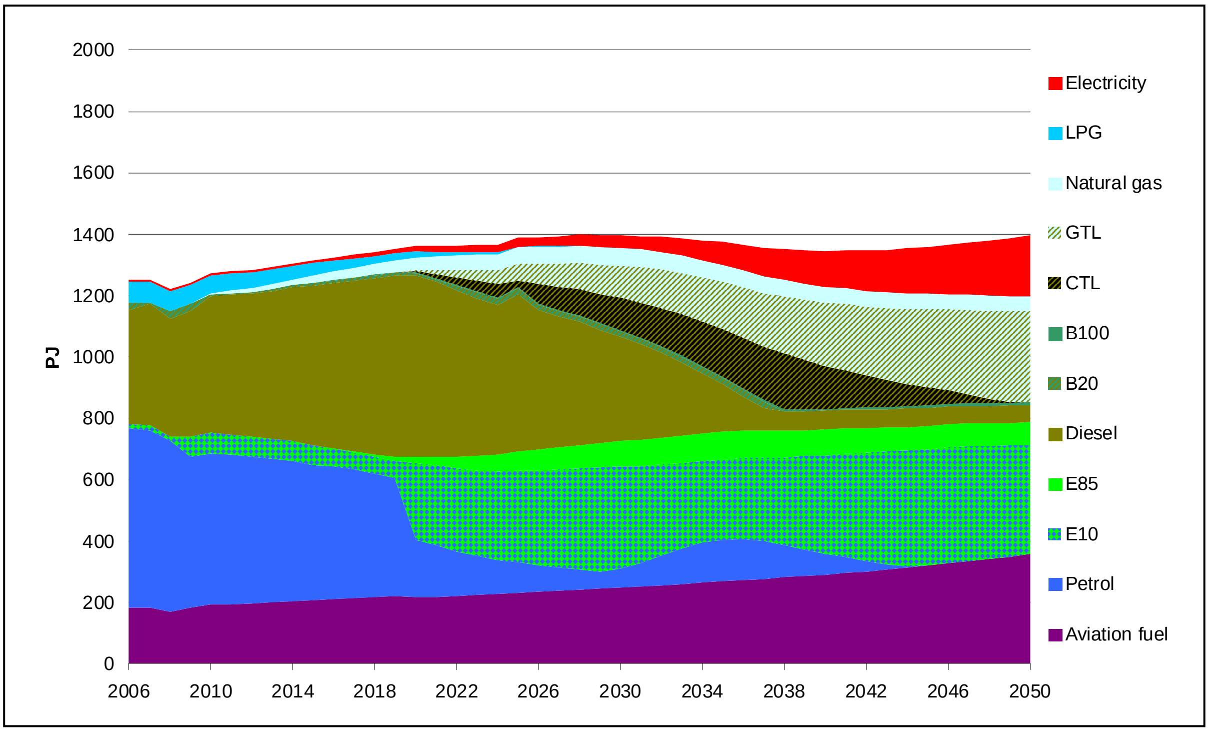
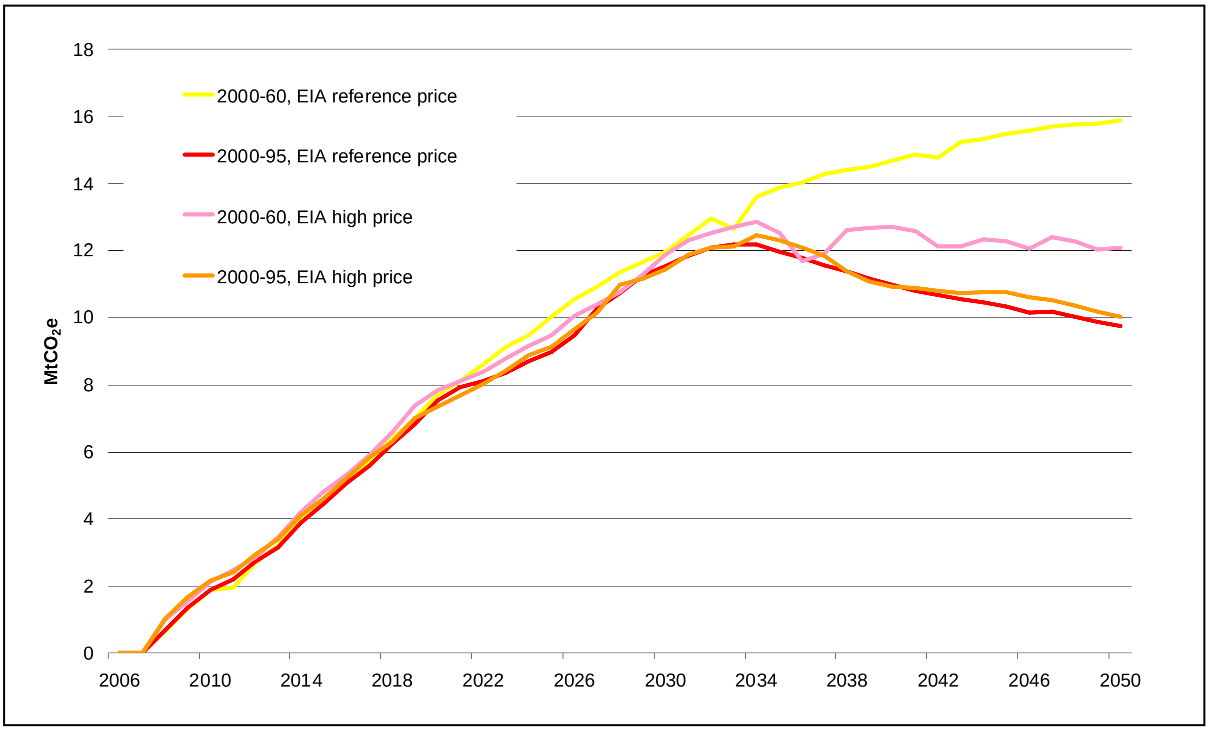


Figure 46: Changes in transport sector greenhouse gas emissions under the social and cultural preferences unchanged sensitivity case relative to the core scenarios



Sensitivity cases – additional government policies

The Future Fuels Forum discussed a variety of additional government policies that may be implemented to complement an emission trading scheme or achieve other goals. The following four polices were selected for modelling on the basis that they represent a mix of "carrot and stick" approaches, are amenable to quantitative modelling and have previously been discussed by government and non-government groups. These polices are modelled for the purposes of exploring their impacts so that governments may be more informed about their potential outcomes.

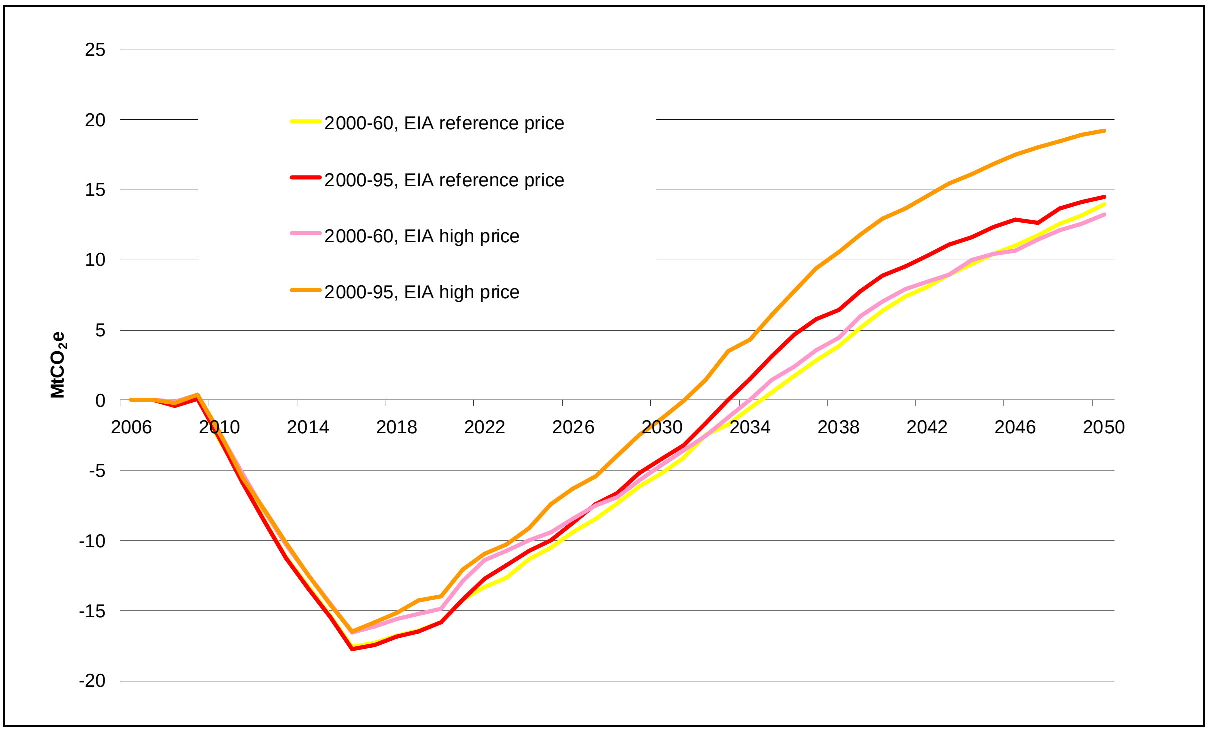
Accelerated vehicle scrapping

Accelerated vehicle scrapping has long been advocated as a possible measure to improve the fuel efficiency and reduce emissions from the Australian road vehicle fleet. The enthusiasm for such polices is partly due to the observation that Australia has a relatively older vehicle fleet with an average age of 12 years.

The policy case that is implemented assumes that, beginning from 2010 a compulsory scrapping regulation is brought in nationally such that vehicles 20 years or older cannot be registered to travel on Australian public roads. This would effectively mean vehicles not meeting the age limit would be permanently stored or sold for scrap. In 2011 the compulsory scrapping age increases to 19 years. The legislation continues until it is fully phased in at 2014 and compulsory scrapping of 15 year age vehicles or older. The legislation applies equally to all road vehicle types including trucks.

Note that reducing the life of a vehicle increases the share of the emissions embodied upstream in the manufacture of the vehicle. However, these upstream vehicle manufacture emissions are small (around 10-30 percent) relative to the emissions released during the life of the vehicle. Therefore, so long as the 15 year old vehicle is replaced with another vehicle that is more fuel efficient then it will more than offset the extra emissions from additional vehicles being manufactured. Note that under international emission accounting conventions, emissions created during the manufacture of a vehicle in another country are not counted in Australia emission if the vehicle is imported. Nevertheless, if that country is acting to reduce emissions it may pass on the additional cost of emission compliance in the vehicle cost. No special assumptions have been made in this regard since it is uncertain which countries will take part in a global emission trading scheme.

Figure 47: Change in transport sector greenhouse gas emissions under the accelerated vehicle scrapping policy sensitivity case relative to the core scenarios



Ignoring emission from manufacturing vehicles, Figure 47 shows the emissions saved in the short term from having a greater portion of newer more fuel efficient vehicles in the vehicles stock. The period up to 2015 clearly shows a rapid decline in transport sector emissions due to the increased scrapping of older vehicles and consequent rapid decline in the average age of vehicles.

After the phase in period, 15 year old vehicles continue to be scrapped. However transport sector greenhouse gas emissions begin to rise or in the best case (where the 2000-95 emission target is in place) decline at a slower rate than if the policy were not in place. This indicates a so called “rebound effect” may be occurring where consumers who are made more resilient to rising prices moderate their response to them in the future. In this case, the scrapping of older vehicles early on in the projection period has meant that consumers need higher fuel and carbon prices, relative to the case where the policy was not in place, to justify switching to a lower emission or higher fuel efficiency fuel and vehicle combination.

The result of this rebound effect is that post-2015 technology uptake is delayed and as a result emission levels are higher by 2050 relative to the core scenario where the accelerated scrapping policy was not in place.

Higher fuel excise

An additional tax that directly target fuel use would be expected to lead to greater incentives to take up more fuel efficient vehicles and subsequently reduce greenhouse gas emissions in the transport sector. This sensitivity case was explored in order to determine how much of a difference high fuel excise would make to transport greenhouse gas emissions.

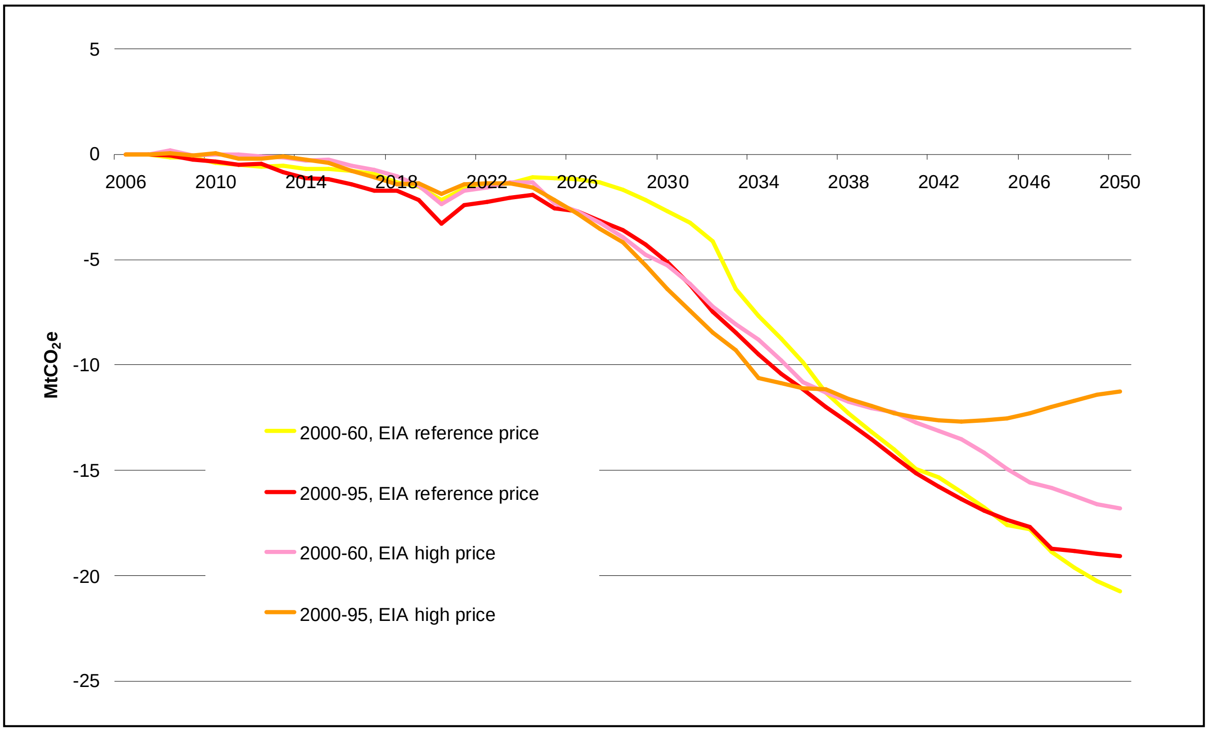
Current fuel excise for most petrol and diesel vehicles is 38c/L with several exemptions for various diesel commercial and public transport applications. Alternative fuels are taxed at lower rates approximately proportional to their lower energy content.

This sensitivity case models the outcome if fuel excise were increased from current levels by five percent per annum to approximately 210c/L in real terms by 2050. Holding all else constant this would be equivalent to arriving a retail petrol price of around $3.00/L (real).

Figure 48 Shows the emission reduction achieved for the core scenarios with and without the higher fuel excise rate. It indicates that a policy of higher fuel excise would be effective in reducing emission in the transport sector over and above the impact of the prevailing CO_2e permit price. This result is no surprise. The fuel excise rate that was applied in the scenario is equivalent, by 2050, to a $1000/t$CO_2e$ permit price which is around 16 times the CO_2e permit price imposed by the 2000-60 emission target.

This additional price incentive drives greater uptake of hybrid and fully electric vehicles, greater use of biodiesel and LPG and reduces overall transport demand.

Figure 48: Change in transport sector greenhouse gas emissions under higher fuel excise sensitivity case relative to the core scenarios



Low emission vehicle subsidies

The previous two policy sensitivity cases impose additional costs on consumers to provide additional incentive to shift to more environmentally sustainable transport fuels. An alternative policy approach that government may consider introducing is to provide cash incentives for businesses and consumers to purchase lower emission vehicles.

In modelling this sensitivity case, it is assumed that consumers are given $2000 (in real terms) on the condition that it be put toward the purchase of any deemed low emission vehicle. In the model this includes, hybrid electrics, full electrics, LPG, natural gas vehicles, high blend capable biodiesel, ethanol and hydrogen vehicles. In reality government might seek to tighten the choices consumer make or offer a sliding scale based on relative emission intensity. The subsidy remain in place through the projection period.

Under these assumption the model projects that vehicle purchaser will primarily choose to put the subsidy towards mild hybrid electric vehicles. The effect of the subsidy is to bring forward the widespread uptake of mild hybrid electric vehicles by around a decade.

Figure 50 shows that the low emission vehicle subsidy is effective in reducing emissions by an average 3 million tonnes each year for the first 20 to 30 years of the scheme. However, in the last two decades of the projection period a rebound effect begins to emerge whereby transport sector emissions are higher with the policy in place. As was observed in the accelerated vehicle scrapping sensitivity case, an unintended consequence of making consumers more resilient to carbon prices is that their incentive to make further investments in reducing carbon price exposure is reduced.

Figure 49: Share of different engine types in road kilometres travelled: EIA high oil price, 2000-60, low emission vehicle subsidy sensitivity case

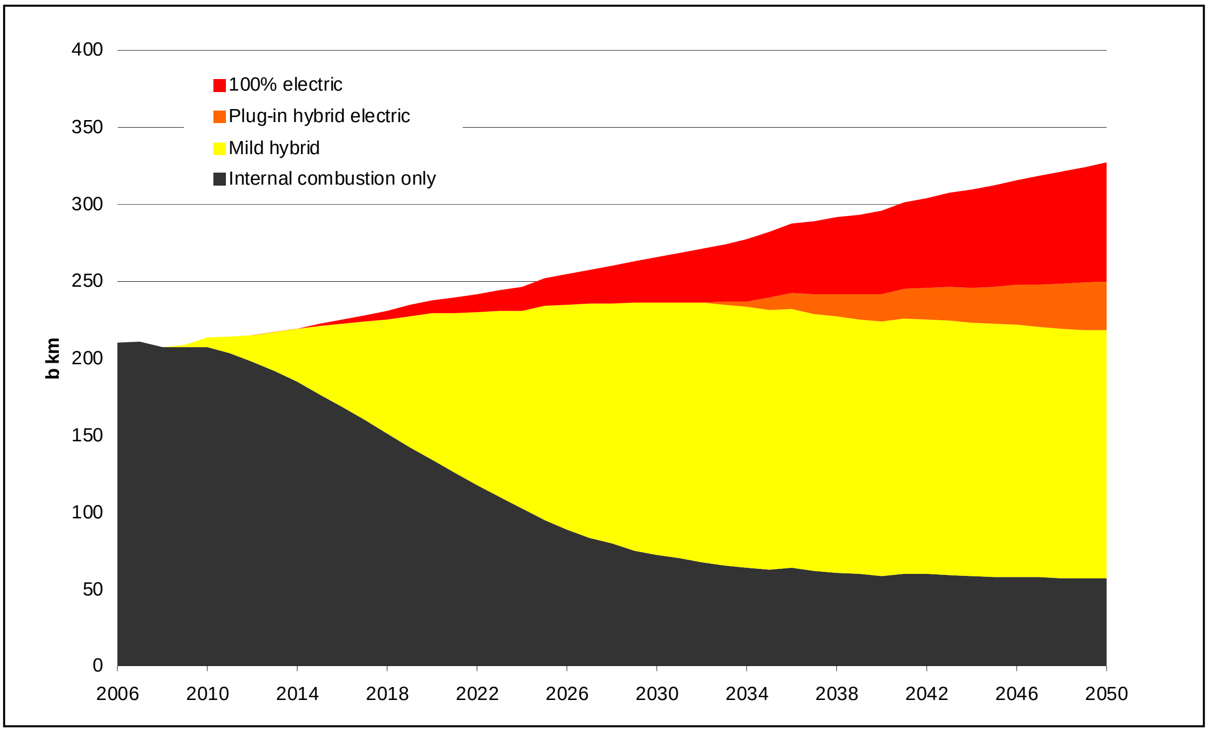
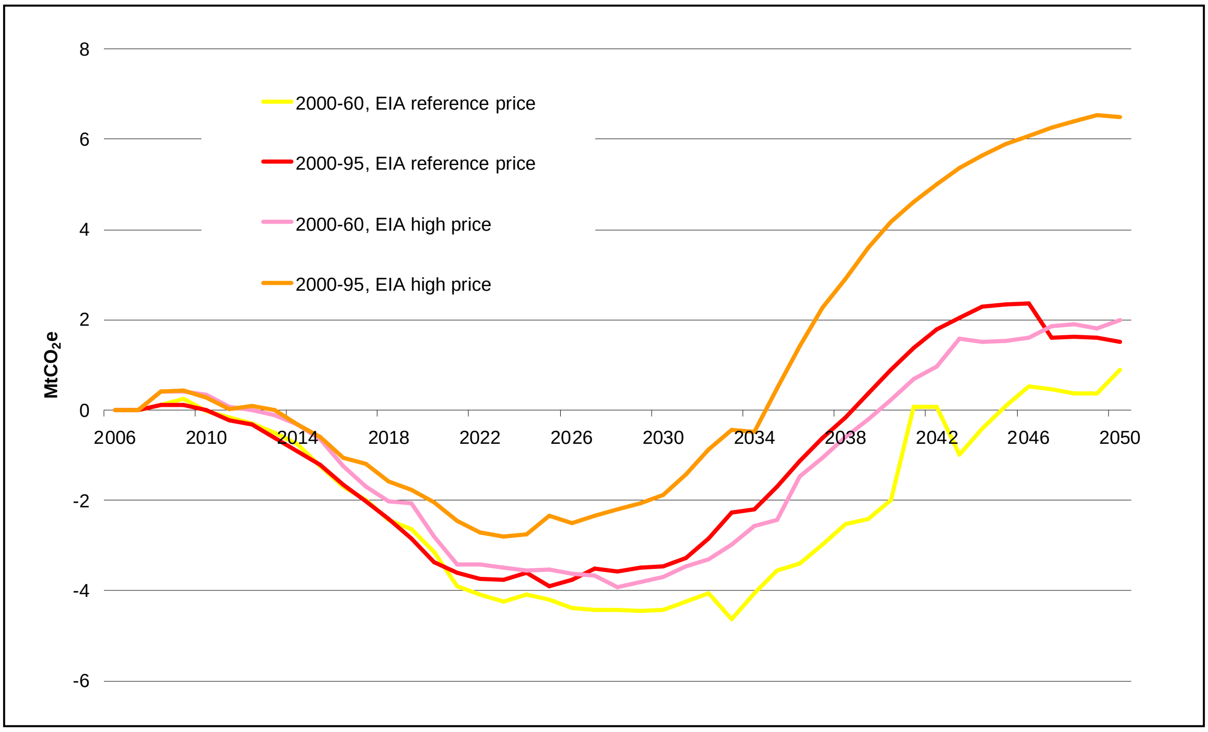


Figure 50: Change in transport sector greenhouse gas emissions under a low emission vehicle subsidy sensitivity case relative to the core scenarios



Mandatory fuel efficiency standards

Energy efficiency is only one of several features consumers consider when purchasing a product. When the cost of energy is low, it is possible that consumers will fail to make high energy efficiency an important priority in their purchasing decision. This is arguably the case in the light vehicle market where the fuel cost is only 20 percent of total travel costs. In light of these concerns governments may use their ability to enforce minimum standards of energy efficiency on vehicles sold.

This sensitivity case explores the scenario where governments phase in a mandatory fuel efficiency standard such that it results in a one third average road vehicle fleet fuel efficiency improvement relative to the energy efficiency improvements that were projected to take place without the policy in place (see Appendix A). It is assumed that the fuel efficiency improvements are delivered at no extra cost to the consumer.

The one third improvement rate is applied to all road vehicle categories. In reality governments might allow vehicle retailers to meet such a target by selling a greater proportion of lighter vehicles or apply different rates to different vehicle categories. The purpose of the sensitivity case is to determine what additional impact the policy would have relative to the core scenarios.

The modelling results show that the introduction of mandatory fuel efficiency standards reduces the incentive to take up alternative fuel and engine technology over the long term. In the IEA high oil price 2000-60 scenario the level of plug-in electricity vehicle uptake is greatly reduced relative to the case where the policy is not in place (Figure 51). Figure 52, which shows transport sector fuel consumption for the EIA reference oil price 2000-95 scenario, shows the effect of the mandatory fuel efficiency standards policy even more dramatically. In this sensitivity case the model projects a much reduced change in the fuel mix relative to today with much more subdued rates of uptake of natural gas, electricity and coal to liquids diesel compared to the case where the policy is not in place.

Figure 51: Share of different engine types in road kilometres travelled: EIA high oil price, 2000-60, mandatory fuel efficiency standards sensitivity case

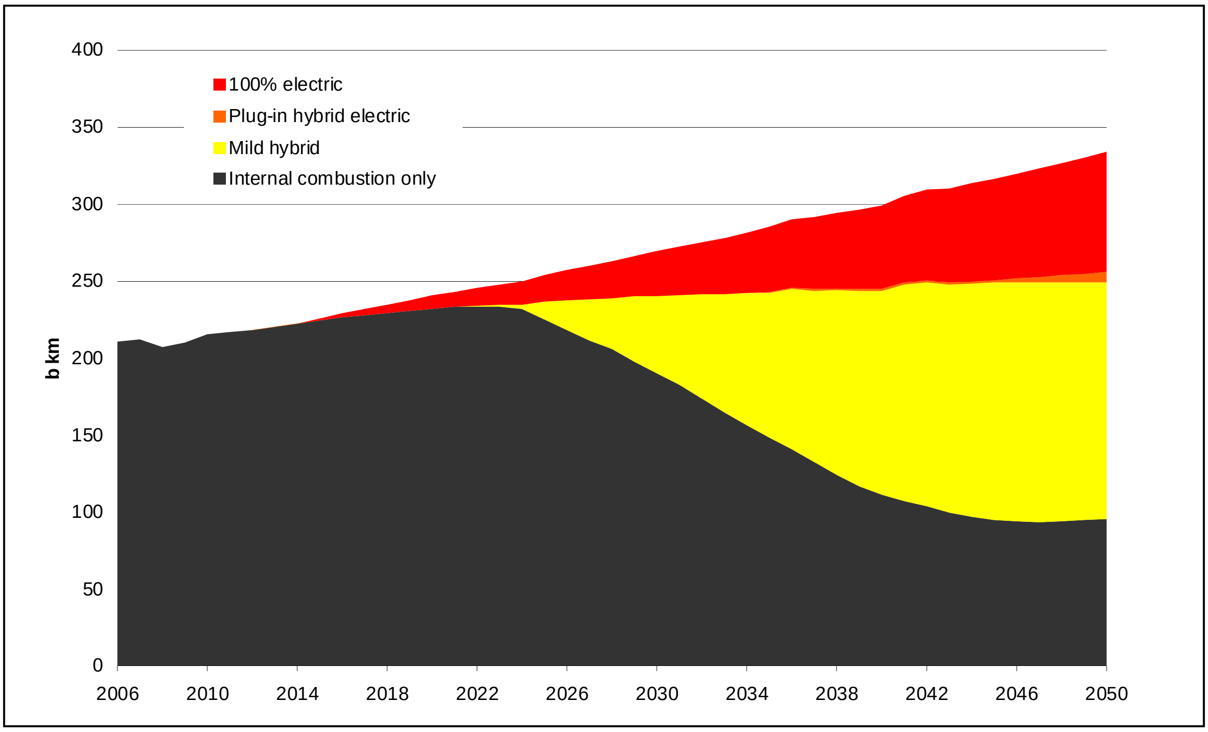
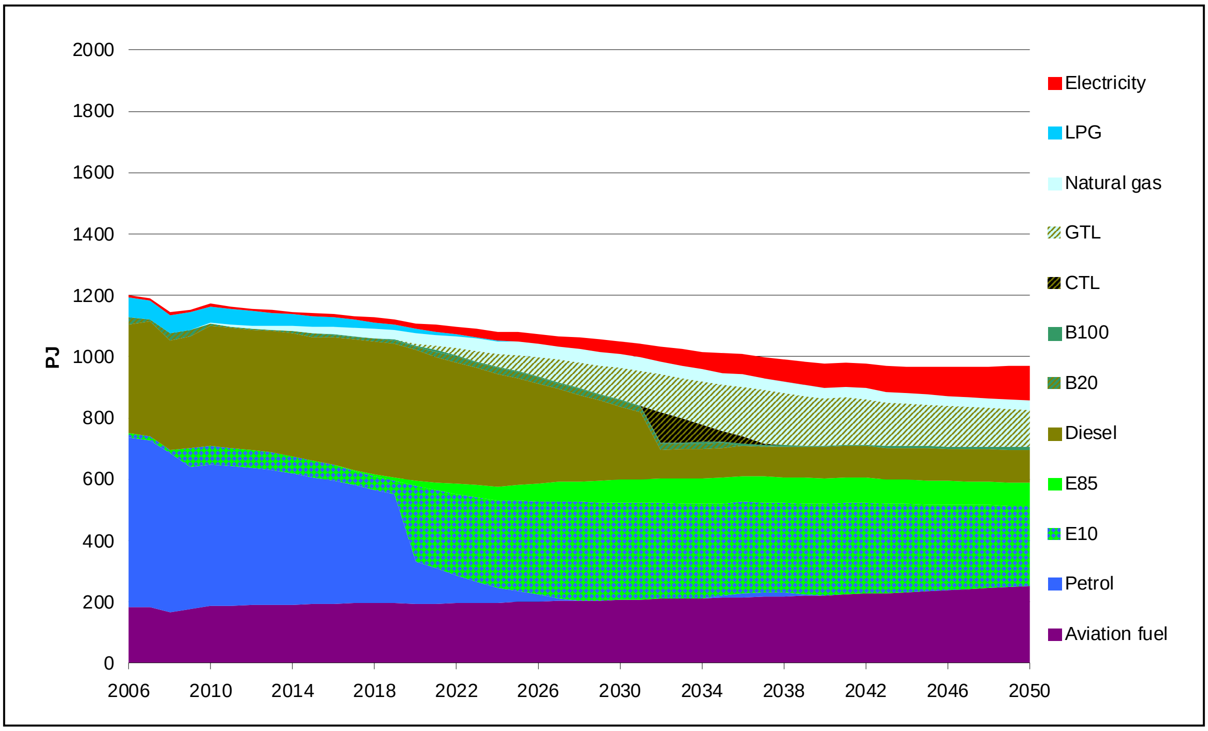
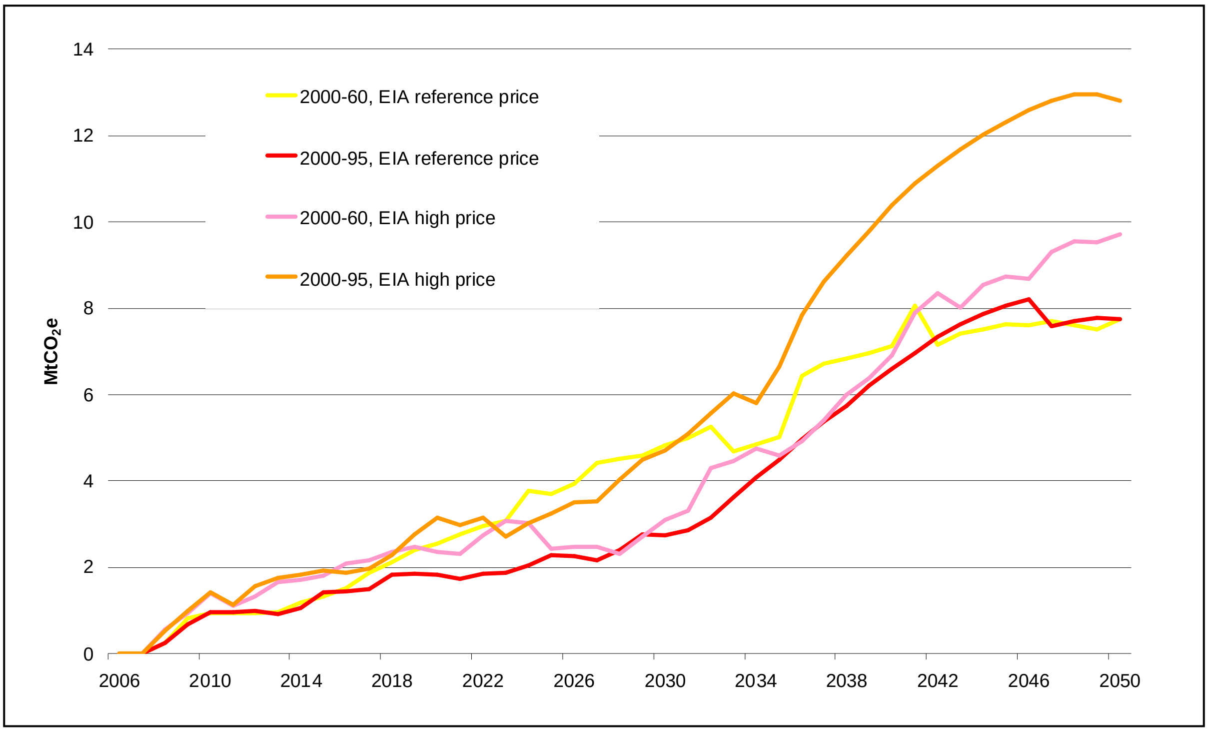


Figure 52: Transport sector fuel consumption: EIA reference price, 2000-60 emission target and mandatory fuel efficiency standards sensitivity case



Almost from the very start of the projection period the policy leads to an immediate rebound effect whereby the reduced fuel costs from access to more efficient vehicles leads to greater demand for transport and less incentive to invest in more fuel efficient vehicles. As a consequence, transport sector greenhouse gas emissions are higher with than without the mandatory fuel efficiency standard policy (Figure 53). It may be possible to prevent this outcome by revisiting standards to ensure they keep pace with the most efficient technology (e.g. hybrid electric vehicles).

Figure 53: Change in transport sector greenhouse gas emissions under mandatory fuel efficiency standards sensitivity case relative to the core scenarios



Sensitivity cases – technology uncertainty

Hydrogen

Part of the reason for examining hydrogen as a sensitivity case is that in all of the other scenarios hydrogen is only dealt with as an internal combustion engine. All electric vehicles are assumed to be battery powered rather than hydrogen fuel cell powered. The reasons for this are explained in Appendix A and primarily relate to maintaining a manageable model size.

In this sensitivity case we replace the battery power electric vehicle which is available in the light vehicle category in ESM and replace it with a fuel cell vehicle. While fuel cell vehicles have long been a "concept car" they are now available in the United States as a commercial vehicle although with some restrictions. The Honda Clarity is available in California in the United States of America via a three year $US600 per month lease (http://automobiles.honda.com/fcx-clarity/).

The leasing arrangement is because of the lack of existing servicing and refuelling infrastructure. Longer term Honda is planning to deliver a home fuelling station that would produce hydrogen via electrolysis negating the need to visit a refuelling stations. The range of the vehicle is 435km holding

5kg at 5000psi in its 171 litre tank making home refuelling feasible for urban driving, more so if a household has a second vehicle for longer journeys or is prepared to hire one.

To construct a sensitivity case where hydrogen fuel cell road vehicles are taken up in Australia it is assumed that all of the hydrogen is produced from electricity at a conversion efficiency for the electrolysis process of 63 percent. Electricity was chosen since, as we have seen in other scenarios, electricity is a good candidate for being a low emission fuel source in the future. However, some further research should also investigate other primary energy resources such as biomass and natural gas.

The cost of fuel cell vehicles, inclusive of a home refuelling station, is assumed to be the same as the battery electric vehicles. This simple approach is justified on the basis that no better data could be found - the Honda vehicle lease price is not considered to be reflective of costs as it may either be too low, being an introductory price to encourage early adoption or too high as economies of scale in production would not have been reached at this stage of the product lifecycle.

The modelling results indicate hydrogen fuel cell vehicles could contribute to around 20 percent of road kilometres travelled but only add 10 percent to total direct fuel consumption (Figure 54 and Figure 55). In this manner they occupy a similar role to battery electric vehicles, both being able to take advantage of the more efficient electric drive train.

However, hydrogen fuel cell vehicles have the added advantage of having a long driving range (435km for the Honda Clarity compared to around 100km for current battery vehicles on market – but expected to improve). As a result the modelling results presented here may have under-estimated the potential market for such a vehicle which could make further in-roads into the medium and heavy passenger vehicle markets providing the fuel cell and electric engine can be incorporated cost effectively in such vehicles.

Figure 54: Transport sector fuel consumption: EIA high oil price, 2000-60 emission target and hydrogen sensitivity case

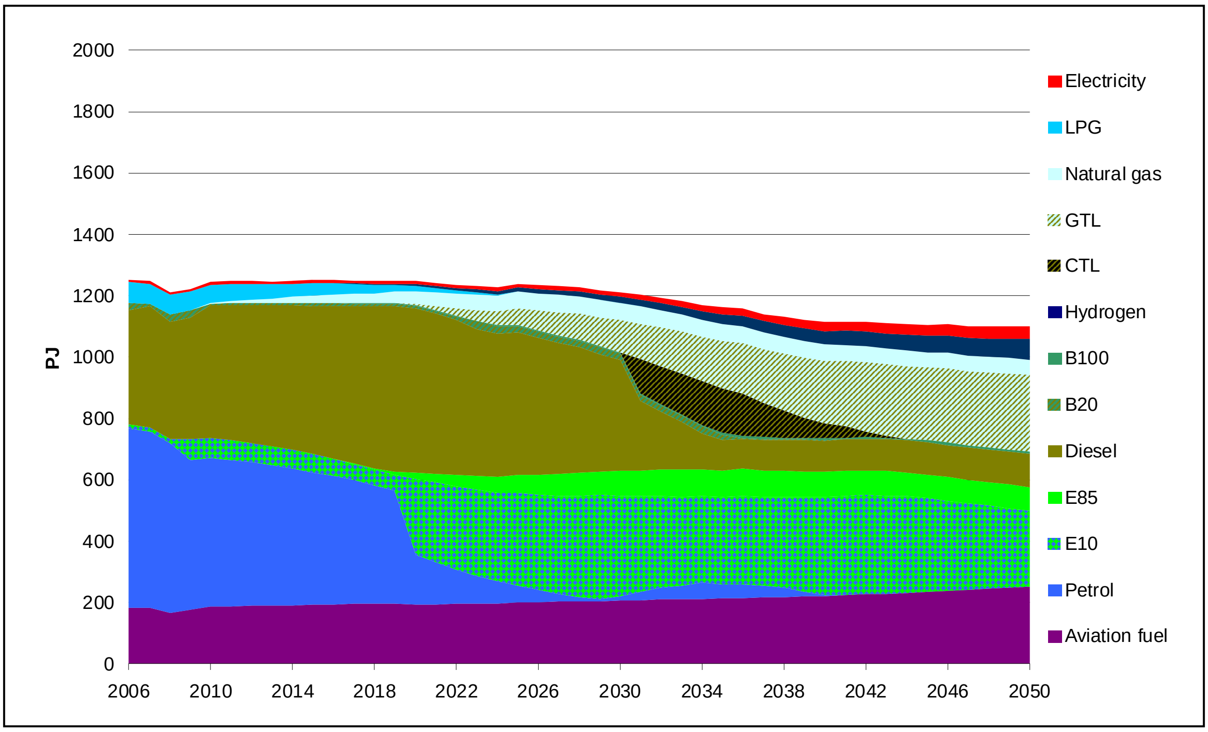
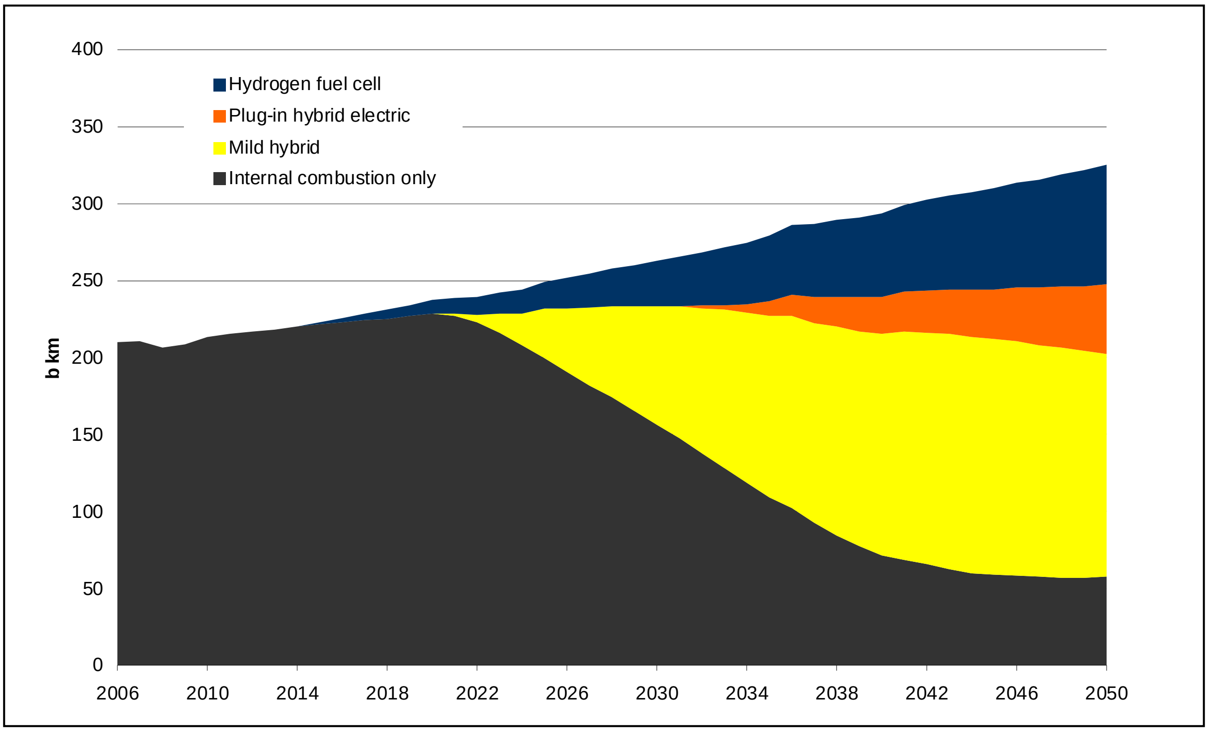


Figure 55: Share of different engine types in road kilometres travelled: EIA high oil price, 2000-60, hydrogen sensitivity case



Low cost biodiesel from algae

The exciting characteristic of biodiesel produced from algae is that it magnifies the amount of biodiesel that can be produced per land area by a factor of at least five relative to conventional biodiesel production from oil seeds and tallow. As a result, if biodiesel from algae can be produced cost effectively from algae then this greatly increases the role that biodiesel could potentially play in the transport fuel mix.

In the core scenarios, it was assumed that biodiesel from algae was available from 2015 but at around 40 percent higher than the cost of biodiesel from canola. In this sensitivity case we explore the scenario where biodiesel from algae is available at near the cost of oil-based diesel (around $20/MJ).

Under these assumptions the modelling projects that biodiesel from algae will be taken up in very large volumes and eventually dominate the diesel vehicle market. The fuel is initially taken up as a 20 percent blend with oil based diesel so that it can be used in the current vehicle stock. However, its use in higher blends is also favoured after sufficient time to build up the stock of vehicles capable of using a high blend biodiesel.

The availability of low cost biodiesel encourages greater use of diesel vehicles in general at the expense of the market share of petrol and natural gas. The use of higher efficiency diesel vehicles together with the low emission intensity of biodiesel from algae results in additional emission saving relative to the core EIA high oil price 2000-60 and 2000-95 scenarios of 10 and 8 $MtCO_2e$ respectively by 2050. Additional emission savings are 50 percent higher than this around 2025 but the gap narrows from this point onwards as electrical hybridisation reduces the relative importance of liquid fuels in determining emission outcomes.

Figure 56: Transport sector fuel consumption: EIA high oil price, 2000-60 emission target and low cost biodiesel from algae sensitivity case

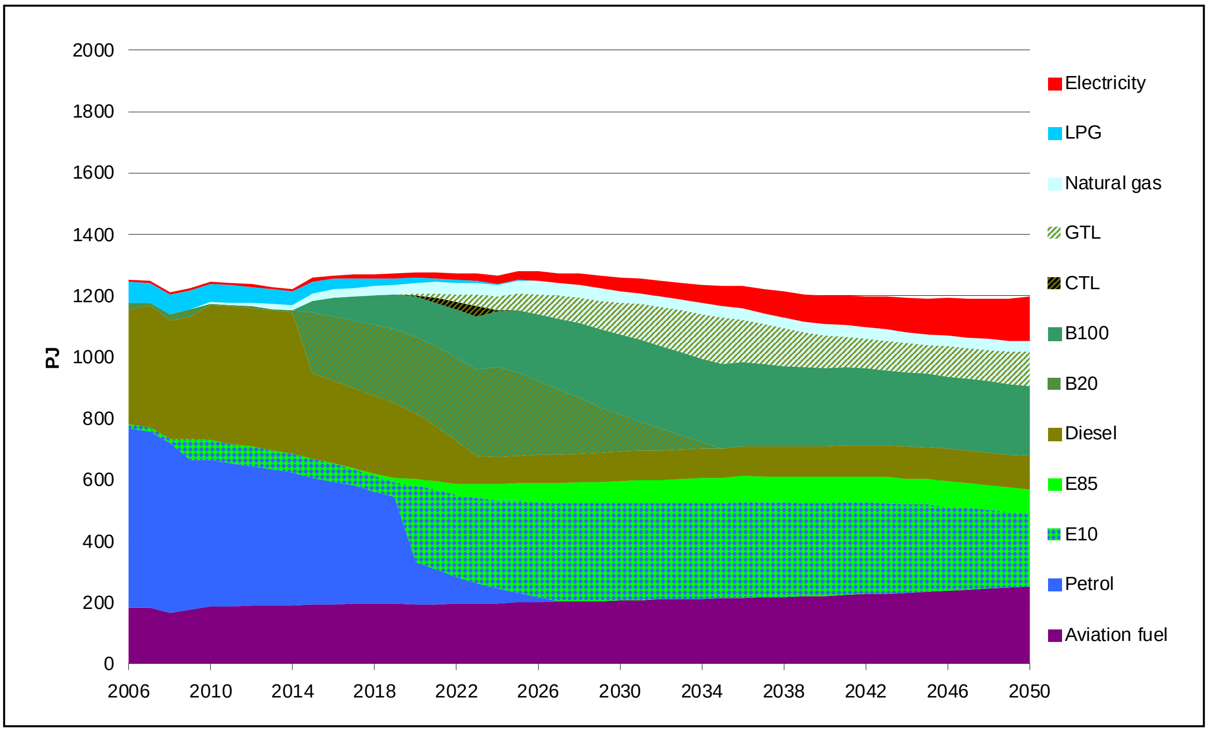
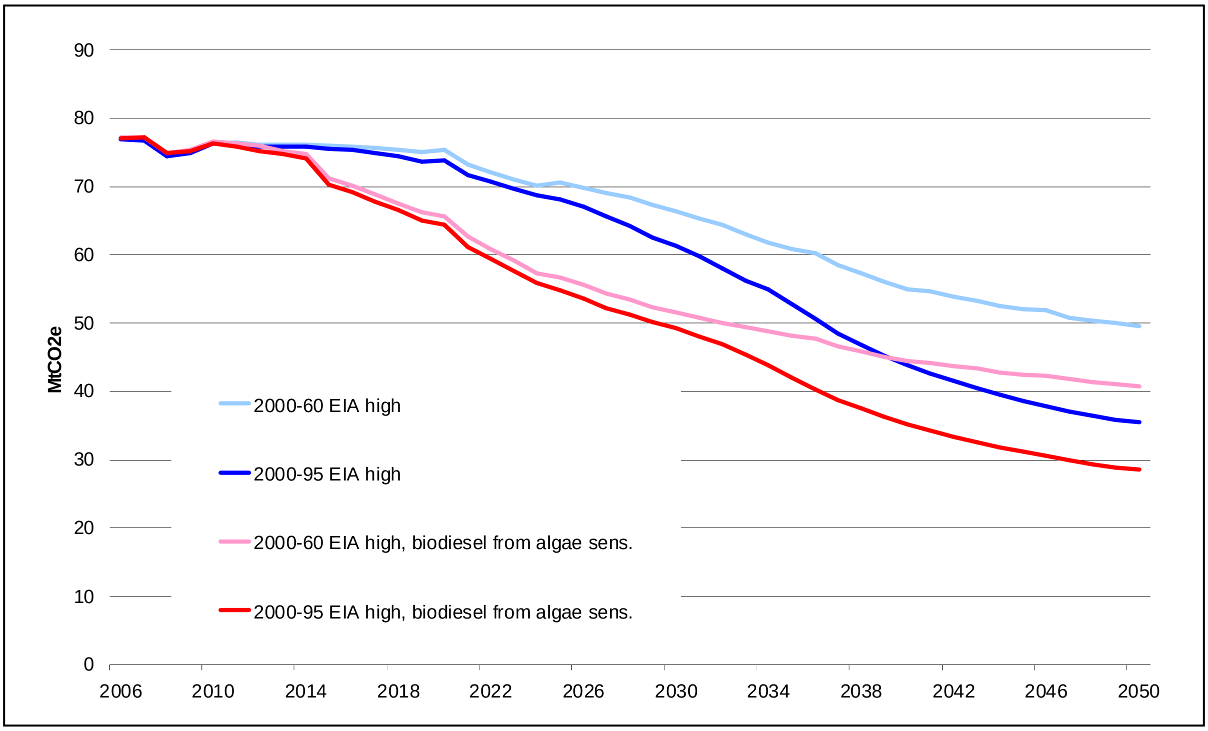


Figure 57: Transport sector greenhouse gas emissions: low cost biodiesel from algae sensitivity analysis



Implications for crop production and land use

As in the earlier discussion of ethanol, in this section we illustrate the impact of the uptake of biodiesel on land use and agricultural trade, emphasising the difference between 1st and 2nd generation technologies. Demand for biodiesel in this scenario peaks in 2037 at just over 30% of road transport energy requirements, and this should be borne in mind when assessing the impacts.

The 1st generation technology for the production of biodiesel is well established, obtaining the required vegetable oils or animal fats from such sources as oil seeds, used cooking oil or tallow. Here, for illustrative purposes it is assumed that canola seed is the sole source.

The 2nd generation technology for biodiesel production is expected to use oil derived from algae. The attraction of algae is that they can have high oil content and, under suitable laboratory conditions, have demonstrated very high growth rates. If these high growth rates translate to correspondingly high biomass yields (tens and possibly hundreds of tonnes per hectare per year have been suggested) the implication is that land area would not be a constraint on production. Thus, while the key generational difference in ethanol production technologies was in the feedstock to fuel conversion process (the ability to use cellulose rather than starch feedstocks), for biodiesel production the difference is in the biomass yields.

For this illustration, biomass feedstock requirements for both canola seed and algae are assumed to be the same: 59,833 tonne (biomass) / PJ (biodiesel), corresponding to an assumed 40% oil content for both feedstocks.

Canola yield was shown in Figure 41 as constant at approximately 1.3 tonne/hectare/year.

In view of the technological uncertainties, algae yields of 3 and 10 tonne/hectare/year are tested. As will be seen, if significantly higher yields can be obtained, land area will not be a constraint.

Figure 40 showed the relatively small area of land currently devoted to canola production, about 1.0 Mha.

Figure 58 shows the consequences for net exports (in fact, substantial imports) of trying to meet biodiesel production demand for canola seed oil with no change to business-as-usual agricultural production. Biodiesel demand would be many times current canola production and would convert an export volume of 0.75 Mt/year to an import requirement of over 15 Mt/year.

Canola production could be increased – though this would be at the expense of other crop production. Figure 59 shows the crop land area implications if canola production were increased to the level of national self sufficiency (i.e. no trade in canola) and the area devoted to other crops reduced proportionately. The consequences of this for wheat exports are shown in Figure 60. Exports of other crops would, of course, also be affected. The feasibility of increasing canola production to this extent has not been examined. In general, canola would not be grown more often than every third year because of the need for disease control breaks. While, in theory, this would translate to an overall upper limit of one third of available cropland being devoted to canola, in practice, the design of suitable rotations with other crops and need to take account of local conditions would further reduce this limit.

Figures 61 and 62 show the consequences for crop land area (as in Figure 59) if algae with biomass yields of 3 and 10 tonne/hectare/year can supply biodiesel production needs. Clearly, if higher yields can be obtained land area will not be a constraint. These cropland area considerations are, in any case, notional because the algal production process is not dependent on the availability of fertile cropland.

Figure 58: Net exports of canola if the volumes of biodiesel in the low cost biodiesel from algae sensitivity case were produced from canola and there were no change in Australian canola production.

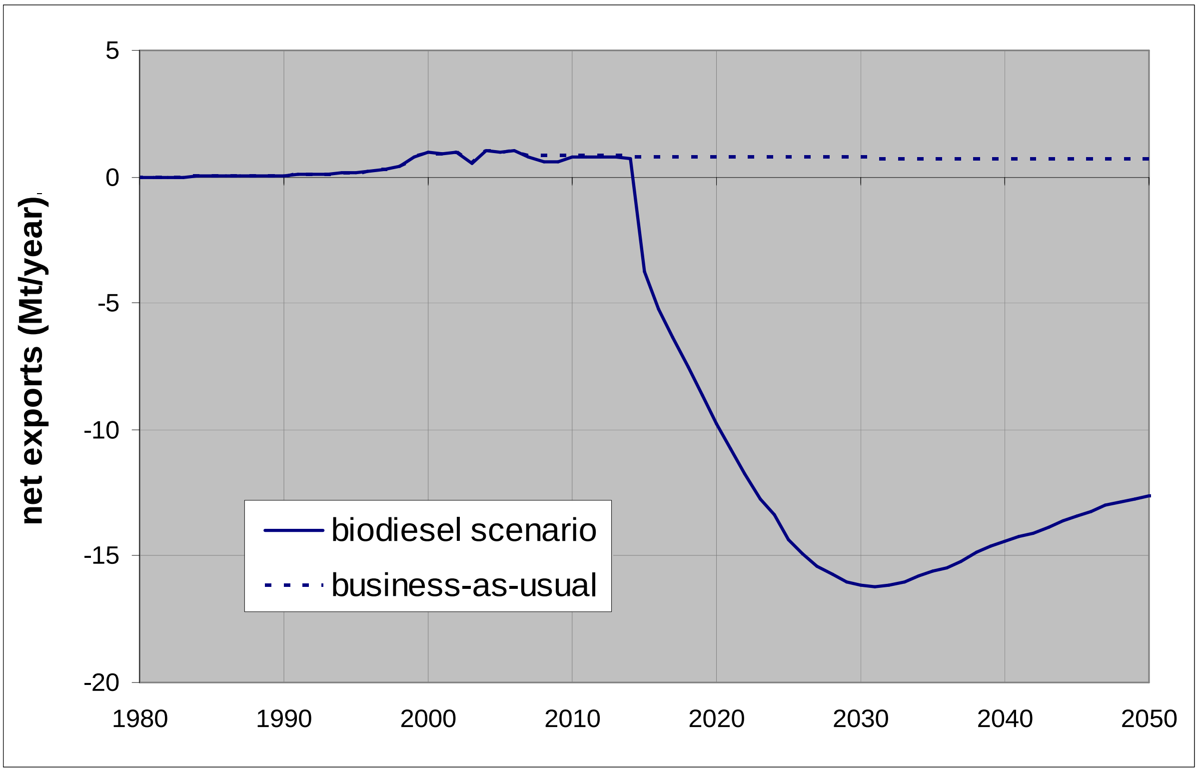


Figure 59: Increased land area for canola if the volumes of biodiesel in the low cost biodiesel from algae sensitivity case were produced from canola (other crop land reduced proportionately).

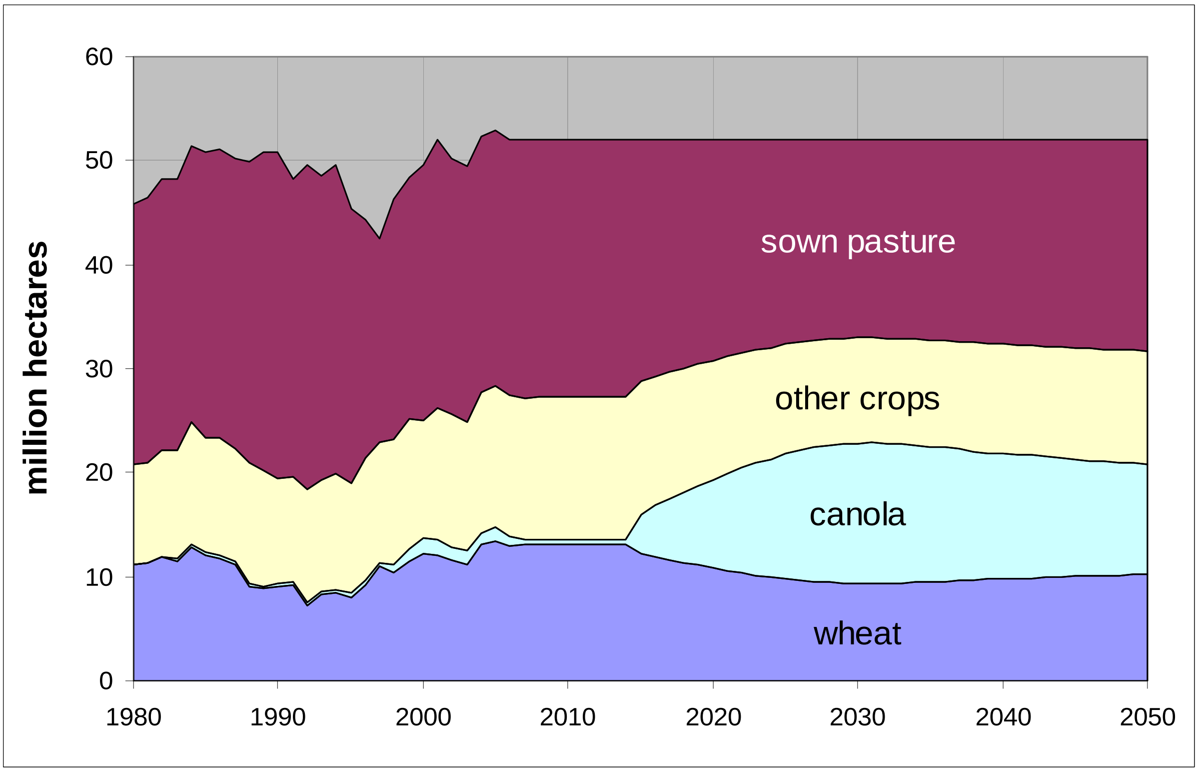


Figure 60: Consequences for wheat grain exports with canola production increased to meet biodiesel consumption volumes in the low cost biodiesel from algae sensitivity case.

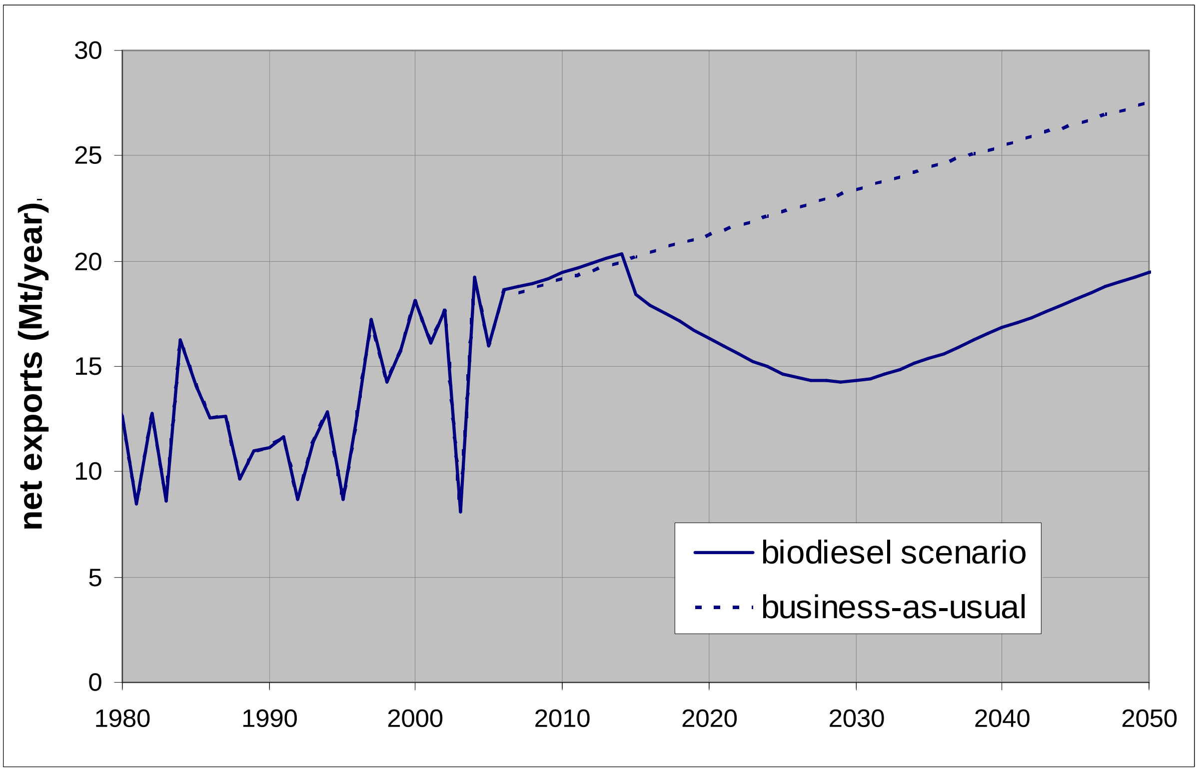


Figure 61: Consequences for crop land area of supplying biodiesel production requirements with oil from algae with biomass yield 3 t/ha/yr. Low cost biodiesel from algae scenario. Other crop land reduced proportionately.

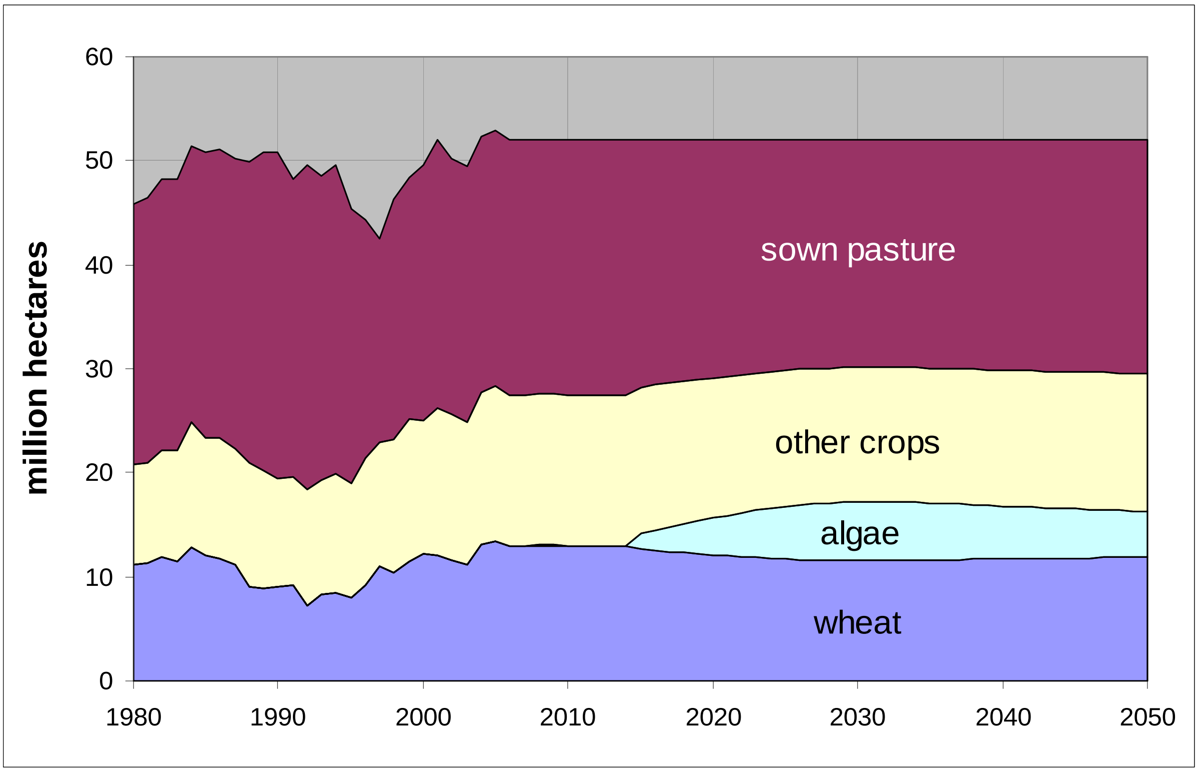
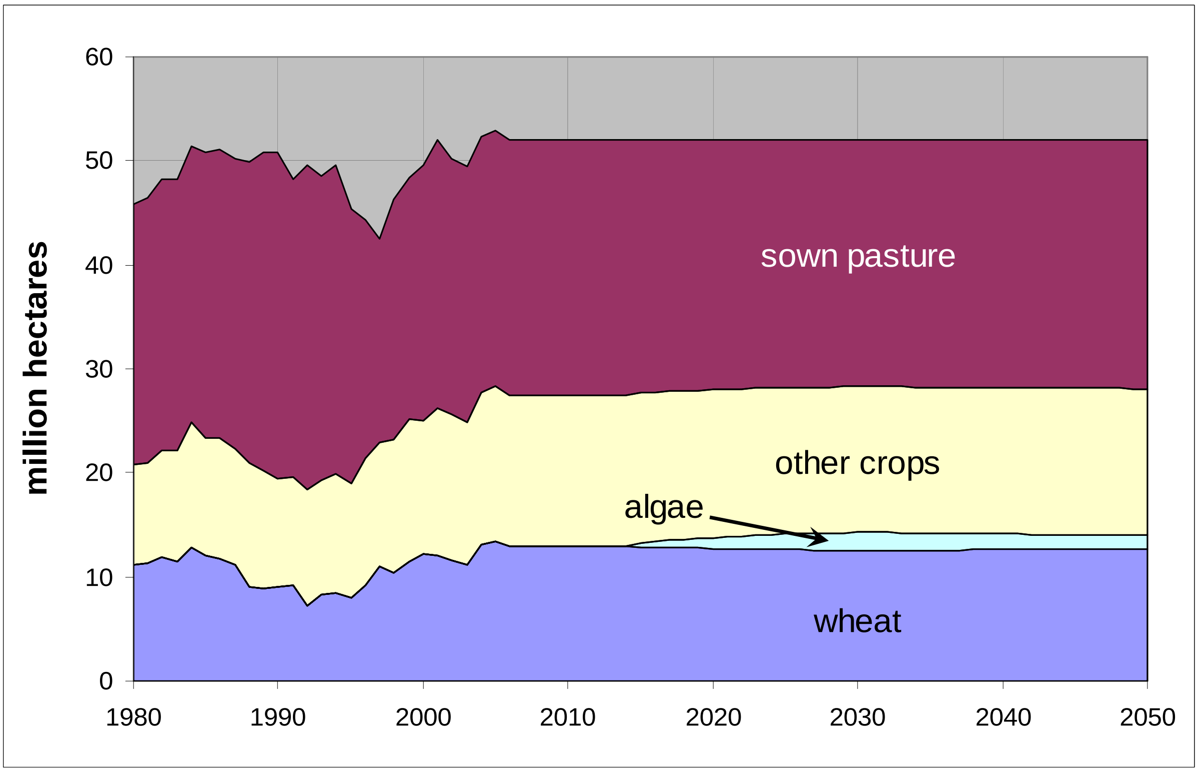


Figure 62: Consequences for crop land area of supplying biodiesel production requirements with oil from algae with biomass yield 10 t/ha/yr. Low cost biodiesel from algae scenario. Other crop land reduced proportionately.



Nuclear power as an option

Nuclear power is currently prohibited under Australia law and therefore if nuclear power were to enter the fuel mix it would need to be preceded by a change in majority public attitudes and consequent repeal or amendment of the relevant legislation. The inclusion of this sensitivity case is for the purposes of understanding what effect if any the presence or absence of nuclear power plants as an electricity generation option has on the modelling results. We do not speculate or attach any probability to the event of nuclear power not being prohibited in the future. The inclusion of this sensitivity case does not represent an endorsement of nuclear power as an option on the part of any or all Future Fuels Forum participants.

For the purposes of modelling this sensitivity cases we do not completely ignore the current illegal status of nuclear power. We acknowledge that nuclear power is currently prohibited and there would therefore be a significant delay before all the necessary regulations are in place to allow the first nuclear power plant to be fully completed. We impose a date of 2035 in the model as the earliest time at which electricity from a nuclear power plant would be supplied.

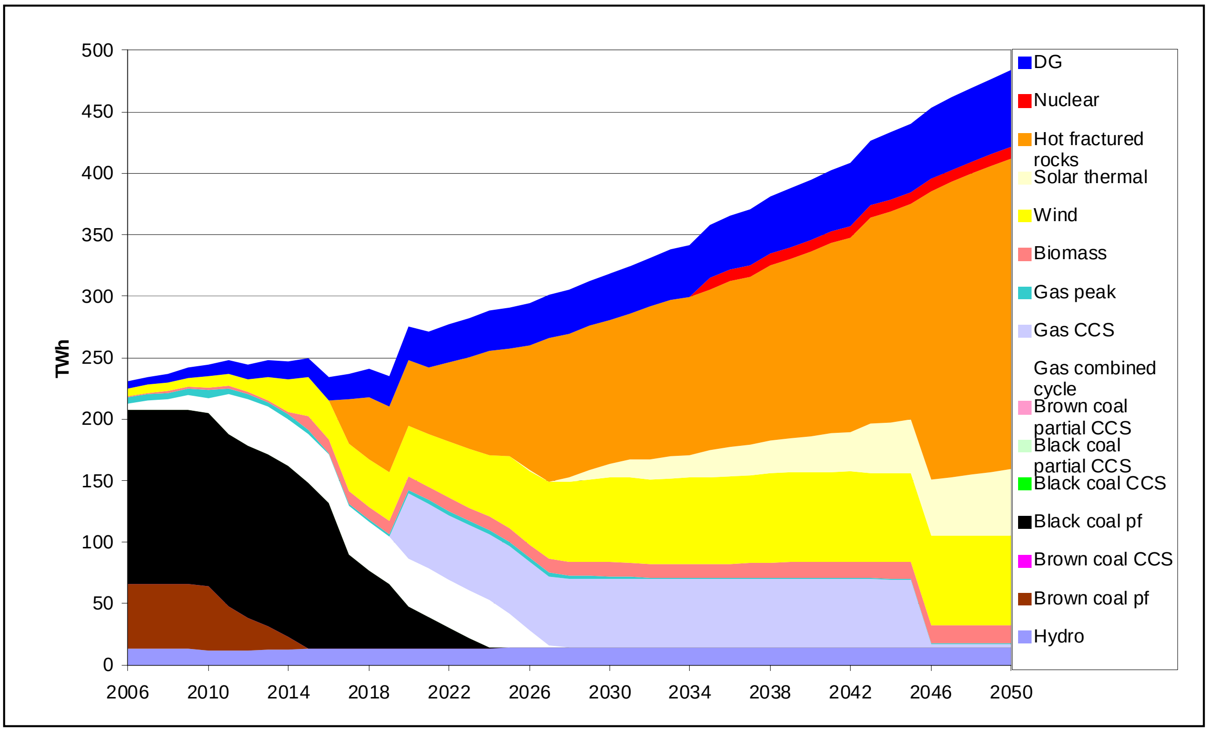
For the 2000-60 emission target the modelling shows that nuclear, although available as an option, makes no contribution to total electricity generation. This is because the other available options are lower cost at the prevailing CO_2e emission permit price. This result is a function of our technology cost assumptions in Appendix B.

However, nuclear power is economically viable in the scenario with the 2000-95 emission target. In this scenario nuclear power is taken up at the first opportunity, 2035, and accounts for around 10TWhs or 3 percent of electricity production.

Nuclear power does not expand beyond the initial investment in 2035 reflecting the model assumptions in Appendix B which project renewable electricity generation technologies will overtake nuclear power in terms of cost competiveness before 2050. Under these assumptions, timing is a strong driver of the maximum share that nuclear power achieves. If nuclear power had been able to be deployed earlier (prohibition is removed sooner) its market share would be higher. Nuclear power would also benefit if CO_2 capture and sequestration were unavailable as several studies have established (e.g. Energy Futures Forum, 2006; Graham et al., 2008).

Higher oil prices do not greatly affect the uptake of nuclear power as the total quantity of additional transport electricity demand does not significantly change the merit order of electricity generation technologies. The modelling did not consider transport fuel by-products from nuclear power such as hydrogen.

Figure 63: Electricity generation by technology: nuclear power as an option sensitivity case, EIA high oil price, 2000-95 emission target



The modelling results presented in Figure 63 show that hot fractured rocks and solar thermal electricity generation technologies are the main beneficiaries of the prohibition of nuclear power in terms of market share in the core scenarios. Since we have simply replaced one zero emission technology with another, the net effect on greenhouse gas emissions is indiscernible as shown in Figure 64.

Although there is no impact on the greenhouse gas emissions profile of the sensitivity case one would expect that by removing an option that was originally selected for its relative cost competitiveness that a higher cost of electricity that would be observable. However, given the small contribution of nuclear power this effect is not discernable. Figure 65 shows while there is some difference in price paths, those differences are minor.

Figure 64: Total transport and electricity sector greenhouse gas emissions: nuclear power as an option sensitivity analysis

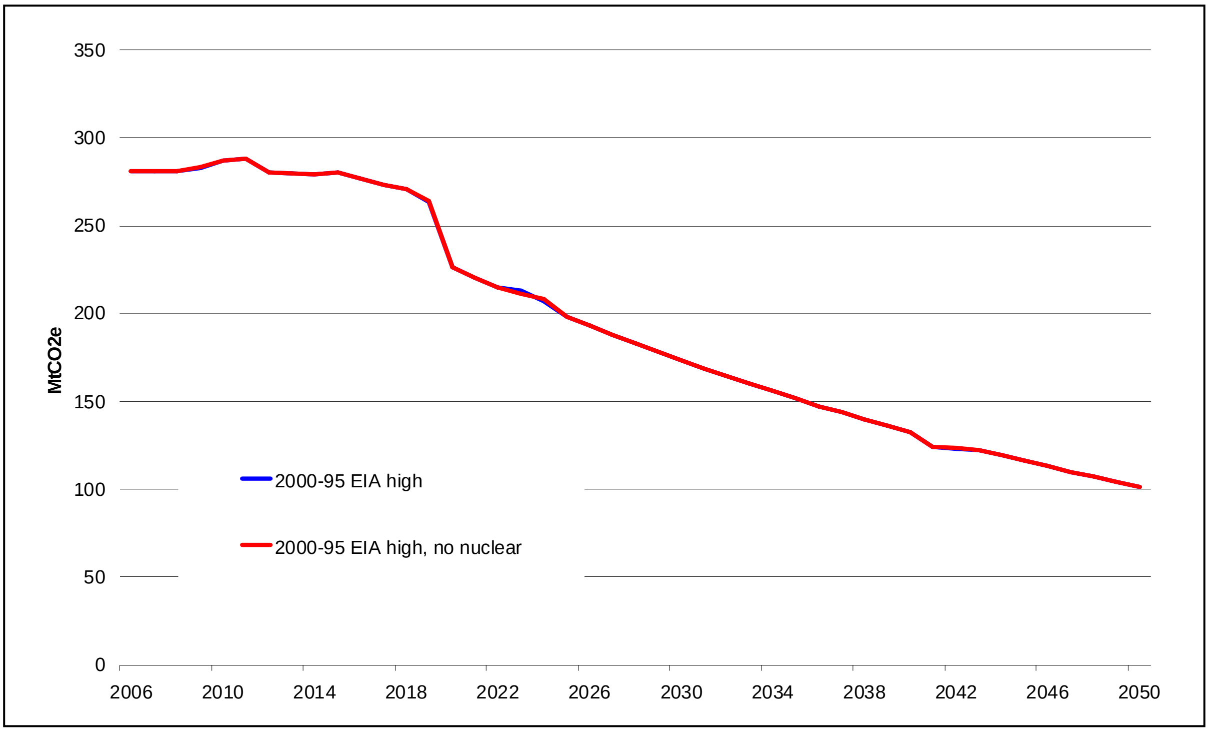
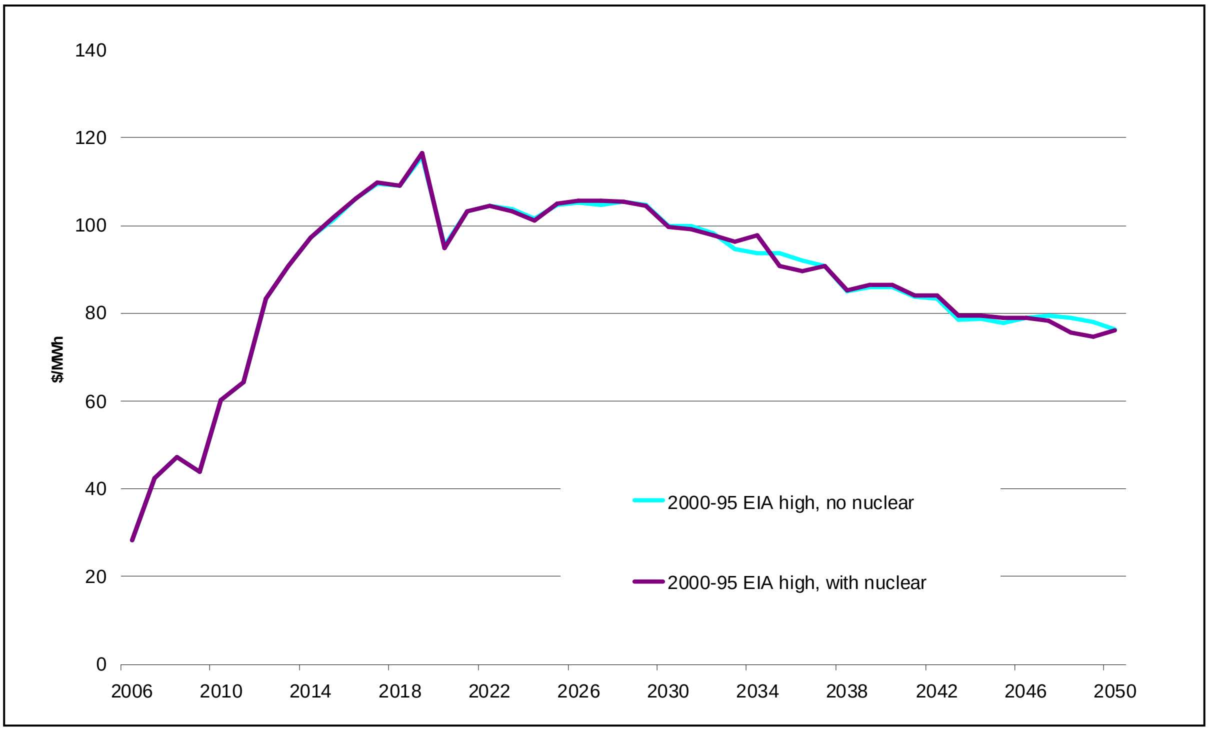


Figure 65: Wholesale electricity prices: nuclear power as an option sensitivity case



CO_2 capture and sequestration not available and electricity end-use efficiency higher

In our core scenarios, where the emission target is 60 percent below 1990 levels, CO_2 carbon capture and storage is a key low emission technology applied to both coal and gas. It also plays a significant albeit smaller role in the core scenarios with the 2000-95 target. The reliance on CO_2 carbon capture and storage is potentially a concern considering CO_2 carbon capture and storage is yet to be demonstrated at full scale and public awareness of the technology is only now growing slowly. The purpose of the following sensitivity case is to determine what would occur if CO_2 carbon capture and storage were unavailable for technical or social reasons. However, offsetting the narrowing of the technology options it is assumed that there is a focussed effort in Australia to improve electricity end-use efficiency over the long term such that the growth in electricity consumption in all sectors of the economy is reduced by 30 percent by 2050 relative to the core scenarios.

Where the emission target is 2000-60, the modelling results show that the emission reduction is achieved via greater uptake of wind, hot fractured rocks and natural gas electricity generation technology (Figure 66). Where the emission target is 2000-95, natural gas is too emission intensive so emission abatement is achieved by wind and, to a much larger extent, hot fractured rocks. Solar thermal electricity generation also plays a much larger role.

Figure 66: Electricity generation by technology: nuclear prohibited, CCS unavailable and electricity end-use efficiency higher sensitivity case, EIA high oil price, 2000-60 emission target

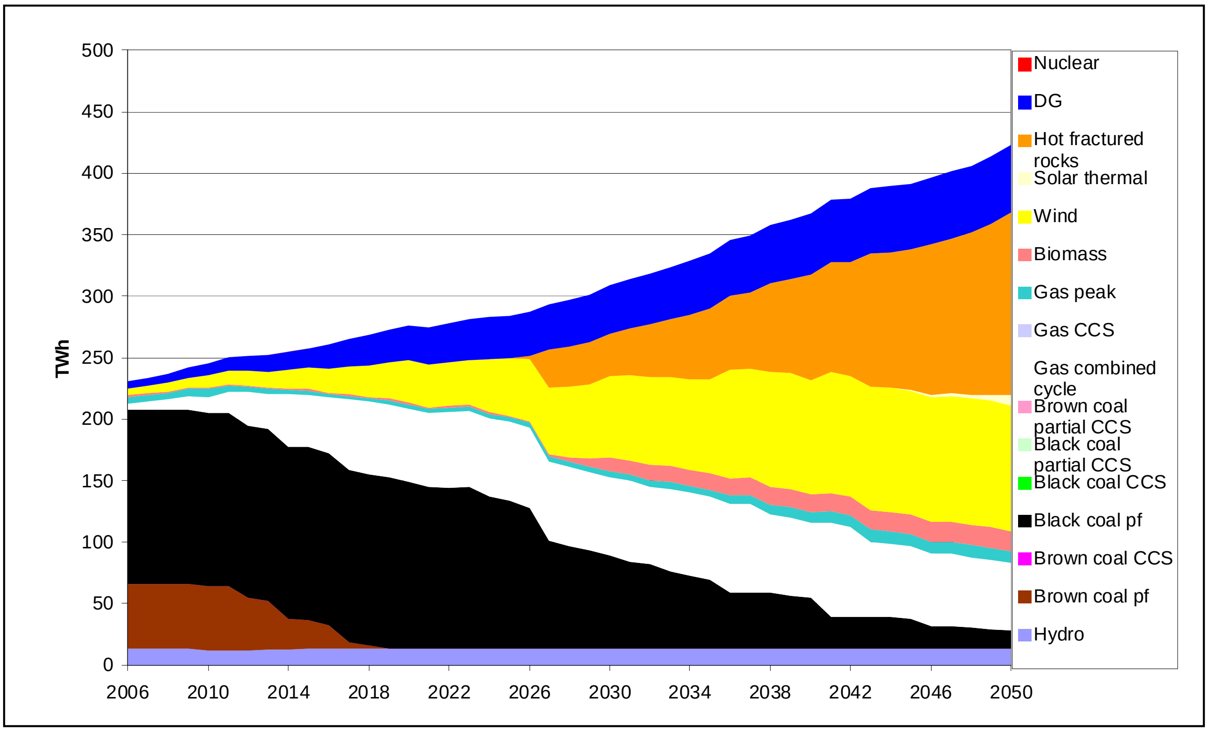
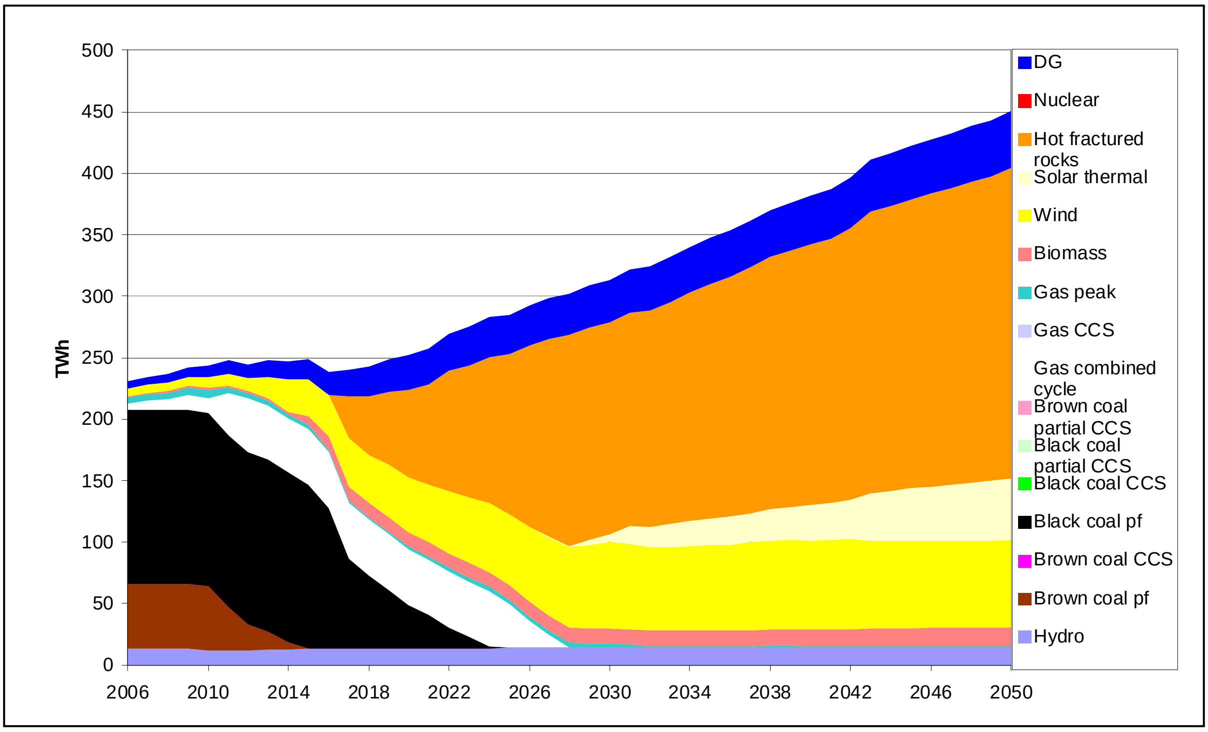


Figure 67: Electricity generation by technology: nuclear prohibited, CCS unavailable and electricity end-use efficiency higher sensitivity case, EIA high oil price, 2000-95 emission target



The absence of the option to take up CO_2 carbon capture and storage when and if they are cost competitive should mean that the model is selecting higher cost technologies sooner in response the emission trading scheme. This expectation is generally satisfied when we observe the wholesale electricity price, which simply reflects the long run cost of electricity generation.

In Figure 68, it can be seen that for both emission targets the wholesale electricity price is higher in the sensitivity case than in the core scenarios. When the emission target is 2000-60 the wholesale electricity price normally falls from around 2020 with the availability and uptake of CO_2 carbon capture and storage. When this option is not available the wholesale electricity price trends $5-7/MWh higher until the 2040s when the price difference is negligible.

When the emission target is 2000-95 the difference in wholesale prices is less significant. This is because CO_2 carbon capture and storage plays only a supporting role in the core scenarios when this emission target is applied. If available CO_2 carbon capture and storage would normally be taken up and applied to gas-fired power generation from 2020. When not available hot fractured rocks is taken up faster and in greater volumes at a time when its costs are higher. This results in wholesale electricity prices rising to around $3/MWh higher than if CO_2 carbon capture and storage were available for the decade between 2020 and 2030.

Note, since we have assumed this scenario has lower electricity demand growth, these price difference do not reflect differences in technology costs alone. If the sensitivity case had the same underlying rate of electricity demand growth (i.e. before price responses), then one could reasonably expect the price premium for removing CO_2 carbon capture and storage as an electricity generation option would be greater than calculated here.

The different electricity generation technology mix leads to very little difference in the greenhouse gas reduction achieved in the long run in the sensitivity case relative to the core scenarios. However in the medium term there are some observable impacts. The reason we see a different emission profile in the long term is mainly due to the absence of the option to use CO_2 carbon capture and storage. In the absence of this technology the market is forced to shut down existing high emission technology sooner and replace it with a combination of renewables and natural gas.

Figure 68: Wholesale electricity prices: CCS unavailable and higher electricity end-use efficiency sensitivity case

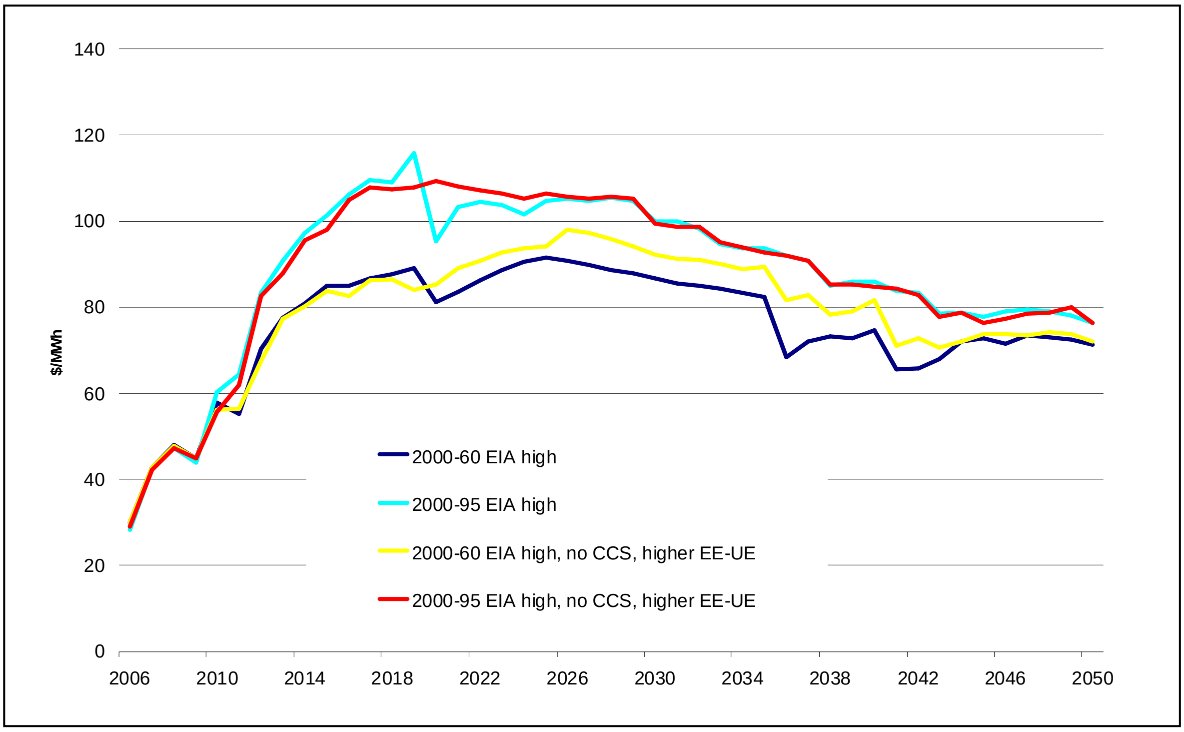
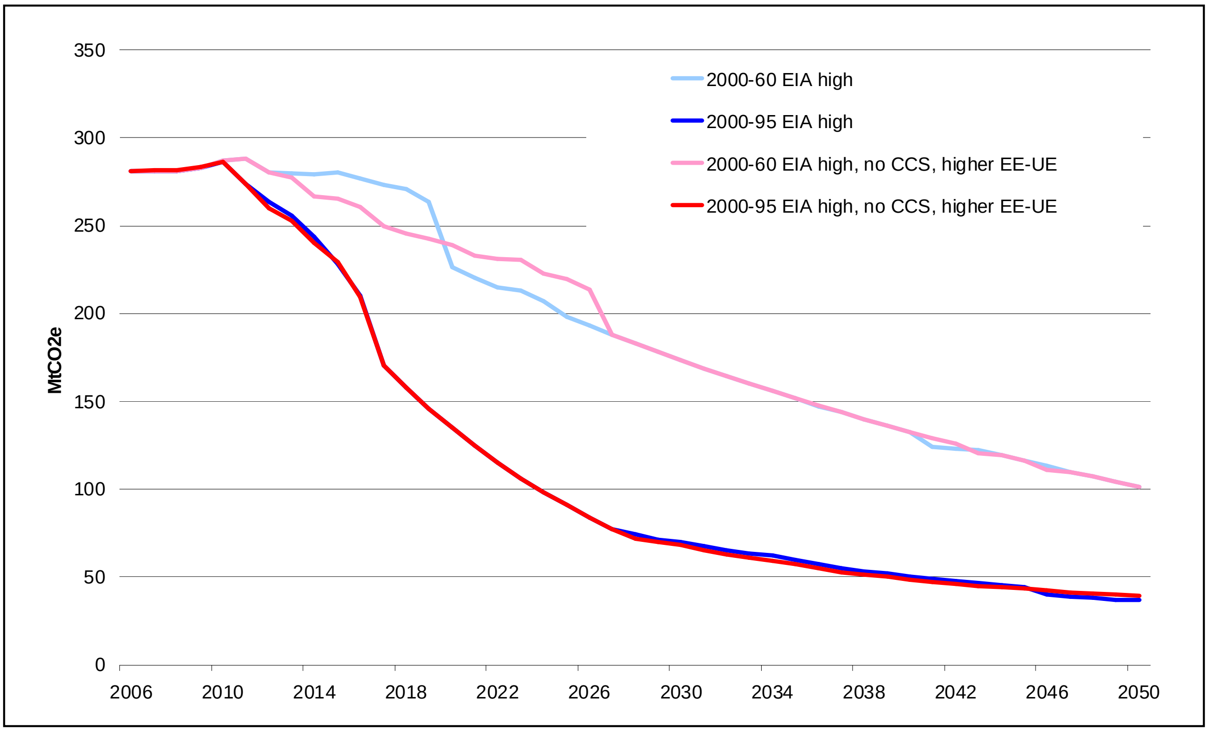


Figure 69: Electricity and transport sector greenhouse gas emissions: nuclear power prohibited, no CCS and higher electricity end-use efficiency sensitivity analysis



This means that in this sensitivity case emissions initially fall faster, particularly when the emission target is 2000-60 which has the higher uptake of CO_2 carbon capture and storage. However, from the time when CO_2 carbon capture and storage would normally have been taken up, around 2020, there is a period when emissions are higher in the sensitivity case than the core scenarios. This is because the absence of CO_2 carbon capture and storage has meant that the system is using more natural gas (which is two to three times more emission intensive than CO_2 carbon capture and storage) for longer. However, from the time zero emission hot fractured rocks begins to be taken up in earnest (2027) the emission profiles are almost identical.

For the 2000-95 emission target, emission reduction is slightly ahead of the core scenarios for the period between 2027 and 2047. This reflects the lower emission intensity of solar thermal power which is taken up instead of natural gas with CO_2 carbon capture and storage which although a very low emission technology still has some emission associated with the 10-15 percent of CO_2 not captured from such plants.

Sensitivity cases – declining oil supply and technology response

The core scenarios examining the possibility of declining international oil supply only examined what might be considered the two extremes – that the oil supply decline was slow and technology response was fast or that the oil decline was fast and the technology response slow. The analysis below fills in the possibilities in between. The specific assumptions of the sensitivity cases are shown along side the core scenario assumptions in Table 4. Not surprisingly the modelling results shown in Figure 70 and Figure 71 simply “fill in” the petrol price and fuel demand regions already explored in Figure 31 and Figure 32. We only shows the cases for the 2000-60 emission target. The results for the 2000-95 emission target are only slightly different.

The sensitivity cases do provide some insights. One is that the rate of decline in oil has a greater impact on petrol prices and subsequent decline in transport activity than the rate of availability of non-oil dependent technology. However, a better rate of availability of new technology could save up to $3.00/L. It could also shorten the period of high prices by around 4 to 8 years.

Table 4: Core (red) and sensitivity cases (green) for declining oil supply and rate of technology response

Scenario	Minimum rate of decline in oil based fuel consumption	Maximum rate of expansion in total production of alternative fuel vehicles [1]
Slow decline in oil supply with fast rate of increase in availability of alternative fuels and vehicles	3 percent per annum all modes 4 percent per annum road transport fuels	300,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Slow decline in oil supply with moderate rate of increase in availability of alternative fuels and vehicles	3 percent per annum all modes 4 percent per annum road transport fuels	75,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Slow decline in oil supply with fast rate of increase in availability of alternative fuels and vehicles	3 percent per annum all modes 4 percent per annum road transport fuels	15,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Fast decline in oil supply with fast rate of increase in availability of alternative fuels and vehicles	6 percent per annum all modes 10 percent per annum road transport fuels	300,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Fast decline in oil supply with moderate rate of increase in availability of alternative fuels and vehicles	6 percent per annum all modes 10 percent per annum road transport fuels	75,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter
Fast decline in oil supply with slow rate of increase in availability of alternative fuels and vehicles	6 percent per annum all modes 10 percent per annum road transport fuels	15,000 per annum in 2010 increasing by an additional 30,000 per annum thereafter

Figure 70: Core and sensitivity case scenarios for the petrol price required to ration demand in declining oil scenarios

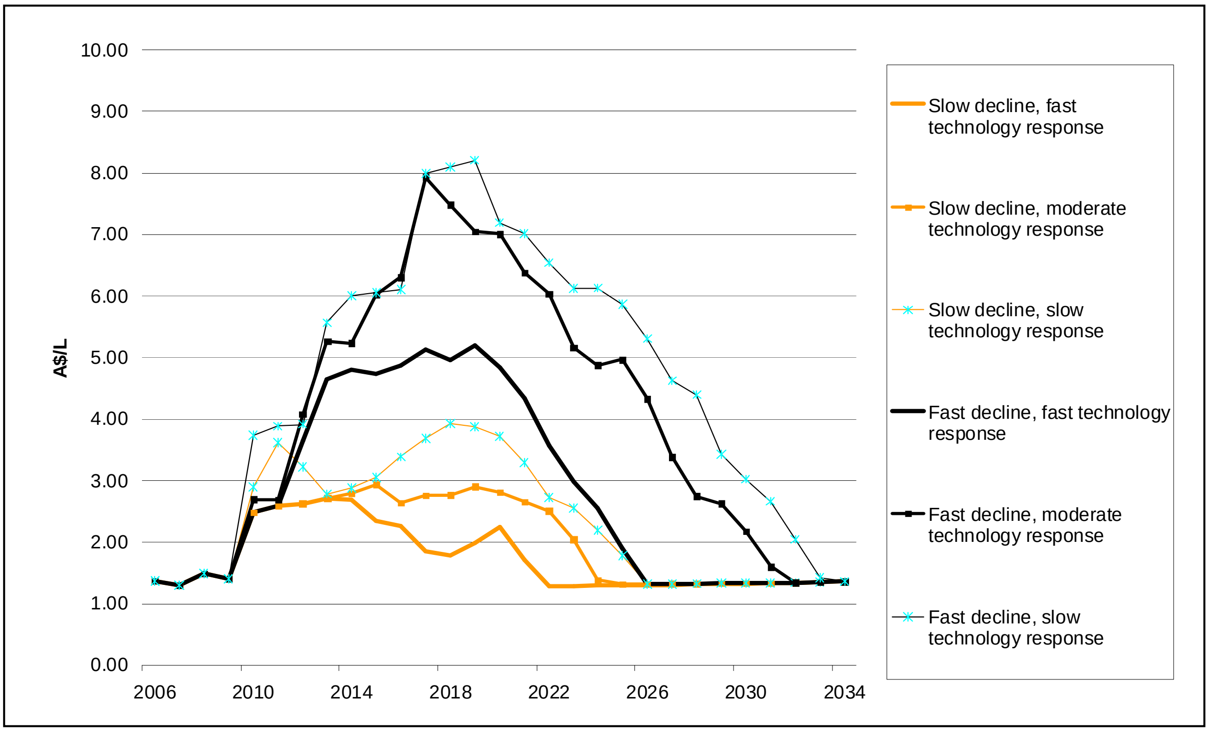
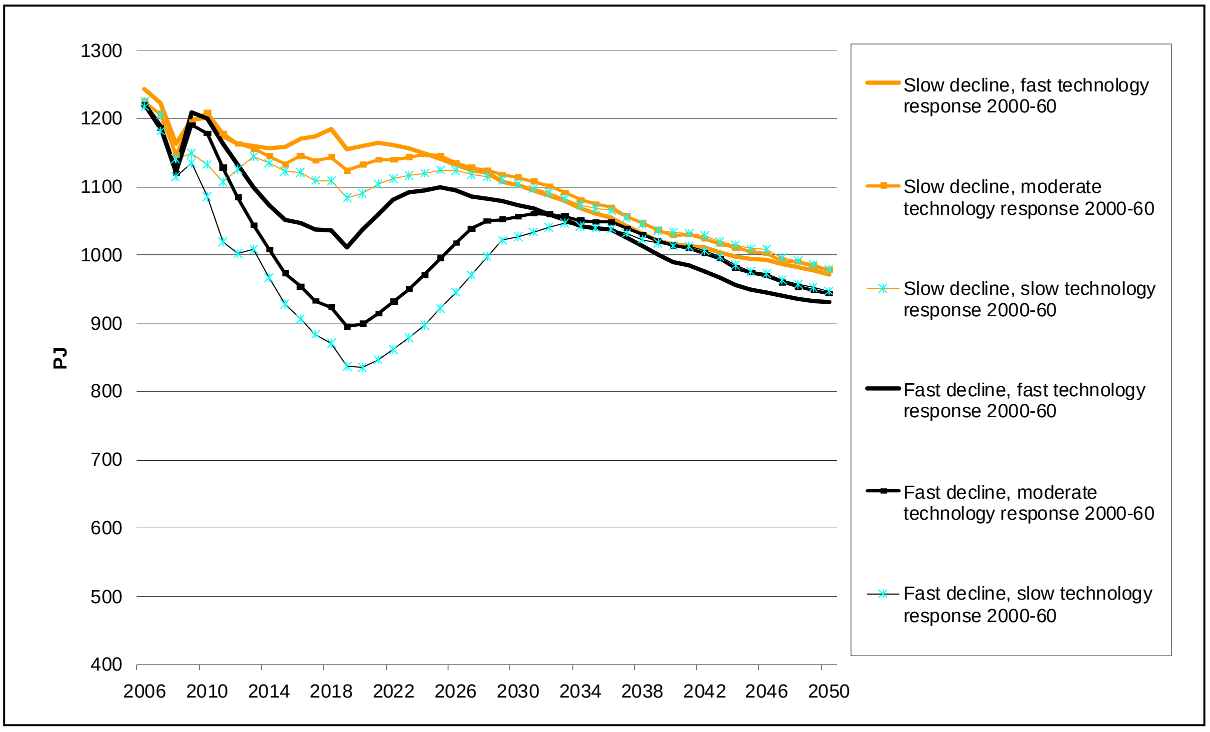


Figure 71: Core and sensitivity case scenarios for the demand for transport fuels when oil supply is declining, 2000-60 emission target



APPENDIX A - MODEL ASSUMPTIONS RELATING TO TRANSPORT

Proposed fuel/vehicle aggregation

An important consideration in the transport model is how to represent the fuel and vehicle combinations that are of interest. In theory one could construct a model of the Australian transport sector which included every make of existing vehicle and possible future vehicles. In practice, modellers will always seek to reduce the size of the vehicle fuel/technology set in order to make the model manageable in terms of data, model structure and mathematical solution speed and reliability.

For road transport, the proposed fuel and vehicle aggregation is as follows. Passenger and light commercial vehicles will be represented in three weight categories:

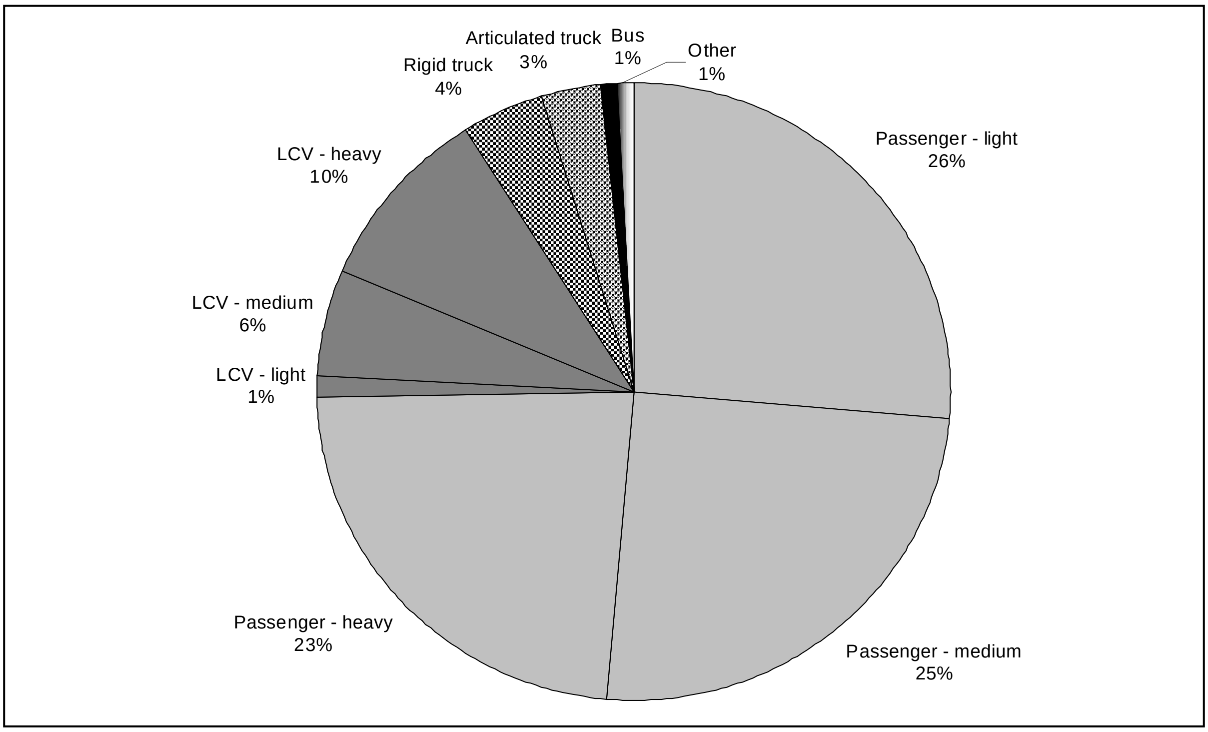
Light: less than 1200kg

Medium: 1200 to 1500kg

Heavy: 1500 to 3000kg

The remaining vehicle types will be rigid trucks, articulated trucks and buses. Motor cycles and campervans will not be specifically modelled but accounted for as a constant in the emission profile.

Figure 72: Current share of kilometres travelled within the road transport mode by vehicle type, 2006



Source: Adapted from Australian Bureau of Statistic data cubes

The fuels considered will be:

- Petrol – aggregating unleaded, lead replacement and premium
- Petrol with 10 percent ethanol (E10)
- Ethanol with 15 percent petrol blend (E85)
- Diesel
- Diesel with 20 percent biodiesel (B20)
- 100 percent biodiesel blend (B100)
- Liquefied petroleum gas (LPG)
- Compressed and liquefied natural gas (NG)
- Hydrogen produced from renewables (H_2)
- Gas to liquids diesel (GTLD)
- Coal to liquids diesel (CTLD) with upstream CO_2 capture and sequestration
- Electricity

This is obviously not a complete list of possible fuels but covers those which are generally of greatest interest for further study.

More categories of hydrogen production might be desirable. However, given the greatest cost associated with hydrogen is not the fuel but the cost of the storage system (and potentially the engine if a fuel cell is required), including additional cheaper hydrogen sources will make little difference in the modelling.

Compressed natural gas (CNG) is assumed to be used in all natural gas vehicles except for articulated trucks which use Liquefied natural gas (LNG).

The engine configurations allowed for are:

- Internal combustion
- Mild hybrid internal combustion-electric
- Plug-in hybrid electric (PHEV)
- Full (100 percent) electric

Fully electric vehicles were deemed to be only available in the light passenger and light commercial vehicle types due to range and power limitations. Conversely, hybrids were allowed in all other categories. Passenger and light commercial vehicle categories are available as PHEVs (internal combustion engine and electric motor on board capable of driving for extended periods) as are rigid trucks and buses. Articulated trucks were limited to mild hybridisation (for example, engine stop and fast start capability). The fuel efficiency section outlines what this means in performance terms.

Fuel cell vehicles are not specifically modelled but are in essentially an electric vehicle using on board electricity generation rather than battery storage. The additional cost of these vehicles and the electricity or fuel needed can be expected to improve over time. Whilst a battery solution is currently more cost effective fuel cells be competitive in the long term. That is, if the amortised cost of fuel cells plus their cost of fuel is better than the amortised cost of batteries and grid drawn electricity, then fuel cells will eventually dominate these new engine markets.

Fuel efficiency

Road vehicle fuel efficiency

The following road vehicle fuel assumptions have been adapted from Graham et al (2008).

The assumed fuel efficiencies of internal combustion engines for the year 2006 are shown in Table 5. The fuel efficiencies were based on the broad data contained in ABS (2007). Additional manipulations of the data were carried out for extension to different weight categories, to alternative fuels, to vehicles with hybrid powertrains, and for change over time. This approach, together with the methodology for electric vehicles, is detailed below.

Table 5: Average 2006 fuel efficiencies for internal combustion engine stock (L/100km, or m^3/100km for CNG and H_2)

	Petrol	Diesel	LPG	NG*	B100	B20	E85	E10	H2 (ren)	GTLD	CTLD
Passenger Cars											
Light	9.1	6.3	12.1	8.0	7.7	6.5	12.8	9.5	36.7	6.6	6.6
Medium	10.2	7.1	13.6	9.0	8.6	7.3	14.3	10.6	41.1	7.4	7.4
Heavy	14.0	9.7	18.6	12.3	11.8	10.0	19.6	14.5	56.3	10.1	10.1
LCVs											
Light	10.4	7.2	13.8	9.2	8.8	7.4	14.6	10.8	41.8	7.5	7.5
Medium	11.6	8.1	15.5	10.3	9.8	8.3	16.4	12.1	46.9	8.4	8.4
Heavy	15.9	11.1	21.2	14.0	13.5	11.4	22.4	16.5	64.2	11.5	11.5
Trucks											
Rigid	39.2	28.9	52.2	34.5	35.2	29.8	55.1	40.6	157.8	30.1	30.1
Articul'd	73.1	54.0	85.2	83.4	65.7	55.6	89.9	75.8	257.6	56.2	56.2
Buses	36.2	26.7	48.1	31.9	32.5	27.5	50.8	37.5	145.6	27.8	27.8

* Articulated trucks are assumed to be using LNG; all other categories are CNG

Base Data

For Passenger Cars and Light Commercial Vehicles, the ABS (2007) petrol and diesel data have been disaggregated into the proposed Light, Medium and Heavy weight categories. The approach relied on weightings of the vehicle stocks within those categories and fuel efficiency data for typical vehicles within that weight class, together with a correlation for vehicle fuel consumption and weight. Light Commercial vehicles were assumed to operate with a laden weight related to weight category, with a corresponding increase of 14 percent in fuel consumed relative to Passenger Cars.

For Trucks, the ABS (2007) petrol and diesel data have typically been applied. For operation of articulated trucks on petrol, an energy consumption increase of 20 percent has been assumed relative to the available diesel data. This methodology is discussed more fully in the following paragraphs.

Alternative Fuels

The efficiencies of fuels not currently in use and therefore not reported in ABS (2007) were calculated based on the relative energy content which is shown in Table 6. In some cases there is considerable uncertainty since energy content can vary, particularly for biofuels due to different feedstocks.

The energy content of reported fuels was used to determine generic energy consumptions for Spark Ignition (gasoline) or Compression Ignition (diesel) internal combustion engines. Each alternative fuel was associated with the energy consumption of either the SI or CI combustion process, and alternative fuel efficiencies were then determined according to the properties of the individual fuel.

The assumed relationship between fuel type and combustion process is presented in Table 7. For light duty vehicles, buses and rigid trucks, all variants of diesel fuel were assumed applicable to CI engines, the remainder to SI engines. For articulated trucks it was assumed that all fuels with the exception of gasoline and E10 were applicable to CI engines as performance requirements in this sector determine that CI diesel is dominant, and alternative fuel programs accordingly utilise the CI diesel architecture.

Table 6: Properties of selected fuels (/L, or /m^3 for CNG and H_2)

	LHV (MJ/kg)	Density (kg/L or kg/m^3)	LHV (MJ/L or MJ/m^3)
Petrol	42.7	0.75	31.9
Diesel	42.5	0.84	35.7
LPG	46.1	0.53	24.6
CNG	45.1	0.78	35.2
B100	40.2	0.84	33.8
B20	42.0	0.84	35.3
E85	29.2	0.78	22.8
E10	41.1	0.75	30.8
H2 (ren)	120.0	0.09	10.2
GTLD	40.0	0.84	33.6
CTLD	40.0	0.84	33.6

The Lower Heating Value (LHV) is used in deference to Higher Heating Value as the latent enthalpy of vaporisation for water vapour in exhaust gas is not recovered as useful work.

In some instances it is recognised that alternative fuel characteristics will adversely or beneficially affect the combustion process and in such cases the energy consumption is factored. The factoring is adjusted over time, as both the properties of alternative fuels and the deployment of appropriate engine technology are assumed to evolve.

Table 7: Combustion process according to fuel

	Petrol	Diesel	LPG	CNG	B100	B20	E100	E10	H_2 (ren)	GTLD	CTLD
Passenger Cars											
Light	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Medium	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Heavy	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
LCVs											
Light	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Medium	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Heavy	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Trucks											
Rigid	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Articulated	SI	CI	CI	CI	CI	CI	CI	SI	CI	CI	CI
Buses	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI

Note: Articulated trucks using LNG

Hybrid Powertrain

Hybrid electric vehicle fuel efficiencies were developed based on their performance relative to internal combustion engine only vehicles. Plug-in hybrids are assumed to use 50 percent less fuel initially (substituting electricity in its place) increasing to 80 percent by 2035. Mild hybrid vehicles are assumed to use 5 percent less fuel initially increasing to 30 percent. The exception is articulated trucks are assumed to achieve a maximum efficiency advantage of 10 percent due to their less stationary drive cycle.

Efficiency over time

The change in fuel efficiency over time is based on judgement of the balance of two competing forces. The first is improvements that have already or are likely to be achieved internationally where fuel excise rates are several times those in Australia. The second is the historical lack of improvement in fuel efficiency owing to:

- greater non-propulsion use of energy within the vehicle for amenities such as air conditioning (itself a function of growing wealth and consumer expectations)
- the trend towards large vehicles within some weight categories (particularly 4WDs/SUVs in the large vehicle category), and
- the robustness of households to fuel price changes owing to the small proposition of fuel costs in the household budget (amounting to no more than 2-3 percent of average adult annual income).

It is assumed that vehicles equipped with Spark Ignition (SI) engines will improve in efficiency by 25 percent and Compression Ignition (CI) engines by 14 percent from 2006 to 2050, independently of changes related to fuel type and hybrid drivetrain. These improvements are proposed to arise from increased efficiency of vehicle and engine technology in new vehicles, and the extent to which the existing fleet is modified by the addition of new vehicles.

Whilst equivalent vehicle improvements are assumed for both SI and CI vehicles, it is proposed that there is significantly greater scope to enhance the operating efficiency of the SI engine and that by 2050 the efficiencies of SI and CI engines will converge, with differentiation according only to the combustion characteristics of alternative fuel types. The efficiency of the SI engine is proposed to be increased through the following:

- optimisation of engine gas exchange processes and reduction of pumping work through the deployment of advanced valvetrains
- increase of compression ratio towards optimum values enabled by the use of direct injection and advanced valvetrains
- reduction in engine friction and the operation of engines in regions of highest efficiency enabled by down-sizing, in turn achieved by higher specific output with boosting, and
- operation at extended lean and dilute limits facilitated by advanced combustion processes, and enabled in part by the availability of lean emission aftertreatment and low-sulphur fuels.

Table 8: Average 2050 fuel efficiencies for internal combustion engine stock (L/100km or m^3/100km for CNG and H_2)

	Petrol	Diesel	LPG	NG*	B100	B20	E85	E10	H2 (ren)	GTLD	CTLD
Passenger Cars											
Light	6.8	5.4	8.6	5.5	6.3	5.6	8.6	7.1	23.3	5.7	5.7
Medium	7.6	6.1	9.6	6.2	7.1	6.3	9.6	7.9	26.1	6.4	6.4
Heavy	10.4	8.3	13.2	8.5	9.7	8.6	13.2	10.8	35.7	8.7	8.7
LCVs											
Light	7.8	6.2	9.8	6.3	7.2	6.4	9.8	8.0	26.6	6.5	6.5
Medium	8.7	7.0	11.0	7.0	8.1	7.2	11.0	9.0	29.7	7.2	7.2
Heavy	11.9	9.5	15.0	9.6	11.0	9.8	15.0	12.3	40.7	9.9	9.9
Trucks											
Rigid	29.3	24.9	37.0	23.7	28.8	25.6	37.0	30.3	100.1	25.9	25.9
Articul’d	54.6	46.4	69.7	68.3	53.8	47.8	69.6	56.6	199.4	48.4	48.4
Buses	27.0	23.0	34.1	21.9	26.6	23.6	34.1	28.0	92.4	23.9	23.9

* Articulated trucks are assumed to be using LNG; all other categories are CNG

The higher efficiency of the CI engine is achieved by already addressing many of the shortcomings of the SI combustion process, although with an accompanying deterioration in tailpipe emissions. The potential for further increase in efficiency is therefore limited, and moreover the challenge to meet future emission standards presents a risk to maintaining the present levels of efficiency. The increase in CI engine efficiency is attributed primarily therefore to the availability of European designed diesel engines which up until recently were not compatible with our diesel fuel as set by the national standards. Recent light passenger diesel vehicles are being promoted as achieving 3 L/100km; however it will take considerable time for the average efficiency to reach this level.

Projected fuel efficiencies at 2050 which account for trends in vehicle and engine efficiencies, together with projections for alternative fuel factors, are presented in Table 8.

Electric and plug-in electric vehicles

The fuel efficiency of the electric vehicles in the light vehicle categories is assumed to be 0.2kWh/km. It is assumed that this efficiency will remain unchanged through time because any improvement in available energy will be used to improve the amenity of the vehicle (e.g., passenger and luggage room, safety, comfort, instruments) rather than its fuel efficiency. Note, at a residential electricity price of 12c/kWh, the cost of electricity as a fuel is 4.2c/km. This is slightly more than a third of the cost of fuel for a petrol vehicle in the same weight class of 11.5c/km at a petrol price of 128c/L (the price of petrol in the base year, 2006, of ESM).

PHEVs are assumed to be powered by electric battery for 80 per cent of their kilometres in a given year. PHEVs are assumed available in the medium (1200–1500kg) and heavy (greater than 1500kg) passenger and commercial vehicle categories. When operating on battery mode, the fuel efficiency of medium-weighted PHEVs is 0.22 kWh/km and heavy-weighted PHEVs is 0.31 kWh/km.

Non-road vehicle fuel efficiency

Vehicles associated with rail, air and sea consume a much greater amount of fuel on account of their extra load per trip, or in the case of air extra load and flight.

Table 9: Indicative ranges for efficiency of non-road transport

Mode & technology	MJ/passkm - current		MJ/passkm - future		MJ/tonnekm - current		MJ/tonnekm - future	
	Passenger		Passenger		Freight		Freight	
	BE	Range	BE	Range	BE	Range	BE	Range
Rail – urban	0.5	0.18-0.83	0.33	0.1-0.5	0.5	0.33-0.95	0.3	0.1-0.5
Rail – suburban	1	0.5-1.1	0.6	0.4-0.8	0.35	0.1-0.5	0.24	0.08-0.4
Rail – high speed	0.55	0.47-0.7	0.3	0.15-0.4				
Aviation	2.7	1.6-3.3	1.1	0.7-2	5	4.5-39	2.2	
Water – ferry/coast	3.6				0.15	0.1-0.2	0.13	

Sources: various. BE – best estimate

The average energy efficiency across the whole fleet for rail, air and sea is 139, 550 and 50 MJ/km respectively compared to around 3 to 23 MJ/km for cars and trucks.

Of course there are many different size planes and ships and rail can be broken up into urban passenger versus freight. The data below gives an indication of the spread of data. Note: to convert back to kilometres multiply passenger kilometres and tonne kilometres by number of passenger or tonnes carried respectively.

Based on the data above and other sources rail, aviation and sea fleet fuel efficiency is assumed to improve by 30, 20 and 20 percent respectively by 2050. In regard to aviation, whilst more efficient aircraft are feasible, the 20 percent figure largely reflects the coming change in the aviation fleet which will then stay locked in for several decades due to the long life of aircraft.

Vehicle emission factors

Road sector emissions

Direct emission factors for the main fuels we use today have been calculated from values provided in Department of Climate Change (2008) with some adjustment for upstream or indirect emissions and for less common fuels from CSIRO internal data.

The full fuel cycle emission factors in grams per kilometre for road vehicles are shown in Table 6. It can be expected that estimates of upstream emission factors will change over time. For example, the science is still being developed around the impact of extracting fuels from biomass. A second example is that the conversion process for coal and gas to liquids are still being actively improved. One final example is that some fossil fuels, such as oil, may become more difficult to extract, therefore requiring more use of energy upstream. Ideally these changes should be incorporated. However, currently there is not enough reliable data to do so. Downstream or direct emission factors can be expected to improve because of improvements in fuel efficiency - this is incorporated in the modelling.

Table 10: Full fuel cycle CO_2-e emission factors for each fuel and road vehicle category (g/km)

	Passenger Vehicle			**LCVs**			**Trucks**		**Bus**
	Light	**Med.**	**Heavy**	**Light**	**Med.**	**Heavy**	**Rigid**	**Art'd**	
Petrol	215	240	329	245	274	375	923	1722	852
Diesel	175	196	268	200	223	306	800	1493	738
LPG	195	218	298	222	248	340	836	1365	772
CNG	203	227	311	232	259	355	873	1426	806
B100	21	23	32	25	26	36	104	198	101
B20	131	147	201	157	168	229	664	1183	609
E85	170	190	260	194	217	296	729	1360	358
E10	213	238	326	242	271	372	914	1715	852
GTL Diesel	175	196	268	200	223	306	800	1493	738
CTL Diesel	333	372	510	379	424	581	1518	2833	1398
Hydrogen (ren.)	0	0	0	0	0	0	0	0	0

Electricity fuel is not assigned an emission factor because its emissions are accounted for in the electricity sector.

Non-road emissions

Emissions for non-road vehicles are simply calculated by multiplying through the Department of Climate Change (2008) emission factors in kg CO_2e per MJ by the fuel efficiencies assumed in the section above.

Apart from improved fuel efficiency, growth in emissions from the non-road transport sector are reduced by the following assumptions:

- The share of electrical energy in total rail energy consumptions increases from 20 to 50 percent by 2050
- The share of biofuels in sea and air travel energy use increases from near zero to 10 and 5 percent respectively by 2050 with uptake beginning from 2020.

The growth in demand for non-road transport is also a significant determinant of emissions. However, since they are a scenario driver, default assumptions are not discussed here. The section on Transport Services Demand below gives an overview of past trends.

Transport costs

One of the key functions of ESM is to determine the uptake of fuel and engine technologies. These can be imposed but the default process is for the model to choose the least cost response to whatever drivers are in force (such as carbon pricing). In order for the model to give a plausible answer it must, as a minimum, be provided with data to compare the relative economic merits of the vehicles that would be under consideration by the consumer (or investor).

Non-fuel costs

Table 11 sets out the major categories of non-fuel costs and sources of data for them. Basic vehicle costs are only meant to be representative of the median vehicle in their vehicle category. There is a wide margin of error. However, it can not be easily avoided given the need for aggregation (see previous section). Maintenance costs are calculated via bottom up analysis of the minimum maintenance expenditure required to renew registration of the vehicle (e.g. tyre change every two years, minimal oil and battery replacement). In addition to regular maintenance, major part replacement is assumed to become part of the maintenance cost of older vehicles (> 5 years).

For some alternative fuels, there is little or no information available with respect to additional vehicle cost for the alternative fuel to be incorporated. In these cases, estimates have been made based on the ratio of costs in the next most relevant vehicle category.

In constructing non-fuel costs, the data has relied on a wide variety of predominantly web based sources and may be poor in some cases. To test the validity of the data it is compared with the NRMA's Private Whole of Life Vehicle Operating Costs Report.

Table 11: Non-fuel cost categories in total travel cost

Non-fuel cost category	**Data source**
Basic vehicle cost	Passenger and light commercial: NRMA *Open Road* Trucks and buses: Manufacturers websites Electric vehicles: e.g. http://www.electric-echo.com/prices.htm
On-costs above basic vehicle cost to accommodate alternative fuel	Various manufacturer websites
Insurance – third party and comprehensive	Insurance companies (e.g. AAMI, NRMA)
Registration	State government transport authority/department websites
Maintenance	Web sources on tyres, oil, batteries and servicing

The comparison is shown in Table 8. To simplify the comparison we have used the same fuel costs as quoted in the NRMA report which was an unleaded petrol price of 125.8c/L.

Table 12: Comparison of whole of life transport cost estimates for petrol passenger vehicles (c/km)

Category	NRMA estimate	CSIRO estimate
Small/light	48.5	41.9
Medium	63.6	60.6
Large	69.9	76.3

NRMA has based the above estimates on the Holden Viva, Holden Epica and Mitsubishi 380 for the light, medium and large vehicle categories respectively. The CSIRO estimates differ in absolute terms mainly in the light and large vehicle categories but this was to be expected. Our estimates represent an average of vehicle costs in defined weight categories. For the light vehicle category, the Viva would be at the high end of our weight range so that our estimate would be expected to be lower than NRMA's. Similarly, the Mitsubishi 380 would be at the low end of the weight range so that our estimate would be expected to be higher.

Costs of rigid trucks are 95-140c/km. Costs for articulated trucks are 100-180c/km. Costs for buses are 175-250c/km. There are fewer references for comparison of these costs.

It is assumed that all internal combustion vehicle purchase costs and all other non-fuel costs rise with the level of inflation and therefore remain constant in real terms. By comparing older issues of NRMA's *Open Road*, this assumption holds true for the last 4 years for medium and heavy passenger vehicles. There was a real reduction in vehicle purchase costs for some light vehicles but this is assumed to have run its course. Going further back to the 1980s there is a definite trend of declining real costs, however it is assumed that trend will no longer apply due to changed world resource supply and demand conditions. The major risk is that strong growth in demand for metals worldwide may cause the price of vehicles to rise faster than inflation for a period before metal production accelerates to meet demand.

Some improvements in costs are assumed for electric, mild hybrid and PHEV vehicles. The cost assumptions for two points in time, 2006 and 2025 are shown in Table 15. The assumption regarding hybrid vehicles is that over two decades mild hybridisation of vehicles will become standard and will not involve significant additional cost. However, mild hybridisation is not widely available at present and so additional costs begin at a high level. For fully electric vehicles which are only considered in the light car category the price gap is just under $10,000. Only retrofitted vehicles are currently available. Therefore, we assume no improvement in this gap until mass production built for purpose vehicles are available. This is assumed to occur during the next two decades. By 2035, the price gap is assumed to have closed to match a light weight petrol fuelled internal combustion vehicle.

PHEVs are expected to always cost a premium over a standard internal combustion vehicle in the same vehicle category. Starting from a relative cost gap of around $20,000 to $40,000, costs are expected to narrow to less than an additional $10,000 in the next two decades.

These estimates of costs are sourced from a number of industry articles on the relative costs of hybrids, plug-ins and electric vehicles. See Peckham (2007) for example.

Table 13: Assumed current and future representative vehicle costs, $’000.

	Passenger Vehicle			**LCVs**			**Trucks**		**Bus**
	Light	**Med.**	**Heavy**	**Light**	**Med.**	**Heavy**	**Rigid**	**Art’d**	
2006									
Base (ICE)*	14	25	41	14	25	41	61	300	180
Mild hybrid		28	44		28	44	100	370	260
PHEV		48	64		48	64	160		
All electric	24			24			121		
2025									
Base (ICE)*	14	25	41	14	25	41	61	300	180
Mild hybrid		26	42		26	42	61	300	180
PHEV		34	50		34	50	87		
All electric	17			17			76		

*The standard internal combustion engine (ICE) vehicle is considered to be a representative base vehicle for the category and weight class given.

Future fuel costs

The oil price will be a scenario driver and therefore default assumptions are not defined here. The assumed oil price forecast for each scenario will be the basis of the change in retail prices for the fossil fuel categories which are directly linked to the oil price. That is, we will assume that fossil fuel based liquid fuels achieve price parity adjusted for their relative energy content.

The cost of CO_2 capture and storage for coal to liquids diesel is assumed to be \$20/t CO_2e. The discussion below in Electricity finds from several studies that the cost of CO_2 storage is projected to be \$10/t CO_2e. The balance of costs, that is the capture component, is also assumed to be \$10/t CO_2e on the basis that capture technology will likely be demonstrated at very large scale in the electricity sector first and will therefore be available at reasonable cost to other sectors. Both coal to liquids diesel and gas to liquids diesel are assumed to be available only after 2020.

The retail price of electricity for full electric vehicles will be calculated simultaneously as an output of changes in the electricity generation sector in the scenario.

For the biofuels, biodiesel and ethanol, the cost will be based on the volume of demand as per the cost-quantity curves in Figure 68 and Figure 69. These curves are derived from O'Connell et al. (2007) and have been updated further to take account of recent price movements. Due to competition with the food production industry, it is assumed that only 5 percent of this volume is available within the next decade. The exception is all used cooking oil and all tallow not exported is assumed to be available for biodiesel.

From 2020 technology is assumed to be available to use lignocellulose feedstock in ethanol production. It is assumed this volume enters at the lower end of the cost-quantity curve. As a guide to volumes around 30 percent crop residue could be used equivalent to 9000ML (O'Connell et al., 2007). However, feedstocks could also include specialty crops and wood/wood waste. If economically viable this could contribute to around 20 percent current fuel requirements.

Similarly, for biodiesel we assume algae-based sources are available from 2020 and as a result increase the volume of biodiesel available by a factor of ten. It is assumed this volume enters at the upper end of the cost quantity curve.

Prices of all biofuel feedstocks are assumed to decline by 25 percent from 2020.

Figure 73: Biodiesel cost-quantity curve excluding algae

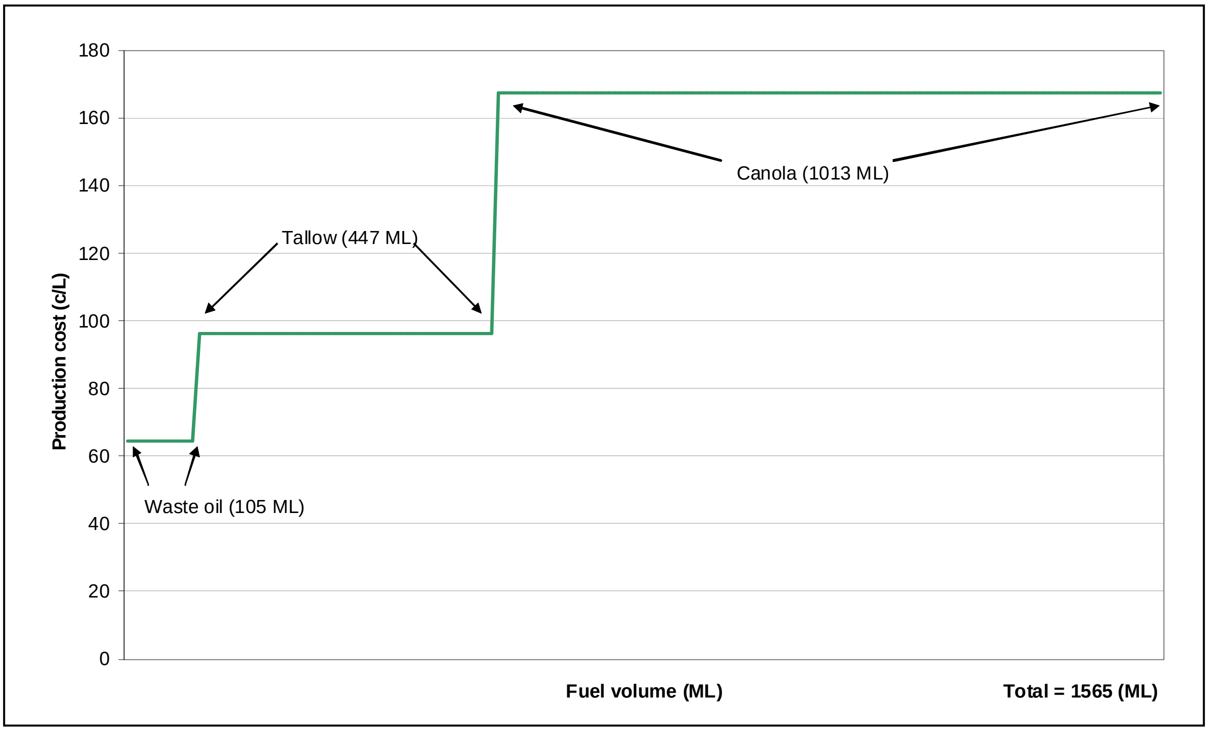
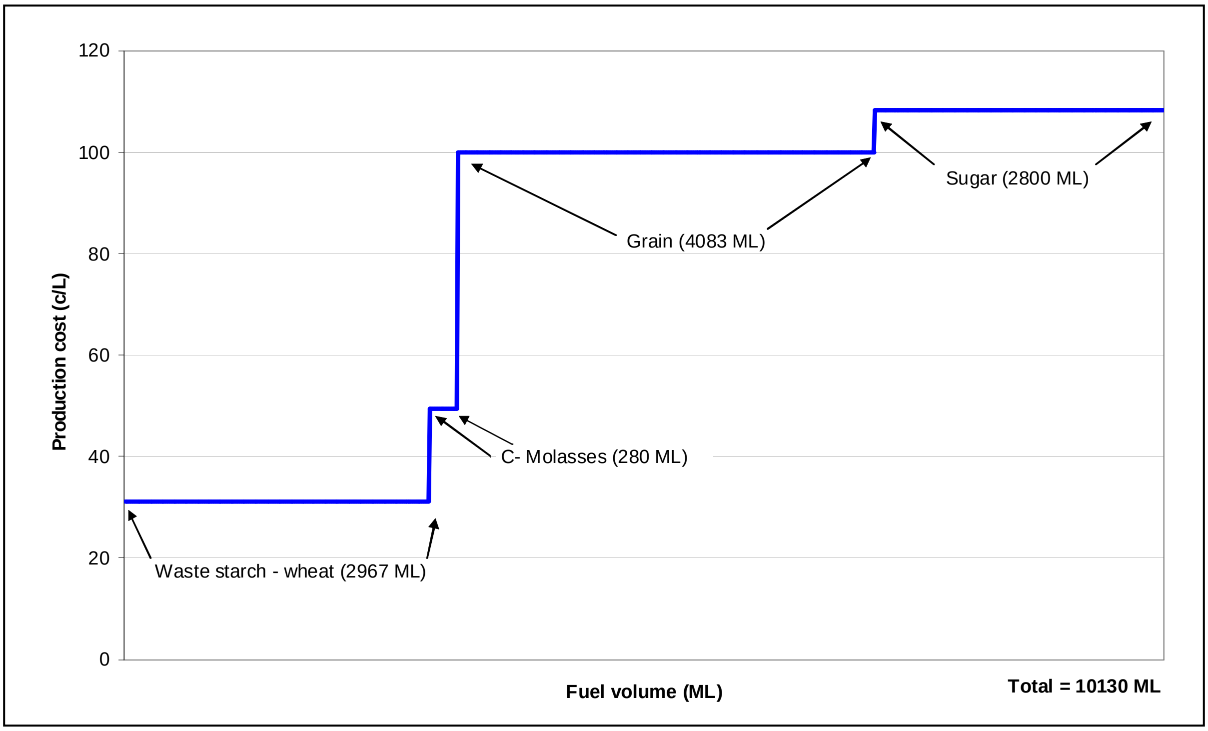


Figure 74: Ethanol cost-quantity curve excluding cellulose



Default transport policy settings

While the scenarios will explore policy development in various areas, the default settings will include policy that have been announced or are currently in place.

City planning and infrastructure investment are implied by the assumptions in the section on transport services demand and fuel efficiency. This section outlines three additional polices being the cost of vehicle registration, excise rates and the New South Wales ethanol mandate.

Vehicle registration

Most states provide vehicle registration fees on stepped scale with lower fees being for smaller vehicles. Victoria is an exception (based on postcode). Pensioners and other groups also receive rebates. Victoria provides a $50 rebate for hybrid electric vehicles. It is assumed these policy settings remain in place and the cost of registration is maintained in real terms. Trucks and buses registration costs are set nationally and also increase with size.

Excise rates

National excise rates have recently been re-designed and set in nominal terms. They will gradually phase in a system of rates based on groupings of similar levels of energy content across the full range of conventional and alternative fuels. Alternative fuels will be more costly as a result but still discounted relative to conventional fuels. The phase-in period is to 2015

It will be assumed that the level of excise in 2015 remains constant in nominal terms. As a result, excise rates are declining in real terms.

New South Wales ethanol mandate

Under the NSW Government’s 2 percent ethanol mandate, primary petrol wholesalers will need to ensure that ethanol makes up a minimum of 2 percent of the total volume of NSW sales. Not all fuels sold will contain ethanol but the consumer has the choice of filling up with E10 petrol (contains a blend of 10% ethanol).

The New South Wales mandate will be directly applied in the model as a constraint on the minimum use of E10 in fuel consumption.

Transport services demand

The factors influencing growth in transport demand, both in terms of kilometres and vehicle fleet numbers are complex and can be largely grouped under the following categories:

- Changes in social patterns (such as the ageing of the population, changes in household structure)
- Changes in the structure of our cities (particularly land use and transport patterns)
- Changes in economic circumstances (e.g. household affluence and vehicle affordability)
- Changes in transport mode choice

The individual influence of each of these factors cannot be easily isolated.

Passenger vehicles occupy the largest share of the fleet and the vehicle kilometres travelled. Rail, air and sea kilometres travelled and fleet size are small by comparison to road vehicles. However, because they are carrying heavy loads, these modes are using more fuel per kilometre travelled. While this balances out fuel consumption to some extent, road transport is still responsible for around 90 percent of fuel consumption and greenhouse gas emissions.

Demand for road passenger kilometres is generally pegged to population growth which is projected to grow marginally over 1 percent. The slow growth is on account of the saturation effect with respect to car ownership which means that growth cannot exceed population growth unless there is more time available to travel. Most commentators agree that, whilst some growth is possible the limit is fast approaching in term of the amount of fast road infrastructure that can be accommodated, feasible commuting times and work-life balance.

Demand for all other road transport tends to be more closely related to growth in GDP. For example, the income elasticities generally applied to commercial road transport are around 1.1 (BTCE, 1995). This implies average annual growth in GDP of around 2.5 percent will lead to slightly more than 2.5 percent growth in commercial road transport

Default demand growth settings

Given that the scenarios explored by the Future Fuels Forum all involve greenhouse gas reduction and high oil prices it is assumed that social and cultural preferences relating to transport demand will make a structural break from the past and support lower growth in kilometres travelled and fuel use. We are able to reflect changed social and cultural preferences in the modelling by imposing different growth rates and adjusting preferences for vehicles sizes and mode use.

Table 14: Growth rates for vehicle kilometres travelled by mode and vehicles class for different social and cultural preferences

Vehicle class	Expected growth rate with social and cultural preferences unchanged	Expected growth rate with social and cultural preferences supporting slower transport demand growth
Passenger road vehicles	1.2%	0.6%
Commercial road vehicles	3.0%	2.2%
Buses	2.3%	4.6%
Rail	1.2%	12.9%
Sea	0.0%	0.5%
Aviation	2.4%	1.6%

The second column of Table 14 shows the growth in transport demand by transport mode that we would have expected if their were no change in social and cultural preferences. In terms of non-road transport, the falling cost of air transport has seen significant growth in recent years and rail has kept pace with heavy road freight. However, sea transport has not grown at all in the last decade. The bulk of the increase in air travel is viewed as an income and wealth effect rather than substitution for transport that would have occurred via other modes.

As discussed above the growth in road passenger travel is linked to population growth whereas the growth in road commercial transport reflect growth in GDP. In terms of vehicle sizes we would expect there to be little change in the vehicle size shares shown in Figure 72 without some shift in social and cultural preferences.

Rising oil prices might be expected to change the mode choice in Australia by making mass forms of transport such as rail and buses more attractive. However, the econometric evidence suggests that travel mode choice is not price elastic (Table 15). Based on such evidence, even a very unlikely 100 percent increase in the cost of car travel would only lead to a less than 5 percent increase in bus or train travel. This data only represents the historically observed changes in demand for transport modes. It is possible that much larger changes could be observed in the future if price changes are much greater and more sustained than in the past and supported by additional measures such as non-road transport infrastructure development.

Table 15: Travel demand elasticity with respect to the fare or cost of trips in own or alternative modes of transport

Travel mode	Train	Bus	Car
Train	-0.186	0.019	0.181
Bus	0.016	-0.151	0.166
Car	0.046	0.036	-0.094

Source: Taplin et al. (1999, table 5, p. 228).

Within road transport, vehicle choice has been shifting. Many people will have noted the increasing popularity of Sports Utility Vehicles (SUVs). The recent oil price increases saw a shift to lighter vehicles. However that does not appear to be sustained. This was the case during the 1970-80s oil shock. From 1970 to 1980, new vehicles registered in the smaller medium sized car range increased from 14 to 26 percent.. Intermediate medium sized cars also increased from 15 to 30 percent of new registrations. At the same time the share of new registrations of large and larger medium size cars fell (Monash University Accident Research Centre, 1993). However, the trend levelled out and shares even reversed by a few percentage points when oil prices were still high, but coming off their peak during the 1980s. Some of the purchasing of lighter cars can also be accounted for by improvements in income at the time, which meant second cars were affordable. Recent oil price increases are around the same magnitude but our income has more than doubled since that time. This means we are more able to absorb costs and can not be expected to respond in the same way. We can also be expected to respond different to sustained and short term price changes

The third column of Table 14 shows the growth in transport demand by transport mode that we expect in response to sustained high oil prices and the introduction of emission trading. In terms of non-road transport, the reduction in the assumed rate of growth will lead to a 133 percent increase in rail kilometres relative to the case where there are no changes in social preferences. This is equivalent to 4 times the current level of passenger journeys by 2050. Aviation travel will be 39 percent less than under the case where there are no social and cultural preference changes. Sea transport will be 56 percent higher.

In terms of road transport, passenger and commercial transport will be 27 and 36 percent lower in 2050 respectively. It is also assumed that the share of light passenger and light commercial vehicles will increase its share to 50 and 30 percent respectively at the expense of the medium and heavy weight categories.

Price elasticity of demand

Price elasticities for demand have been assumed based on data available from the Transport Elasticities Database Online available at http://dynamic.dotars.gov.au/btre/tedb/index.cfm. For road transport these are generally in the range of -0.2. In ESM we assume that for large changes in price (more than 50 percent difference from current levels) the price elasticity for passenger vehicles more than doubles to around -0.4 to -0.7 depending on the vehicle size. Heavy vehicle owners are expected to have a higher elasticity because they have a greater exposure to non-fixed costs (e.g. fuel) in their total transport costs.

The price elasticity of demand for aviation if referring to the total cost of aviation is around -1 for all passengers. The elasticity is lower for business passengers at around -0.5 and higher for leisure passengers (between -1 and -2). Aviation fuel is only around 25-30% of total costs. Therefore the price elasticity of aviation transport demand in terms of fuel costs is around -0.25 to -0.3.

Sea and rail transport are currently assumed to be price inelastic. This is because in scenarios with rising costs of transport in road and aviation modes, rail and sea are typically assumed to benefit due to mode switching. The level of mode switching is imposed rather than calculated via an elasticity. As discussed above the econometric evidence does not support substantial mode switching in response to price changes. However, substantial mode change could be driven by very large price changes not yet observed in the historical record or by other non-price factors.

APPENDIX B - MODEL ASSUMPTIONS RELATING TO ELECTRICITY GENERATION

The assumptions in this section have be drawn substantially from Graham et. al (2008).

Technology performance and cost data

Table 16 shows key technology cost and performance assumptions for centralised generation (CG) plant that have been applied in modelling the base case scenario. Capital costs refer to the installed cost including the capital charges during construction period, royalty allowances, cost of land and site improvement or mine development and other owner's costs.

The volatility of generation markets can have a positive or negative effect on generation plant costs. For example, in the years during and following the Asian Economic Crisis, the costs of power plant, particularly gas-fired units, fell significantly as many potential buyers in Asia were forced out of the generation plant market. Currently it appears the market has moved in the opposite direction. A surge in demand for new power plants has occurred together with a period of strong demand growth for metals and other plant input materials (DOE/EIA, 2006).

Table 16: Technology cost and performance assumptions, 2010: centralised generation

	Installed Capital cost A$/kW	**Capacity factor**	**Thermal Efficiency**	**O&M cost A$/MWh**	**Fuel cost A$/MWh**	**Plant life years**
Brown coal pf	2050	0.87	0.31	6.0	5.8	50
Black coal pf	1850	0.80	0.40	6.6	9.0	50
Black coal IGCC	2450	0.80	0.41	8.0	8.8	50
Natural gas combined cycle	1200	0.80	0.49	7.8	22.0	25
Solar Thermal	3420	0.27	na	20.3	na	25
Wind	1925	0.29	na	7.9	na	25
Large Hydro	3010	0.20	na	28.5	na	100
Biomass	2975	0.55	0.26	6.0	20.8	30
Brown coal IGCC	2900	0.80	0.41	8.3	4.4	50
Brown coal CCS	3295	0.80	0.32	11.3	5.6	50
Black coal CCS	3215	0.80	0.33	11.0	10.8	50
Brown coal partial CCS	2555	0.80	0.37	11.3	4.9	50
Black coal partial CCS	2450	0.80	0.37	11.0	9.7	50
Gas peaking	700	0.20	0.20	23.5	54.0	25
Gas with CCS	1750	0.80	0.43	12.0	25.1	25
Nuclear	4175	0.80	0.34	12.8	7.9	50
Hot fractured rocks	5290	0.80	na	17.8	na	25

Notes:

Capture rate of 85% and 50% is assumed for CCS and partial CCS technologies, respectively.

The capital cost of nuclear power includes the cost of decommissioning the plant (it adds approximately $300/kW). This approach is mathematically equivalent to adding the decommissioning cost to the annual operating cost of the plant and so does not pre-empt any potential arrangements in Australia with regard to paying upfront versus making annual payment over the life of the plant.

Thermal efficiency refers to the ratio of useful energy output to non-renewable energy input based on gross calorific value (higher heating value). These ratios are only recorded if they use a fuel.

Capacity factors for renewables represent an average of the best available currently undeveloped sites across all States.

Fuel costs assume current cost of fuel. Fuel costs increase with time or volume consumed in the modelling

O&M costs include labour charges for regular operation and maintenance of plant equipment, cost of maintenance material, and labour charges associated with administration and support functions for plant operations.

The capital cost, O&M cost and thermal efficiency data for CG technologies are recent CSIRO estimates but are closely related to Wibberley *et al*. (2006). Fuel costs are derived from the primary cost of fuel that prevailed in the base-year, 2005. On average, across the States these are estimated to be: black coal ($1/GJ); brown coal ($0.5/GJ); natural gas ($3/GJ); biomass ($1.5/GJ); diesel ($15/GJ) and uranium ($0.75/GJ).

Table 17: Technology cost and performance assumptions, 2010: distributed generation

Technology	Installed Capital cost A$/kW	Capacity factor	O&M cost A$/MWh	Fuel cost A$/MWh	Energy Efficiency years	Plant life
Internal combustion diesel	920	0.30	45	120	0.45	15
Internal combustion natural gas	1260	0.30	50	57	0.28	15
Gas turbine	800	0.30	45	57	0.28	20
Gas micro turbine	1175	0.30	45	57	0.28	15
Gas CCGT (CHP)	1350	0.30	10	19	0.85	20
Biomass CHP	3125	0.30	10	10	0.55	20
Gas micro turbine CHP	1495	0.30	50	24	0.68	15
Gas reciprocating engine CHP	1375	0.30	55	22	0.75	15
Biomass	2150	0.30	10	19	0.28	20
Solar Photovoltaic	7275	0.20	2	na	na	20
Wind	3625	0.28	2	na	na	20
Biogas reciprocating engine	1265	0.30	50	neg	0.30	20
Fuel cell hydrogen	3130	0.50	70	72	0.50	20
Fuel cell natural gas	3130	0.50	70	22	0.50	20

Notes:

Compared to data for centralised generation, data for the distributed generation sector is generally poorer in quality. The data is from a wide variety of sources.

Capacity factor is generally assumed to be 30% unless specific information suggests otherwise. Where information is available, capacity factors differ slightly across States.

Energy efficiency refers to the ratio of useful energy output to non-renewable energy input based on gross calorific value (higher heating value). These ratios are only recorded if they use a fuel.

Fuel costs assume current cost of fuel. Fuel costs increase with time or volume consumed in the modelling

Treatment of technological change

There are several factors that impact upon projections of future costs of electricity generation technologies. The three factors which we have attempted to account for in our methodology are:

- Resource constraints or the quality of resources available;
- The volatility of generation plant markets; and
- Technological improvement or “learning”.

With regard to the third factor, it is broadly recognised that technological improvement has a close relationship with deployment. This observation was first made in the early part of last century during the study of industrial production of military aircraft (Wright, 1936). It was found that a reduction in costs of technologies can be observed as a fixed rate for each doubling of cumulative production. These relationships are often called experience or learning curves.

Experience or learning curves are applied at the world level so that costs decline as a function of each doubling of cumulative global capacity installed. The learning curve approach recognises that reductions in the cost of capital or plant are directly the result of learning that occurs through experience ("learning by doing") and economies of scale as a technology is adopted, rather than indirectly through the passing of time. A key implication of this approach is that cost changes can occur at any point in time so long as there has been a sufficient interval for capacity to be installed and the relevant economic or policy drivers are in place to kick-start adoption.

The historical learning rate for currently deployed electricity generation technologies has been comprehensively reported elsewhere (e.g., McDonald and Shrattenholzer, 2001). However, what we require for our purposes is the future learning rate. Future learning rates will change as technologies pass through various stages of their technological development. For example, a technology with a learning rate of 20 percent for each doubling of cumulative capacity in the last ten years may have a learning rate of only 10 percent in the next 20 years as it becomes more mature. As a result, setting a fixed learning rate now based on historical rates may overestimate future technological change.

To form estimates for future capital costs of our CG technologies, we used the following approach:

- Average learning rates for immature technologies of around 10-15 percent;
- Average learning rates for mature technologies of around 0-5 percent;
- A lower bound on technology costs equal to the cost of the current most dominant technology; and
- Maximum rate of change in five year period is 10 percent unless specific advice available that a breakthrough is occurring.

Based on this approach, the estimated time path of capital costs for our CG technology set is shown in Figure 75.

With regard to DG technologies, we employed estimates from a report commissioned by the UK Department of Industry (Energy Savings Trust, 2005). It uses a similar methodology to that described for CG technologies, but does not place limits on the maximum rate of change over a time period or impose lower bounds. The estimated time path of capital costs for our DG technology set is shown in Figure 76.

Figure 75: Estimated time path of installed capital costs for CG technologies

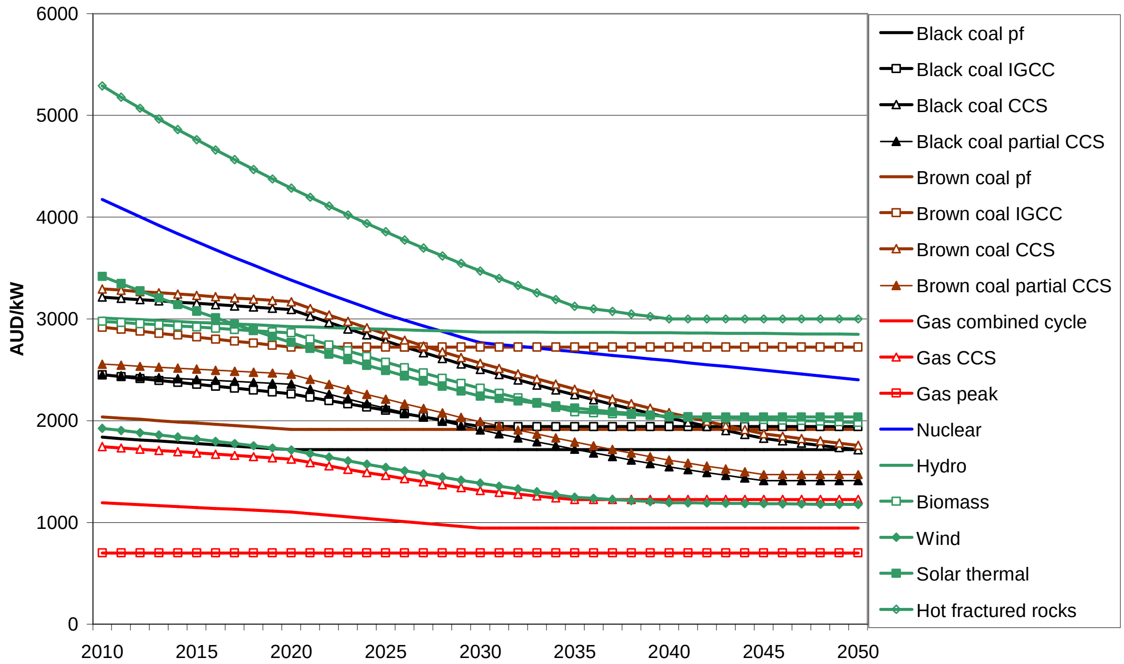
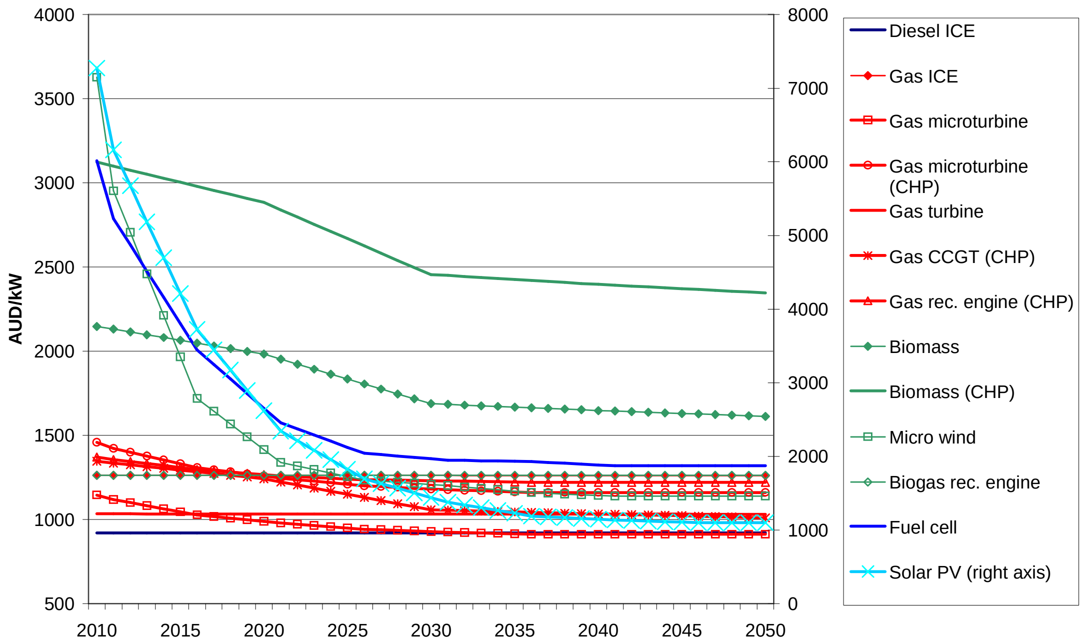


Figure 76: Estimated time path of installed capital costs for DG technologies

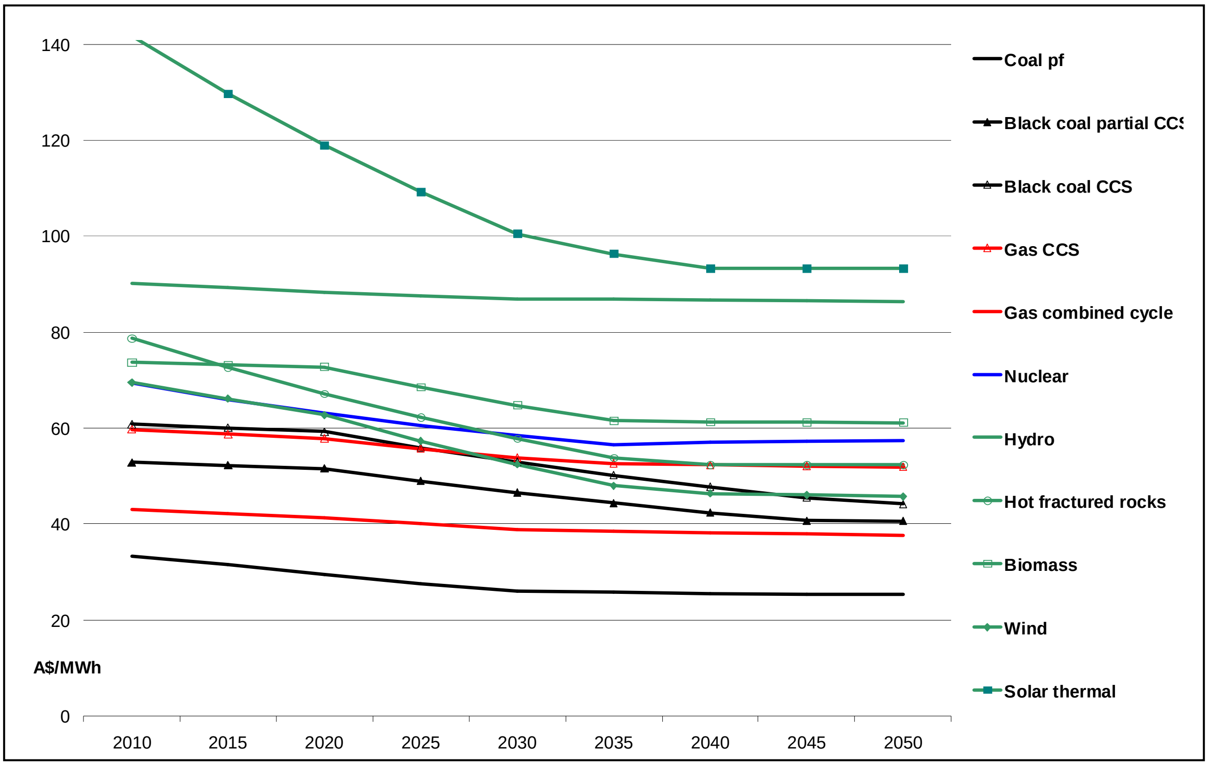


The abbreviations are as follows. ICE: internal combustion engine; CHP: combined heat and power; CCGT: combined cycle gas turbine; rec.: reciprocating; PV: photovoltaic

It is important to note that these capital costs are not the sole determinant of technological choice. For technologies based on natural gas, for example, the cost of fuel may be of greater importance. Also some high cost technologies such as hydro, solar thermal and gas peaking plant derive a significant portion of their revenue from the higher value peak market. The quality of the resource available to the power plant is also very important. For example, there is significant variance in the quality of wind sites available across Australia.

Figure 6 shows the indicative long run average cost of selected centralised generation technologies taking into account the capital costs above, operating costs, trend fossil fuel costs averaged across the relevant states and a constant quality of renewable energy resources. In ESM, we make allowances for changes in renewable resource quality and fossil fuels costs in each state depending on their rate of utilisation. As a result, the technology choices observed in the scenario analysis will not always match the implied competitive ranking shown in Figure 77.

Figure 77: Indicative time path of long run average costs for CG technologies



Electricity demand, economic growth and price responsiveness

Projections of future electricity demand by state are available from ABARE (see Cuevas-Cubria and Riwoe, 2006). ABARE's regular national projections relate only to business as usual scenarios. They are based on future projections of economic growth, improvements in energy efficiency and some efforts to identify near term energy intensive projects, such as those associated with alumina refineries. ABARE projects the average growth rate for Australia to 2030 to be around 1.9 percent, per annum.

Base case demand projections are adjusted downward for emission reduction scenarios to take into account:

- Lower economic growth as a result of internalising costs of CO_2 emissions into final goods and services consumed; and
- Lower energy required per unit of GDP due to structural change in the economy (energy intensive industries decline at the expense of less energy intensive industries) and greater uptake of energy

saving technologies and processes. Counter to this is the possible protection of carbon intensive export exposed industries which will reduce the amount of restructuring that might have taken place (Prime Ministerial Task Group on Emissions Trading, 2007).

The degree of change in GDP and energy efficiency is not calculated by the model but is adapted from the literature such as Energy Futures Forum (2006). The imposition of CO_2 prices generally reduces electricity demand growth to around 1.5 percent to 2030.

Demand growth is not entirely fixed because ESM assumes that consumers will respond negatively to electricity price rises and positively to electricity price decreases. As reported in Graham *et al*. (2005), price elasticities of demand for electricity in the literature generally range from -0.2 to -0.5. This means a 10 percent increase in prices would lead to a 2 to 5 percent decrease in electricity demand.

The price elasticity of demand for electricity can be expected to change over time. A useful way to consider this is to think of a household budget. For a person earning an after tax income of $25,000 and an annual electricity bill of $1,000, electricity represents 4% of their annual budget. By 2050, assuming a 2% per annum real increase in wages, their after tax real income will be approximately $60,000. On a constant price basis electricity now represents just 1.6% of the annual budget. As a result, the household's response to a given percentage change in this budget item is likely to be smaller than at present. If we also consider that price elasticity of demand estimates are based on data from the previous two decades then it is possible that present price elasticity estimates are already out of date in terms of reflecting household and other group's responses to price changes.

For this reason, in ESM it is assumed the price elasticity of demand is at the very bottom of the range in the literature at -0.2. Furthermore, this price elasticity only applies for large price changes (above 25%). For small price changes the price elasticity of demand is assumed to be -0.1. These are applied uniformly across all customers, except for industrial end-users.

Recent analysis in Australia has acknowledged that some industries may be particularly disadvantaged by the implementation of CO_2 pricing if the following three conditions apply: the industry is particularly emissions intensive; the industry is trade exposed; and this trade exposure is amplified by competition from countries that are not subject to emission caps under the Kyoto Protocol (Prime Ministerial Task Group on Emissions Trading, 2007; Saddler *et al*., 2006). As a default assumption, 15 percent of industrial electricity demand was assumed responsive to price changes.

Intermittency

Under the National Electricity Code (NEC), an intermittent generator is classified as: "a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability" (NECA, 2002: Chapter 10, p 27A).

An increased penetration of intermittent supply raises several issues in the Australian context. First, it may impair the accuracy of "demand" (scheduled generation) forecasts within the NEM. Second, it has implications for electrical system stability in maintaining power system frequency within defined limits through the dispatch of frequency control ancillary services (NEMMCO, 2003). Related to the above issues, is the increased need for spinning reserve to meet unexpected shortfalls in scheduled generation or increased fluctuations in frequency. To be reliable, such reserve would need to be provided by base-load fossil fuels (most likely gas), or non-intermittent renewable sources (e.g., biomass or hot fractured rocks).

A number of measures are being considered to overcome the problems posed by an increased proportion of intermittent generation in the NEM. The first measure is an improved spatial positioning of the intermittent technologies to reduce the volatility of their combined output. This measure relates to the observation that wind regimes experienced across a large power system are unlikely to be highly correlated (Archer and Jacobsen, 2003). Ideally, wind farms should be spread over different regions and not be permitted to bank up in single regions. Another measure is improvements in weather forecasting to reduce the uncertainty in the dispatch interval. Reliable wind power forecasting has the potential to considerably improve the cost-effectiveness of wind farms connected to the grid by reducing dispatch and commitment errors, reducing the need for spinning reserve (Outhred, 2003).

Recognising the potential difficulty in managing intermittency associated with wind and solar energy, the contribution of large intermittent technologies (>30MW) was constrained to not exceed 20 percent of total system generation capacity by 2020 and then linearly increased to a limit of 30 percent by 2050 to recognise some improvement in cost effective storage availability. There is some uncertainty about whether this constraint is at the right level. Wind is already at a high penetration in overseas countries (e.g., Denmark and Germany) and South Australia, suggesting the constraint may be too low. The highly probable future development of cost-effective electricity or energy storage could push shares above 30 percent if is progresses faster than expected.

Within ESM it is assumed that the intermittent constraint applies to centralised and not DG on the presumption that DG will be sufficiently geographically dispersed and at smaller scale than large (>30MW) intermittent power stations.

Geological storage of CO_2

In determining the potential for the geological storage of CO_2, the GEODISC program assessed over 100 potential environmentally sustainable sites for CO_2 injection (ESSCIs) by applying a deterministic risk assessment based on five factors: storage capacity; injectivity potential; site details; containment; and natural resources. Utilising this approach, Australia has a CO_2 storage potential in excess of 1600 years of current annual total net emissions. However, this estimate does not account for various factors such as source to sink matching. According to Bradshaw *et al*. (2004), if preferences due to source to sink matching are incorporated, Australia may have the potential to store a maximum of 25 per cent of current annual total net emissions, or approximately 100 to 115Mt CO_2 per year.

More recent analysis for Victoria assessed the cost and potential for the geological storage of CO_2 in the offshore Gippsland basin from the Latrobe Valley (Hooper *et al*., 2005). The study determined that up to 2000 Mt may be stored over a forty year period (50Mt per year) and estimated the cost of CO_2 transport and storage via a 200km pipeline at $10.50/t. For Western Australia, analysis by Allinson *et al*. (2006) identified three potential storage sites in the Perth basin capable of storing 25Mt per year for twenty five years with the cost of CO_2 transport and storage ranging from $10 to $15/t.

Given the lack of detailed information which would facilitate the construction of CO_2 transport and storage cost curves for all States, a disposal cost of $10/t has been applied to any CO_2 stored. No cap on the amount of CO_2 that can be sequestered per year has been applied due to the modelling of a CCS infeasible sensitivity case in this report.

Air (dry) cooling

The occurrence of the worst drought conditions in eastern Australia since Federation has heightened debate about the efficient allocation of scarce water resources among competing end-users. This has been manifested in the widespread use of water restrictions, debate over desalination and stormwater harvesting in major cities, and discussions between the States and Commonwealth over administration of the Murray-Darling Basin.

The situation in south-east Queensland has forced the State Government to cut the water usage of Tarong North and Swanbank coal-fired power stations by 40 and 20 percent, respectively. Given that electricity supply in Australia is currently dominated by coal-fired generation (approximately 81 percent) this has raised the possibility of reduced water supply to power stations in other jurisdictions.

The default is to assume that new base load fossil fuel power stations installed after 2007 will be dry-cooled. We do not assume that existing water-cooled base load fossil fuel power stations will be converted to air-cooled plant.

The effect of air cooling is a subtraction of approximately 2 percent in thermal efficiency relative to a water cooled plant and an additional $100/kW in installed capital cost.

Greenhouse gas emission factors

Direct and indirect CO_2e emissions (i.e., CO_2 plus equivalent emissions from other greenhouse gases such as methane (CH_4) and nitrous oxides (N_xO) from direct combustion and indirect upstream losses from transport and conversion processes) from fuels were calculated as shown in Table 18 below.

Table 18: Full fuel cycle GHG emission factors for electricity generation fuels

	Direct emissions (gCO_2e/MJ)	**Indirect emissions** (gCO_2e/MJ)	**Total emissions** (gCO_2e/MJ)
Black coal	89.92	5.37	95.29
Brown coal	93.5	0.1	93.6
Natural gas	51.6	11.3	62.9
Diesel	67.5	14.1	81.6
Biomass	n.a.	n.a.	n.a.
Hydrogen from renewables	n.a.	n.a.	n.a.
Uranium	0	-	-

Notes:
- small
n.a. means not applicable because the convention is that when the fuel is renewable only indirect emissions are counted. Alternatively direct emissions for biomass are 94 gCO_2e/MJ
Emissions for hydrogen, if produced from natural gas, are 83 gCO_2e/MJ with all emissions occurring indirectly.
Source: *Australian Greenhouse Office (2002a and 2002b*)

Default electricity policy settings

Nuclear power

Nuclear power is not supported by the current federal government and is also legislatively prevented from being taken up in most States. The default assumption is to not allow nuclear power to be available as a technology. If for sensitivity purposes it is allowed then its uptake is still restricted before 2035. The justification for this assumption is the length of construction of a nuclear power plant (around ten years), the time needed to achieve bi-partisan political support and additional time required to complete the accompanying regulatory and legislative processes.

Mandatory Renewable Energy Target (MRET)

MRET seeks to increase the contribution of renewable energy sources in Australia's electricity mix by 9,500 GWh per year by 2010. The recent change in government means that this will now increase to 45,000 GWh by 2020.

Within ESM, MRET is modelled as a constraint on sent out electricity by ensuring that the amount of centralised and distributed renewable generation is not less than the minimum amounts set out in the legislation for each year to 2020.

Queensland 13 percent gas target

On 24 May 2000, the Queensland Government announced the *Queensland Energy Policy – A Cleaner Energy Strategy*, with the key objectives of the policy being to diversify its energy mix, facilitate the supply and use of natural gas in Queensland, especially in electricity generation, and reduce growth in greenhouse gas emissions. A key component of the energy policy is the State's 13 percent gas scheme, which requires electricity retailers and other liable parties to source at least 13 percent of their electricity from natural gas-fired generation. The scheme commenced on 1 January 2005 and will remain in place until 31 December 2019.

This scheme is implemented in the model in an approximate manner, requiring the share of natural gas-fired electricity consumed in Queensland to increase to 13 per cent by 2010. This modification reflects evidence that the amount of gas-fired generation was below target in 2005.

NSW Greenhouse Gas Abatement Scheme (GGAS)

In January 2002, the NSW Government released a Benchmarks Position Paper that set the aims and methodology for the Greenhouse Gas Abatement Scheme (GGAS). The scheme came into effect from 1 January 2003. From that time, NSW electricity retailers and some other parties ("benchmark participants") must meet mandatory targets for abating the emission of greenhouse gases from electricity production and use, up until 2012.

The State-wide benchmark is to reduce greenhouse gas emissions to 7.27 tonnes of carbon dioxide equivalent per capita by 2007, which is 5 percent below the baseline year of 1989-90. The targets for abatement are higher each year from 2003 to 2007, and then the benchmark level must be maintained until 2012.

To reduce the average emissions of greenhouse gases, participants will purchase and surrender abatement certificates to the Independent Pricing and Regulatory Tribunal (IPART). Abatement certificates can be created from the following activities:

- Reduction in the greenhouse intensity of electricity generation;
- Activities that result in reduced consumption of electricity ("demand side abatement");
- The capture of carbon from the atmosphere in forests, referred to as CO_2 sequestration; and
- Activities carried out by elective participants that reduce on-site emissions not directly related to electricity consumption.

Similar to MRET, GGAS is modelled as a constraint that requires total emissions from NSW electricity generation to be less than or equal to the product of per person emissions and state population.

As mentioned above, currently the benchmark scheme ends in 2012. Rather than extending the scheme beyond 2012, the NSW Government has stated the preference for the introduction of a single national trading scheme. In the modelling of emission reduction scenarios, NGACs is not extended beyond 2012 due to the commencement of emissions trading.

State Renewable Energy Targets

It is assumed that the state renewable energy targets are replaced by the expanded MRET.

Photovoltaic Rebate Program (PVRP)

There are also direct subsidies for photovoltaics via the Photovoltaic Rebate Programme (PVRP). Current legislation has the subsidy at $3500-4000/kW for a 1kW household system. However, it has recently been announced that the Government will provide $150 million over five years ($26 million in 2007-08 and $31 million per annum from 2008-09 to 2011-12) to extend and expand the Photovoltaic Rebate Programme, which provides rebates for the installation of eligible photovoltaic systems (Treasury, 2007). Under the expansion, existing household rebate rates and caps will be doubled from current levels. Rebates for households will be increased to up to $8,000/kW for households (equivalent to $340/MWh subsidy). It also includes grants of up to $12,000 to support installations in schools and other community education buildings.

ESM models the absolute amount of funds available for solar photovoltaic subsidies and assumes that whilst the subsidy per household may fall over time a technology costs fall, the general level of funding for the PVRP will remain unchanged.

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