K The United States' electricity generation sector

The Commission estimated subsidy equivalents, abatement and implicit abatement subsidies for several US policies, including the Regional Greenhouse Gas Initiative, state-based Renewable Portfolio Standards, the Renewable Electricity Production Tax Credit and Section 1603 Treasury Grants. Four Californian capital subsidies (the Californian Solar Initiative, New Solar Homes Partnership, Self-Generation Incentive Program and the Emerging Renewables Program) were also examined. These Californian schemes have been included as California is responsible for approximately 70 per cent of US solar generation, which is not included in the federal-level policies analysed.

Several other policies were considered, but not included in the estimates (section K.15). In particular, the Commission's analysis of state-based schemes was restricted due to constraints of time and data availability. For some federal schemes, the Commission was not able to obtain the data necessary to estimate abatement.

Where data permitted, subsidy equivalents and abatement were estimated for the 2010 calendar year. However, for many schemes, the year of analysis was 2009. Subsidy equivalents and implicit abatement subsidies are reported in both US and Australian dollars, with currency conversion rates based on the average exchange rate for 2010 (A$/US$ = 1.087). A GDP deflator of 1.01 was used to convert 2009 values into 2010 values.

For some of the policies that were analysed in detail, the Commission carried out sensitivity analysis. The results of the sensitivity analysis are reported in comparison to the Commission's 'central' estimate. The central estimate is based on the set of assumptions that the Commission considers to be most consistent with its approach to estimating subsidy equivalents and abatement.

References in this appendix to Vivid Economics refer to unpublished data supplied to the Productivity Commission by that contractor. The relevant data are provided on the Commission's website, where there are no commercial-in-confidence restrictions.

K.1 Electricity generation in the United States

This section outlines some of the key features of the US electricity market, followed by some key statistics for the US electricity generation sector.

The structure of the US electricity market

There are three loosely-connected electricity grids in the United States (the Western Interconnected System, the Eastern Interconnected System, and the Texas Interconnected System)[1] and ten electricity markets (box K.1). The US electricity system is also integrated with Canada and, to a lesser extent, Mexico (table K.1).

Table K.1 **Imports and exports of electricity**
United States, 2009

	Imports	*Exports*
	TWh	TWh
Canada	51	17
Mexico	1	0.6

Source: EIA (US) (2011g).

Traditionally, US electricity markets were operated by vertically-integrated utilities that owned and operated the transmission networks. Markets were formed via agreements between the utilities (for example, the PJM Interconnection was formed by an agreement between three utilities in 1927, and was traditionally operated by one of these utilities (PJM 2011)).

Since the late 1990s, many of the participants in these markets have formed an Independent System Operator (ISO) or a Regional Transmission Organisation (RTO). Seven markets (California, Midwest, New England, New York, the PJM, the Southwest Power Pool (SPP) and Texas) now have an ISO or RTO. ISOs and RTOs operate the transmission networks and coordinate competitive wholesale markets, with electricity provided via either long-term contracts or short-term (day ahead) markets. The equilibrium price is generally determined by the bid of the marginal generator (Linn 2011).

In markets without an RTO or ISO, vertically-integrated utilities operate the transmission networks and make investment decisions subject to the approval of the

1 There are a total of eight 'ties' between the three grids, which permit limited electricity transfers between the grids (Kaplan 2010).

state regulator. Similarly to a wholesale market, electricity from generators in these markets is dispatched in order of increasing cost (Linn 2011).

Box K.1 US electricity markets

There are ten US electricity markets operating across the three electricity grids. Peak demand data is shown for the most recent year available.

Western Interconnection

- California — covering most of California (summer peak demand — 46 GW (2009))
- Northwest — covering most of Washington, Oregon, Idaho, Utah, Nevada, Montana, Wyoming and part of California (summer peak demand — 44 GW (2009))
- Southwest — covering most of Arizona, New Mexico and Colorado, and parts of Nevada, Wyoming and South Dakota (peak demand — 45 GW (2005))

Eastern Interconnection

- Midwest — covering most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana and Michigan, and parts of Montana, Missouri, Kentucky and Ohio (summer peak demand — 116 GW (2006))
- New England — covering Connecticut, Massachusetts, New Hampshire, Rhode Island and Vermont (summer peak demand — 25 GW (2009))
- New York (summer peak demand — 30 GW (2009))
- PJM Interconnection — covering most of Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia, and parts of Indiana, Illinois, Kentucky, Michigan, North Carolina and Tennessee (summer peak demand — 127 GW (2009))
- Southeast — covering most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Tennessee, North Carolina, South Carolina and parts of Missouri, Texas and Kentucky (summer peak demand — 195 GW (2009))
- Southwest Power Pool (SPP) — covering most of Kansas, Oklahoma and Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas (summer peak demand — 43 GW (2008))

Texas Interconnection

- Texas — covering most of Texas (summer peak demand — 63 GW (2009)).

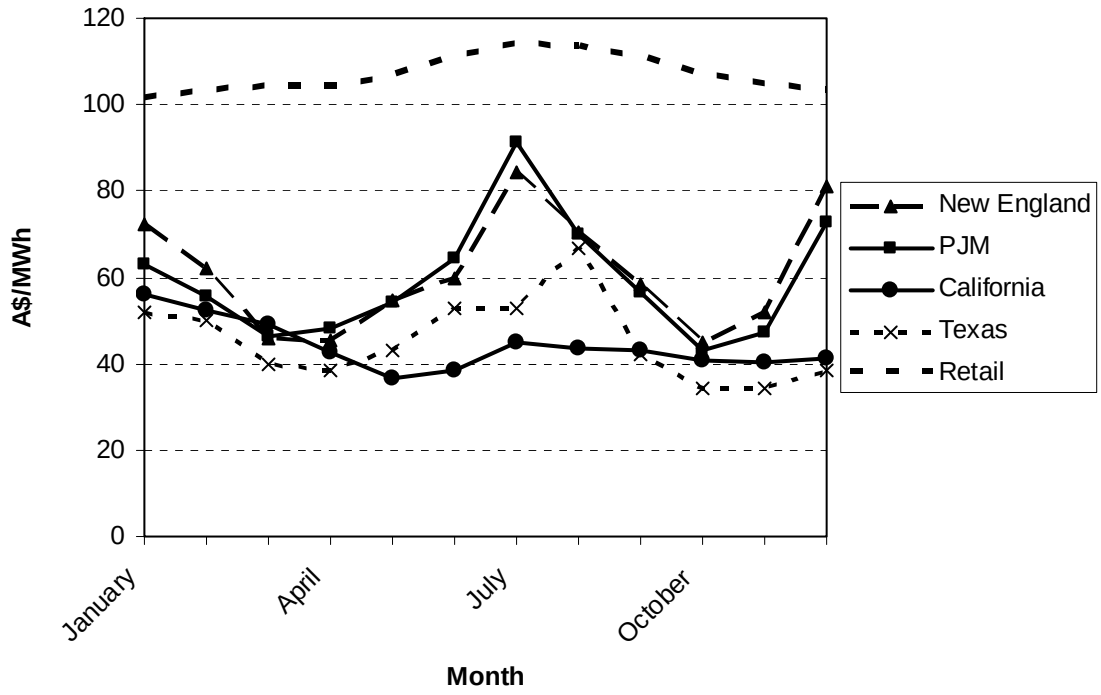
Source: FERC (2011).

Key statistics

Electricity prices

Wholesale prices in the United States vary across each market. Across four markets selected by the Commission, the average wholesale price in 2010 varied from US$41/MWh (A$44) in California to US$56/MWh (A$61) in New England) (figure K.1). The average retail price across all US markets in 2010 was approximately US$99/MWh (A$107).

Figure K.1 **Wholesale and retail electricity prices[a]**
United States, 2010



a Data for New England, PJM, California and Texas are wholesale prices based on unweighted average daily prices from a selected exchange in each market. Retail is the average US retail price.

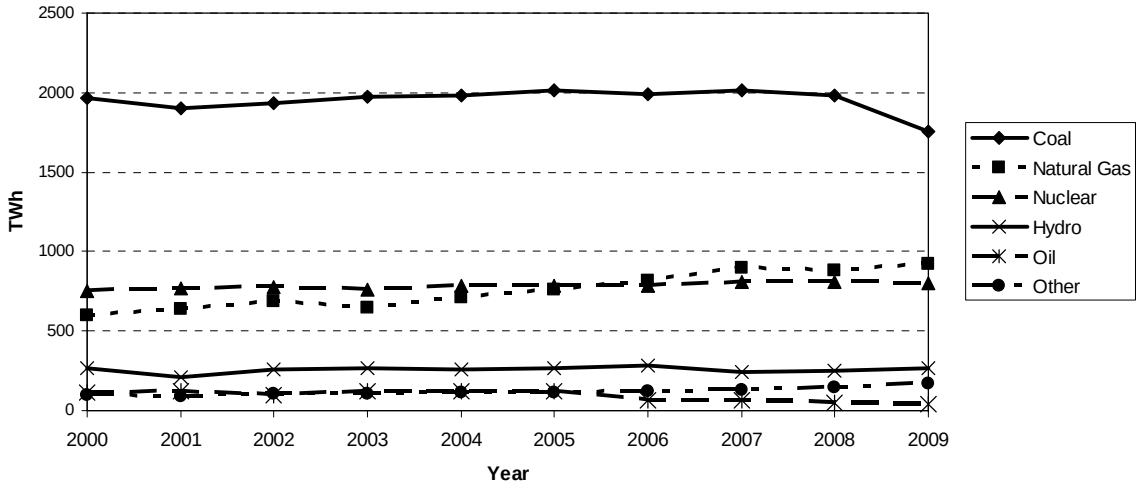
Sources: EIA (US) (2011e 2011o).

Electricity generation

The US electricity generation sector is predominantly a mix of coal, natural gas and nuclear (figure K.2). Renewable energy sources are currently a small but increasing component of the US generation mix. The primary source of non-hydro renewable energy used in electricity generation in the United States in 2009 was wind

(table K.2). Biomass and geothermal were also major sources of renewable electricity. Total generation in the US in 2009 was around 3950 TWh (EIA (US) 2010e).

Figure K.2 **Electricity generation by source**
United States, 2000–2009



a 'Other' predominantly consists of renewable electricity.

Source: EIA (US) (2011m).

Table K.2 **Non-hydro renewable energy sources**
United States, 2009

Renewable energy source	*Generation*
	GWh
Wind	73 886
Wood and wood derived fuels	35 596
Other biomass	18 443
Geothermal	15 009
Solar thermal and photovoltaic	891

Source: EIA (US) (2011m).

Greenhouse gas emissions

In 2009, the US electricity generation sector emitted 2270 Mt CO_2. This was lower than the peak of 2547 Mt CO_2 in 2007 (EIA (US) 2011h). In 2008, 81 per cent of electricity sector emissions were from coal-fired generation, 17 per cent were from natural gas, and the remaining 2 per cent were from other sources such as oil.

K.2 Abatement

Abatement in the United States was estimated using counterfactual emissions intensities for each electricity market. The counterfactual emissions intensities used were based on data provided by Vivid Economics (2011), which are in turn based on annual reports that each grid's operator makes to the Federal Energy Regulatory Commission. In most cases, the marginal generator (the generator that is next in the dispatch order) varies over the course of the year (for example, sometimes coal is the marginal energy source and sometimes gas is). Where this is the case, the grid marginal emissions intensity is estimated as an average of the emissions intensities of the marginal sources, weighted according to the proportion of time that each is marginal. These emissions intensities range from 0.406 t CO_2/MWh for California, to 0.908 t CO_2/MWh for the Midwest (table K.3).

Table K.3 **Grid marginal emissions intensities**
United States

Grid	*Marginal source*	*Marginal emissions intensity*
		t CO_2/MWh
California	Gas	0.406
Midwest	Coal (73 per cent) and gas (27 per cent)	0.908
New England	Gas (67 per cent), coal (18 per cent) and hydro pumped storage (15 per cent)	0.600
New York	Gas	0.597
PJM	Coal (80 per cent) and gas (20 per cent)	0.792
SPP	Coal (62 per cent) and gas (38 per cent)	0.795
Texas	Gas (73 per cent), coal (22 per cent) and wind (5 per cent)	0.600
Northwest	Gas	0.473
Southwest	Gas	0.468
Southeast	Coal and Gas[a]	0.770

a For the Southeast grid, proportions of the time each source was the marginal generator were not available, so it was assumed that each source is the marginal generator 50 per cent of the time.

Source: Vivid Economics 2011.

K.3 Policy overlaps

The Commission estimated the subsidy equivalent and abatement attributable to: state-based Renewable Portfolio Standards; the federal Renewable Electricity Production Tax Credit; Section 1603 Treasury Grants (federal); and four Californian capital subsidies (the Californian Solar Initiative, New Solar Homes Partnership, Self-Generation Incentive Program and the Emerging Renewables Program).

Renewable generators subsidised by the state-based Renewable Portfolio Standards are also eligible for subsidies under the Renewable Electricity Production Tax Credit or the Treasury Grants. Hence, these programs are considered to overlap completely. For this reason, the Commission has estimated:

- the abatement attributable to the Renewable Portfolio Standards and the two federal schemes in aggregate
- the combined implicit abatement subsidy attributable to these policies.

In estimating abatement from the state-based Renewable Portfolio Standards and the two federal level programs, the Commission has not made an assumption as to which of these policies is the 'binding' policy. Rather, it was assumed that the three programs in combination provided incentives for the development of eligible renewable energy generation. This is discussed further in section K.8.

The federal schemes do not cover solar photovoltaic (PV). For this reason, the Californian capital subsidies were assumed to not overlap with the federal schemes. Therefore, the Commission has separately estimated the abatement attributable to the set of Californian capital subsidies.

K.4 The Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a state-based cap-and-trade emissions trading scheme covering the electricity sectors of 10 US states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont). In 2009, these states accounted for approximately 9 per cent of US electricity generation. The scheme commenced in 2009, and aims to reduce CO_2 emissions from these ten electricity sectors by 10 per cent by 2018 relative to 2009 levels.

Generators larger than 25 MW in the participating states must purchase an allowance for every US (short) ton of CO_2 emissions (one short ton = 0.907 metric tonnes). These allowances must be surrendered every three years (the first compliance period ends at the end of 2011). Generators can use permits issued by any of the ten states for compliance. Quarterly auctions are held to distribute allowances.

The cap has been set to initially stabilise emissions in the participating states at 188 million US (short) tons. The cap will remain at this level from 2009 to 2014, before declining by 2.5 per cent per year until 2018. It appears that this cap is not binding, and therefore probably not leading to any reduction in emissions. The New York State Energy Research and Development Authority (NYSERDA) stated:

> CO_2 emissions in the RGGI region have declined from approximately 184.4 million [US (short)] tons in 2005 to 123.7 million [US (short)] tons in 2009, or 33 percent. (NYSERDA 2010b, p. 3)

NYSERDA identified three reasons why emissions fell, lower demand for electricity, increased use of gas in place of coal (due to relatively low gas prices), and changes in the available capacity.

The assertion that the cap is not binding is supported by the price of permits in the scheme. The auction reserve price (effectively a minimum permit price) for RGGI permits was set at US$1.86 (A$2.05) per US (short) ton in 2010 (equivalent to US$2.05 per (metric) tonne CO_2 (A$2.3)). For much of 2010, the permit price was very close to this level — trading from US$2.28 per (metric) tonne CO_2 (A$2.50) in March, to US$2.07 per (metric) tonne CO_2 (A$2.30) in June, and falling to the reserve price thereafter (Potomac Economics 2011).

The Commission's analysis of supply-side abatement due to emissions trading schemes focuses on fuel switching, such as the switch from coal to gas in the United Kingdom and Germany. At the 2010 permit price, the Commission considers it unlikely that much, if any, fuel switching is occurring due to the RGGI (box K.2). There may be a small increase in electricity prices, and thus some demand-side abatement (considered in section 4.4). However, for the supply-side analysis, the Commission estimated that the subsidy equivalent and abatement arising from the RGGI is zero. This is consistent with Linn (2011), who stated that:

> The RGGI permit price has been close to the minimum bid since mid 2010 … This implies that abatement because of the cap is very close to zero. (Linn 2011, p. 16).

As the RGGI cap begins to tighten, it is likely that the permit price will rise, and this may lead to some fuel switching and supply-side abatement within the electricity sector of the relevant states.

The United States has another state-based emissions trading scheme that is scheduled to begin in 2012 — the Western Climate Initiative (WCI). This is discussed further in section K.15.

Box K.2 **Potential for fuel switching in the RGGI — New York**

The following stylised example highlights the potential for a coal-gas switch due to the Regional Greenhouse Gas Initiative in the state of New York.

According to the EIA (US) (2011b, 2011c), in the state of New York coal cost US$3.13 per million Btu and natural gas cost US$7.49 per million Btu in January 2011. On average in the United States in 2009, 10 378 Btu of coal was required per kWh of electricity, and 8160 Btu of natural gas was required per kWh (EIA (US) 2011g).

This implies that the fuel cost of coal generation was approximately US$32.48/MWh, and the fuel cost of natural gas generation was approximately US$61.12/MWh. Given that fuel costs generally make up a large proportion of variable costs, and given the relative emissions intensities of coal and gas (generally around 0.4t/MWh for Combined Cycle Gas Turbines, and around 0.9t/MWh for black coal generation), this implies that a RGGI permit price of around US$60/t CO_2-e would be required before there would be a large short-run switch from coal to gas in New York. (Note that a lower carbon price could potentially result in a long-run change in investment decisions, however this is not considered here.)

Sources: EIA (US) (2011b, 2011c, 2011g).

K.5 Renewable Electricity Production Tax Credits

The Renewable Electricity Production Tax Credit (PTC) was initially introduced in 1992 as a per kWh tax credit for electricity generated from eligible renewable sources. It is provided to renewable energy generation in the commercial, industrial and agricultural sectors that on-sell electricity to an unrelated party. The PTC has expired twice since its introduction, once at the end of 2001 (renewed in March 2002) and again at the end of 2003 (renewed in October 2004). During this time, solar was eligible for the PTC for a period of one year. However, in general the PTC is not available for solar.

The current rate of the PTC is US 1.1 cents or US 2.2 cents per kWh and is generally available for the first 10 years of operation of eligible renewable generators.[2] Renewable energy generators eligible for the US 2.2 cent rate are wind, closed-loop biomass, geothermal, and solar. Renewable generators eligible for the US 1.1 cent rate are open-loop biomass, small hydro, landfill, waste, wave and tidal (IRS (US) 2010b).

2 With the exception of open loop biomass, geothermal, small hydro, landfill gas and municipal solid waste placed in service after October 2004, which are eligible for the credit for a period of five years.

Estimating the subsidy equivalent

The Commission's approach to estimating the subsidy equivalent of production tax incentives is analogous to the approach used for renewable energy target schemes and feed-in tariffs.

In the case of the PTC, the subsidy equivalent is equal to the value of the production tax credit per MWh (US$11 or US$22/MWh) multiplied by the amount of generation receiving the production tax credit in 2010 — this is also the value of the foregone tax revenue ('tax expenditure') to the US Government.

The Commission obtained a number of US Government estimates of the value of the PTC over the past several years. However, none of these estimates identified the amount or source of renewable electricity generation that received the PTC. Therefore, the Commission has used data from the Energy Information Administration (US) (2011m, 2011n) to estimate the total renewable electricity generation eligible for the PTC in 2009 (the most recent year for which data were available) and then multiplied this figure by the rate of the PTC in 2010 to estimate the subsidy equivalent in 2010. The Commission used this approach as it provided a consistent method for estimating abatement from the PTC.

Table K.4 shows the Commission's estimate of the amount of renewable electricity eligible for the PTC in 2009 — 75 TWh. Multiplying this figure by rate of the tax credit in 2010 (US$11 or US$22/MWh) provides an upper bound estimate of the value of the PTC (the subsidy equivalent) in 2010 of US$1.6 billion (A$1.7 billion).

Table K.4 **Estimating the value of the PTC**
United States, 2010

	Estimate of eligible generation (TWh)[a]	*Tax credit*	*Estimated value of tax credit*
	TWh	2009 US$/MWh	US$ m
Wind	66.6	22	1 466
Geothermal	1.3	22	28
Closed-loop biomass[b]	1.6	11	18
Hydro	1.7	11	19
Landfill	3.7	11	40
Municipal waste	0.1	11	0.7
Solar	0.0	22	–
Total (2010 US$)	**74.9**	**..**	**1 571**
Total (2010 A$)			**1 708**

a Data on eligible generation estimated by Vivid Economics using data from EIA 'Form 860' and EIA 'Form 923' (EIA (US) 2011i, 2011j). Electricity generators that elected to take the Treasury Grant in 2009 have been excluded from the estimate using the '1603 Grant' database from the US Treasury Department (2011b). **b** Open-loop biomass is granted a tax credit of US$22/MWh. There did not appear to be any eligible open-loop biomass in 2009. .. Not applicable – Nil or rounded to zero.

Sources: Vivid Economics, Productivity Commission estimates.

The Commission considers that using the 2009 generation estimates and the 2010 PTC rates provides a reasonable proxy for the value of the PTC in 2010, as it can be assumed that the majority of operators receiving the PTC in 2009 would also be receiving the PTC in 2010 — with the exception of those that may have shut down or reached the 5 or 10 year eligibility threshold for the PTC.

However, there are two factors that may affect the Commission's estimate for 2010. First, the estimate does not include eligible renewable generators constructed in 2010 that elected to take the PTC rather than the Treasury Grant or the ITC. However, the Commission considers that this is not likely to have had a significant effect on the estimates as:

- in 2009, when the cash grant was introduced, around two-thirds of wind projects elected to take the Treasury Grant (Linn 2011)
- the value of Treasury Grants for new wind in 2010 was large (around US$ 3.5 billion), which makes up the largest component of the Treasury Grants (around 90 per cent).

This led the Commission to assume that a large proportion of new wind projects in 2010 may also have elected to take the Treasury Grant in lieu of the PTC.

Second, not all eligible renewable electricity generation companies would have been eligible for the full PTC in 2009. In particular, the PTC is reduced for projects that receive other federal tax credits, grants, tax-exempt financing or subsidised energy financing (DSIRE 2011).

K.6 Treasury Grants

The US Federal Government enacted the American Recovery and Reinvestment Act of 2009 (US) (ARRA) in February 2009 as an economic stimulus package following the 2008 global financial crisis. The package included a number of measures aimed at stimulating economic activity and investment, one of which was Section 1603 — the Renewable Energy Grant program (the 'Treasury Grant'). The Treasury Grant provides a cash grant of either 30 per cent or 10 per cent of the capital costs of a number of renewable energy sources in the commercial, industrial and agricultural sectors.

The 30 per cent rate applies to fuel cells, solar, wind, biomass, geothermal (other than geothermal heat pumps), landfill, municipal waste, hydro, and marine-related electricity production. The 10 per cent rate applies to geothermal heat pumps, microturbines and combined heat and power (CHP).

The Treasury Grant is only available to tax-paying entities and can be taken in lieu of other Federal tax incentives (the Renewable Energy Investment Tax Credit (ITC) or the Renewable Energy Production Tax Credit (PTC)). Grants are available for renewable energy generators placed in operation in 2009, 2010 and 2011 (or afterwards if construction began before the end of 2011) after which time the grant is expected to cease. Grants are paid after the renewable electricity generator is placed in operation (US Treasury Department 2011a).

Estimating the subsidy equivalent

The Treasury Grant is provided as an upfront cash payment. Therefore, the Commission has estimated the subsidy equivalent of the program by annualising the total value of grants paid over the period 2009 and 2010. This is consistent with the approach used for other capital subsidies.

Data from the US Treasury Department (2011b) indicated that the total value of grants paid to eligible renewable electricity generators over 2009 and 2010 was US$5.7 billion (A$6.2 billion) in real 2010 values (table K.5).

Table K.5 **Treasury Grants, value of grants**[a]

United States, 2009, 2010

	2009	*2010*	*Total*
	US$m	US$m	US$m
Wind	1 380	3 477	4 857
Solar	27	374	401
Combined heat and power	0	5	5
Fuel cells	2	3	4
Small wind	0	49	49
Landfill gas	3	7	10
Biomass	71	44	115
Geothermal	119	141	261
Hydro	4	3	7
Marine	0	0	0
Microturbine	0	0	0
Waste	0	3	3
Total (US$)	1 607	4 105	5 712
Total (2010 US$)	**1 622**	**4 105**	**5 727**
Total (2010 A$)	**1 764**	**4 462**	**6 226**

a Grant data are provided for electricity generation only and exclude solar thermal and geothermal used for heat as these are outside the scope of the Commission's analysis.

Sources: US Treasury Department (2011b), Productivity Commission estimates.

The estimated annualised value (subsidy equivalent) of these grants in 2010 was US$541 million (A$588 million) — based on an interest rate of 7 per cent and an average economic life of renewable electricity assets of 20 years.

Estimating annual generation

The US Treasury has estimated the total annual generation for 2011 from assets supported by the Treasury Grants program for the period 2009 to 2011 (table K.6).

Using these data, and data on the value of grants to renewable energy producers in 2009 and 2010, the Commission estimated the annual generation from renewable energy in 2009 and 2010. The process was, for each type of renewable, to estimate the proportion of total expenditure over the period February 2009 to February 2011 that was paid out in 2009 and 2010. This was done by:

1. dividing the total value of grants paid in 2009 and 2010 by the total value of grants paid for renewable electricity over the period 2009 to February 2011
2. these proportions were then applied to US Treasury data on total annual generation from the Treasury Grants program over the period 2009 to end February 2011 to estimate annual renewable electricity generation by source in 2010.

Using this approach, the Commission estimated annual electricity generation from the Treasury Grants program in 2010 of 22.3 TWh, the large majority of which was wind (19.9 TWh) (table K.6).

Sensitivity analysis

The Commission carried out sensitivity analysis using discount rate values of 3 and 11 per cent. Using these values, the subsidy equivalent of the Treasury Grants program is estimated to be between US$385 million (A$418 million) and US$719 million (A$782 million) in 2010 respectively.

Table K.6 **Estimated renewable generation attributable to the Treasury Grants program**

United States, 2010

	Total value of grants (Jan 2009 to Feb 2011)[a]	*Total value of grants (2009 to 2010)*[a]	*Proportion of grants paid in 2009 and 2010*	*Total annual generation (2011)*	*Estimate of annual generation in 2010*[b]
	US$m	US$m	%	GWh	GWh
Biomass	116	115	99.5	855	851
Geothermal	268	267	99.7	805	783
Solar	757	405	53.4	715	379
Wind	5 246	4 906	93.5	21 302	19 921
Other[c]	54	29	53.6	756	405
Total	**6 441**	**5 722**	**88.8**	**24 433**	**22 339**

[a] The total value of grants paid includes all grants paid to renewable energy generation (including geothermal and solar thermal used for heating purposes). Hence, figures for the total value of grants (2009 to 2010) in table K.6 are slightly different to those provided in table K.5. [b] Annual generation for 2010 was estimated by applying the proportion of grants paid in 2009 and 2010 to the data on generation from generators installed over the period January 2009 to end February 2011. However, the Commission was unable to determine how much generation from geothermal and solar was for heat related purposes. Therefore, the proportion of total payments for geothermal and solar thermal that are related to heat have been subtracted from the Commission's estimates of annual generation in 2010 (these proportions are 2 per cent and 1 per cent respectively). [c] Includes CHP, fuel cells, landfill gas, biomass, hydropower, marine, microturbines and municipal waste.

Sources: US Treasury Department (2011b, 2011c), Productivity Commission estimates.

K.7 Renewable Portfolio Standards

A majority of US states have enacted renewable portfolio standards (RPSs) — targets to increase the use of renewable energy. Generally these are expressed as a longer-term target (for example, 20 per cent renewable energy by 2020), with less stringent targets gradually ramping up over the years. In some cases, the targets are simply aspirational, and do not include any mechanism for achieving the target or penalty for failure. Other schemes include incentives and penalties. The Commission did not attempt to estimate the subsidy equivalent of schemes with no compliance mechanism.

While RPSs differ across the states, there are some features that are common to most. Most schemes place an obligation on electricity utilities to provide a certain proportion of their total sales of electricity from renewable sources. In several states, the RPSs include 'carve outs' that mandate that a proportion of the target must come from particular renewable technologies, such as solar PV. Compliance is generally demonstrated through the surrender of renewable energy certificates (RECs) — one REC is created for each MWh of electricity generated from

approved renewable sources. Some states allow utilities to meet targets with RECs created in other states.

The Commission estimated the subsidy equivalent to RPSs in a subset of states for 2009.[3] A number of states were excluded from the analysis for reasons of data availability and relative significance (the excluded states and the reasons for exclusion are set out below).

The Commission's preferred approach to estimating the subsidy equivalent for each RPS is to use the total number of RECs surrendered in 2009 for additional 'induced' generation, multiplied by the average REC price. This is the approach that was taken for similar schemes in Australia and the United Kingdom. However, this information was not available for most RPS states. The Commission's analysis suggests that many electricity utilities meet their RPS obligations through direct ownership of renewable sources, or through bilateral contracts with renewable energy generators. This means that REC trading appears to be limited and data on REC prices are not readily available. Instead, the Commission has used a number of proxies and assumptions to derive illustrative estimates of the subsidy equivalent and abatement. The following sections describe the approaches used for each state.

For each state, the Commission attempted to estimate the proportion of renewables that have been induced by that state's RPS. This was done by comparing generation in the years prior to the commencement of the scheme with the RPS targets for 2009. In some cases, the Commission concluded that the RPS has probably not induced any additional generation to date.

While the approach taken to estimate the subsidy equivalents varies from state to state, the results for each state are of a similar order of magnitude to the estimates for other jurisdictions. Where the estimates for a state are significantly larger or smaller than for other states, the Commission has attempted to explain the divergence.

The Commission has not carried out sensitivity analysis on the results of the analysis. The reason is that there is only one parameter that stands out as an candidate for such analysis: the emissions intensity of the counterfactual generator. The Commission's estimates of the abatement attributable to each RPS are based on estimates of the marginal emissions factor in each of the ten US electricity markets (section K.1). While these are only estimates, the Commission did not identify any

[3] The Commission assessed the effects of RPSs in the following states in 2009: California, Minnesota, Colorado, Massachusetts, Connecticut, Illinois and Montana. For New York, the year of analysis is the year to 30 April 2010. For New Mexico, the Commission was only able to obtain data for 2007.

alternatives that would be strong candidates for use in sensitivity analysis. As such, it was determined that such analysis would not add significantly to the study.

California

California has the highest renewable energy target of all the US states — 33 per cent of retail sales must be met by renewable energy by 2020 (the target for 2010 was 33 per cent). The California Public Utilities Commission (Fitch 2011) stated that total procurement of RPS-eligible renewables by utilities in California was around 27 TWh in 2009 (15.4 per cent of total electricity sales). Almost all of this was accounted for by three utilities: Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric.

Policy-induced generation

The California RPS was adopted in September 2002. Prior to the adoption of the scheme, California already had significant renewable energy capacity. Fitch (2011) stated that RPS eligible procurement in 2003 was equal to around 22 TWh. The Commission has assumed that only generation in excess of the 2003 figure should be considered to have been induced by the policy. (That is, around 5 TWh in 2009.)

Estimating the subsidy equivalent

There is little public information on the cost of renewables in California that could be used to estimate the subsidy equivalent. Instead, the Commission has used the following information from the Pacific Gas and Electric (PGE) Company's 2009 annual report (PGE 2009) and its 2010 RPS compliance report (PGE 2011).

- In 2009, PGE's total renewable procurement target was 11.5 TWh — 14.2 per cent of PGE's total retail electricity (PGE 2011).
- PGE stated that it paid out US$706 million in 2009 for 'renewable energy and capacity payments' that accounted for 7 per cent of its electricity sources (PGE 2009, p. 106). The Commission has assumed that this is equal to around 5.7 TWh (= (11.5 TWh / 0.142) x 0.07). (The implication of this calculation is that PGE achieved almost half of its RPS obligations through renewables that the company owned, rather than purchased from other firms.)
- This implies that PGE paid around US$124/MWh for renewables. The Commission has assumed that this is a reasonable estimate of the average cost of renewables for the three major electricity utilities in California.

- In 2009, PGE purchased approximately 43 TWh of electricity (including renewables and non-renewables). The average price it paid was US$0.082/kWh ($82/MWh) (PGE 2009). The Commission was not able to obtain data on the price that PGE paid for non-renewable electricity. Instead, the Commission has used the figure of $82/MWh as a proxy estimate of the cost of conventional electricity. This is likely to imply that the estimate of the subsidy to renewables is a lower-bound.
- Hence, the Commission's lower-bound estimate of the production subsidy equivalent for renewables purchased by PGE in 2009 is around US$42/MWh (=US$124 – US$82). Using the Commission's approach for estimating the production subsidy equivalent, this would be the imputed price of RECs.

The Commission has used these assumptions to estimate the subsidy equivalent from the California RPS of US$206 million (A$224 million) (table K.7).

Table K.7 **California RPS calculations**
United States, 2009

Variable	*Units*	*Value*
Total RPS-induced generation	GWh	4 851
Production subsidy equivalent	US$/MWh	42
Subsidy equivalent	**US$m (2009)**	**206**
	A$m (2010)	**224**

Sources: Fitch (2011); PGE (2009, 2011); Productivity Commission estimates.

Illinois

Under the Illinois RPS, privately-owned utilities that serve over 100 000 customers are obliged to obtain a minimum percentage of their electricity from renewables. In 2009, the RPS was 4 per cent, and in each year, 75 per cent of total renewables must come from wind. There are two utilities that are of sufficient size to have obligations under the scheme (ComEd and Amaren Corporation).

Policy-induced generation

The Illinois RPS was introduced in 2007, and allows utilities to meet their RPS obligations using new or existing renewables. Total renewable generation in 2006 was 1 TWh (EIA (US) 2007). Renewable generation in 2009 was 3.7 TWh. Therefore, around 28 per cent of total 2009 renewable generation in Illinois existed in 2006. This suggests that the policy had a significant impact on investment in

renewables, particularly wind power. To reflect this, the Commission has assumed that 72 per cent of renewable generation in Illinois can be attributed to the RPS.

Estimating the subsidy equivalent

The Commission obtained data on the number of RECs purchased and the prices paid by ComEd and Amaren Corporation to meet their obligations for wind energy and other renewables (Evolution Markets 2009). These data were used to estimate the subsidy equivalent paid out by each company (table K.8). It is not clear why ComEd paid significantly more than Amaren for its wind RECs. In a competitive market, both utilities would be expected to pay the same price. One possible explanation is that some utilities enter into long-term contracts for the purchase of RECs. This could lock them (or the seller) into higher (or lower) REC prices in a given year. Another possible explanation is that the REC market might not be very liquid. Alternatively, the firms could have purchased RECs at different times during the year, meaning that the difference could be explained by REC price fluctuations.

Table K.8 **Illinois RPS calculations**
United States, 2009

Variable	*Units*	*ComEd*	*Amaren Corporation*	*Total*
Total RECs purchased	millions	1.6	0.7	2.3
Wind[a]	millions	1.2	0.5	1.7
Other renewables	millions	0.4	0.2	0.6
RECs purchased for induced generation[b]				
Wind	millions	0.8	0.4	1.2
Other renewables	millions	0.3	0.1	0.4
Price paid per REC				
Wind	US$ (2009)	21.13	16.66	
Other renewables	US$ (2009)	13.69	13.46	
Subsidy equivalent				
Wind	$USm (2009)	18	6	24
Non-wind	$USm (2009)	4	2	6
Total	**$USm (2009)**	**22**	**8**	**30**
	A$m (2010)	**24**	**9**	**33**

a Assuming that 75 per cent of RECs purchased by utilities are for wind power, as per the RPS requirement.
b Assuming that 72 per cent of renewables covered by the RPS are policy-induced.

Sources: Evolution Markets 2009; Productivity Commission estimates.

New York

New York has a state renewable energy target of 30 per cent by 2015. The state RPS operates through a tender system, whereby the responsible authority (NYSERDA):

> … pays a production incentive to renewable electricity generators selected through competitive solicitations for the electricity they deliver for end use in New York. In exchange for the production incentive, the renewable generator transfers to NYSERDA all rights and/or claims to the RPS Attributes associated with each MWh of renewable electricity generated … (NYSERDA 2010a, p. 5)

NYSERDA does not purchase renewable electricity. Rather, the payment is for the 'RPS attributes', including 'reductions in harmful pollutants and emissions, such as carbon dioxide and oxides of sulphur and nitrogen' (NYSERDA 2010a, p. 5). These are 'similar to Renewable Energy Certificates that are commonly used in other RPS programs' (NYSERDA 2010a, p. 5). The value of reductions in non-greenhouse pollutants could be making some contribution to the price of 'RPS attributes'. However, the Commission was not able to unbundle the greenhouse gas portion of the price from other elements. Hence, the Commission has assumed that the value of an 'RPS attribute' can be used in the same way that REC prices are used to estimate the subsidy equivalent for other schemes.

The RPS consists of two 'tiers'. The 'main tier' (tier 1)consists mainly of medium and large-scale generators, while the 'customer-sited' tier consists of smaller facilities, such as photovoltaic systems. Due to changes in the funding of the program, the Commission was not able to access data that could be used to calculate the subsidy equivalent for the customer-sited tier. However, this tier of the program accounted for only around 2 per cent of total RPS procurement in the year to 30 April 2010. Hence, it is likely that excluding this part of the scheme from the analysis will not have a significant effect on the estimated subsidy equivalent or abatement.

Policy-induced generation

Proceedings to enact the RPS began in February 2003. NYSERDA states that '[o]nly renewable energy systems installed on or after January 1, 2003 are eligible to participate in the RPS' (2010a, p. 7). Based on this, the Commission has assumed that all renewables that create RPS attributes are policy induced.

Estimating the subsidy equivalent

The Commission has estimated the subsidy equivalent using the price of 'RPS attributes' in the same way it would normally use REC prices. To date, NYSERDA has held five 'solicitations' for the main tier of the program (medium and large-scale generators). The weighted average price of RPS attributes through these solicitations was US$18 for each RPS 'attribute' associated with a MWh of renewable electricity. The total annual average renewable electricity generation was around 4.3 TWh. The Commission has used these figures to estimate the subsidy equivalent arising from the RPS (table K.9).

Table K.9 **New York RPS calculations**

Main tier, May 2009 – April 2010

Variable	*Units*	*Value*
Tier 1 annual generation	TWh	4.3
Weighted average incentive payment	US$ (2009)	18
Subsidy equivalent	**US$m (2009)**	**78**
	A$m (2010)	**85**

Sources: NYSERDA (2010a); Productivity Commission estimates.

Montana

The Montana Renewable Energy Standard (RES) required 5 per cent of electricity sales to come from renewables in 2009, 10 per cent in 2010, and 15 per cent in 2011 and thereafter (UCS 2008a). The scheme applies to public utilities regulated by the Montana State Public Service Commission, and to competitive electricity suppliers. In 2004, these suppliers amounted to approximately 58 per cent of state electricity sales (UCS 2008a). The RES incorporates REC trading, and a penalty of US$10/MWh for non-compliance.

Policy-induced generation

The Montana RES was enacted in April 2005. Only facilities that commenced operation after 1 January 2005 are counted toward the scheme. For the purpose of estimating the subsidy equivalent, the Commission assumed that all eligible generation is policy induced (that is, firms with RES obligations adhere to the rules of the scheme and only submit RECs for electricity generated from facilities that commenced during 2005 or later).

Estimating the subsidy equivalent

The EIA (US) (2010e) stated that total electricity sales in Montana in 2009 were 14 TWh. The Commission assumed that the RES applied to 58 per cent of total sales, and that the utilities covered by the scheme met their obligation to supply 5 per cent of their total sales from post-2005 renewables.

The Commission was not able to locate data on REC prices in Montana. Instead, the Commission used the penalty price ($10/MWh) to estimate an upper bound of the subsidy equivalent (table K.10). Given the relatively low penalty price, it is possible that the RPS is not inducing significant quantities of renewable generation (for example, utilities might find it cheaper to simply pay the penalty). This should be taken into account when interpreting the results.

Table K.10 **Montana RES calculations**
United States, 2009

Variable	*Units*	*Value*
Total electricity sales	TWh	14.3
Electricity sales by utilities with RES obligations[a]	TWh	8.3
Total RPS obligation of covered utilities	TWh	0.42
Penalty price	US$/MWh	10
Subsidy equivalent[b]	**US$m (2009)**	**4.2**
	A$m (2010)	**4.6**

a Assuming that 58 per cent of total sales are by utilities with RES obligations. **b** This estimate represents an upper bound. If the REC price is lower than the penalty price (US$10/MWh), or the RES obligation was not met, the subsidy equivalent would be smaller.

Sources: EIA (US) (2010e); UCS (2008a); Productivity Commission estimates.

Minnesota

The Minnesota RES imposed an obligation on the utility company Xcel Energy to provide 15 per cent of its retail electricity sales from renewables in 2010. For other utility companies, the figure was 7 per cent. The Commission was not able to determine whether there was a specific obligation for 2009.

Policy-induced generation

Minnesota's total renewable generation in 2006 (the year before the RES was enacted) was around 3.6 TWh (EIA (US) 2007). In 2009, renewable generation was around 7.5 TWh (EIA (US) 2010d). The Commission assumed that only the additional generation (around 3.9 TWh) can be attributed to the RES.

Estimating the subsidy equivalent

The Commission was not able to access data on REC prices in Minnesota. However, because Minnesota is in the same region as Illinois, and operates on the same electricity grid, the Commission has used the Illinois REC prices to estimate the average REC price in Minnesota (table K.11). This is based on the assumption that the marginal costs of renewables in the two states are similar.

Table K.11 **Minnesota RES calculations**
United States, 2009

Variable	*Units*	*Value*
Total renewable generation (2006)	TWh	3.6
Total renewable generation (2009)	TWh	7.5
Estimated RES-induced generation	TWh	3.9
Estimated REC price[a]	US$/MWh	17.30
Subsidy equivalent[b]	**US$m (2009)**	**68**
	A$m (2010)	**74**

[a] Based on the average REC price for wind energy in Illinois in 2009 (US$18.90) and non-wind RECs (US$13.58). The estimate was weighted 70 per cent wind and 30 per cent 'other'.

Sources: EIA (US) (2007, 2010d); Productivity Commission estimates.

Colorado

Under the Colorado Renewable Energy Standard, at least 5 per cent of 2009 electricity sales by privately-owned utilities were required to be sourced from renewables. For rural cooperatives and municipal utilities the figure was 1 per cent. The scheme includes a 'carve out' that at least 4 per cent of total renewable generation must come from solar electric technologies.

Policy-induced generation

Total electricity sales in Colorado in 2009 were around 51 TWh, which implies that up to 2.6 TWh of renewables would be required to meet the RES target (this is an upper-bound estimate that would only apply if all electricity was supplied by privately-owned utilities). The Colorado RES commenced in 2004. In 2004, total renewable generation in Colorado was less than 1.5 TWh, most of which came from hydroelectricity (EIA (US) 2007). By 2009, the figure had risen to 5.3 TWh, with most of the growth accounted for by wind power (EIA (US) 2010e). That implies that the total new (post-2004) renewable generation in Colorado is more than is required by the state RES. The excess wind could have been installed as a result of

other programs, (such as the Federal PTC or Treasury Grants, or other state programs. Alternatively, the capacity could have been installed in order to export renewable energy (and RECs) to other states with RPSs. Another possibility is that the capacity could have been installed to meet future renewable energy targets.

The Commission did not attempt to identify the reasons for the relatively high level of capacity in Colorado (relative to the RES target), because this is not required for the calculation of the subsidy equivalent and abatement attributable to the RES. The relevant figure for these purposes is how much renewable energy was subsidised under the RES. To estimate this figure, the Commission assumed that to meet the RES obligation, utilities purchased all of the existing renewable energy (assumed to equal 1.5 TWh) and 1.1 TWh of new wind power. Note that this is likely to overestimate the total RES obligations in Colorado in 2009, because utilities that are not privately-owned have less stringent obligations. As such, the Commission's estimates of abatement and subsidy equivalent represent an upper bound.

Estimating the subsidy equivalent

The Commission's analysis suggests that Colorado utilities meet their REC obligations through bilateral contracts with renewable generators, or through privately-owned sources. Hence, the Commission was not able to access data on REC prices.

Instead, the Commission imputed the value of RECs by using data on Xcel Energy's Windsource program. This scheme provides a mechanism for customers of Xcel Energy to purchase additional renewable energy (beyond that required under the RES). Under this program, for each MWh of renewable electricity purchased through Windsource that would not have been purchased otherwise, one REC is retired. Hence the price of renewables purchased for the Windsource program can be used as a proxy for the REC price. Specifically, the 'Windsource premium' represents the price consumers are prepared to pay for RECs, and hence may be an upper-bound estimate of the REC price, if consumers are motivated by environmental concerns to pay a premium to retire RECs.

Xcel Energy stated that it anticipated that its sales through this program would be 220 GWh in 2009 (Xcel Energy 2009), and that the 'Windsource premium' for the last nine months of 2009 would be US$3.4 million. The Commission assumed that the total Windsource premium for 2009 would be US$4.5 million (= US3.4 million x 1.33). This implies that the premium per MWh (and the imputed upper bound of the REC price) would be US$20.61. This assumption was used to estimate the subsidy equivalent for the Colorado RES (table K.12).

Note that this estimate does not account for the solar 'carve out' under the scheme (data were not available). However, the carve out target is small (4 per cent of total renewables), and the exclusion of this part of the scheme would not be expected to have a material effect on the estimates.

Table K.12 **Colorado RES calculations**
United States, 2009

Variable	*Units*	*Value*
Estimated policy-induced renewable generation (upper bound)	TWh	1.1
Estimated REC price (upper bound)[a]	US$/MWh	20.61
Subsidy equivalent[b]	**US$m (2009)**	**23**
	A$m (2010)	**25**

[a] Based on the Xcel Energy Windsource program.

Sources: EIA (US) (2007, 2010d); Productivity Commission estimates.

New Mexico

The New Mexico RPS obliged privately-owned utilities to derive 5 per cent of their retail sales from renewables since 2006, and requires 10 per cent from 2011. Three utilities have obligations under the RPS: El Paso Electric; Public Service Company of New Mexico; and Southwestern Public Service. The Commission was not able to locate data on the retail sales or RPS obligations of these companies for 2009, and instead has analysed the RPS for 2007.

Policy-induced generation

The New Mexico RPS came into force in 2004. Generators are permitted to use renewable generation assets that were in their generation portfolios as of July 2004 to meet their RPS obligations, except for hydro power, which must have been brought into service after 2007. The Commission was not able to access data on the renewable assets that were in utilities' portfolios in 2004, and has made the simplifying assumption that all generation used to meet the New Mexico RPS was policy-induced. This assumption might overstate the subsidy equivalent and abatement attributable to the New Mexico RPS.

Estimating the subsidy equivalent

The Commission was not able to obtain data on New Mexico REC prices. However, as is the case for Colorado, the utility companies in New Mexico operate voluntary schemes to enable electricity consumers to purchase additional renewable energy (New Mexico Public Regulation Commission 2008). The Commission used these prices as a proxy for the REC prices in its estimates of the subsidy equivalent (table K.13).

Table K.13 **New Mexico RPS calculations**
United States, 2007

Variable	*Units*	*Value*
RPS obligation (2007)		
El Paso Electric	GWh	96
Public Service Company of New Mexico	GWh	503
Southwestern Public Service	GWh	246
Estimated REC price[a]		
El Paso Electric	US$/MWh (2007)	22.80
Public Service Company of New Mexico	US$/MWh (2007)	16.90
Southwestern Public Service	US$/MWh (2007)	30
Subsidy equivalent[b]	**US$m (2007)**	**18**
	A$m (2010)	**20**

a Based on the voluntary programs run by each utility for the purchase of renewable energy. **b** Estimated as the RPS obligation multiplied by the estimated REC price for each utility, then added for a total figure.

Sources: New Mexico Public Regulation Commission (2008); Productivity Commission estimates.

Massachusetts

The Massachusetts Renewable Energy Portfolio Standard (REPS) requirement for 2009 was for 4 per cent of electricity to be generated from renewables that were installed during 1998 or later ('Class I' renewables). Massachusetts also imposes an obligation to use energy from generators that existed before 1998 ('Class II' renewables). Because 'Class II' renewables are not induced by the policy, the Commission did not include these in the analysis. Finally, there is an obligation to use a certain proportion of 'alternative' energy technologies, including flywheel energy storage and CHP. The alternative energy obligation was relatively minor (164 GWh), and for this reason was not considered in the analysis. Hence, the Commission's estimate of the subsidy equivalent and abatement for Massachusetts applies only to the 'Class I' portion of the scheme.

Policy-induced generation

The Massachusetts REPS came into force in 1997. Only generation that was put into service in 1998 or later is eligible to meet the target for Class I renewables. For this reason, the Commission has assumed that all generation that was used to meet this obligation was policy-induced.

Estimating the subsidy equivalent

In 2009, the Class I obligation was equal to around 2 TWh. In February 2010, Evolution Markets (2010, p. 10) stated that '2009 Massachusetts Class 1 RECs are currently assessed between $23.50 and $25.50'. The Commission assumed that the REC price in 2009 was US$24.50. This implies that the subsidy equivalent was around US$47 million (A$52 million) in 2009 (table K.14)

Table K.14 **Massachusetts REPS calculations (Class I Only)**
United States, 2009

Variable	*Units*	*Value*
2009 Class I REC obligation	million	1.9
Estimated 2009 Class I REC price	US$ (2009)	24.50
Subsidy equivalent (cost of RECs retired)	**US$m (2009)**	**47**
	A$m (2010)	**52**

Sources: Commonwealth of Massachusetts Department of Energy Resources 2010; Productivity Commission estimates.

Connecticut

The Connecticut RPS includes targets for the use of renewables and CHP. The 2009 targets were:

- 6 per cent from 'Class I' — includes solar, wind, some biomass, biogas and some hydropower
- 3 per cent from 'Class II' — waste to energy, biomass that began operation before 1998, and small hydropower
- 3 per cent from 'Class III' — CHP.

The Commission was only able to access data on the price of Class I RECs. For this reason, the estimates of the subsidy equivalent and abatement apply only to that portion of the RPS.

Policy-induced generation

Under the Connecticut RPS, new and existing generation can be used to meet the Class I target (except for hydropower, which is only eligible if installed after 2003). The Commission was not able to access data on how much new generation used to meet the target. Hence, it has made the simplifying assumption that all generation used to meet the target is policy-induced. This may tend to overstate the subsidy equivalent and the abatement attributable to the Connecticut RPS.

Estimating the subsidy equivalent

Based on data from a REC market operator (Evolution Markets 2009, p. 1), the Commission assumed that the 2009 price of Connecticut Class I RECs was US$20.

Total electricity sales in Connecticut in 2009 were around 29.7 TWh (EIA (US) 2010e). The Commission assumed that the Class I obligation of 6 per cent of total sales was met. This implies that around 1.8 TWh of Class I renewables were supplied in 2009. Using this information it is possible to estimate the subsidy equivalent of the Connecticut RPS (table K.15).

Table K.15 **Connecticut RPS calculations (Class I only)**
United States, 2009

Variable	*Units*	*Value*
2009 Class I REC obligation	million	1.8
Estimated 2009 REC price	US$ (2009)	20
Subsidy equivalent (cost of RECs retired)	**US$m(2009)**	**36**
	A$m (2010)	**39**

Sources: EIA (US) (2010e); Evolution Markets (2009); Productivity Commission estimates.

States that were not analysed

The Commission analysed only a sub-set of states. There were a variety of reasons for excluding states:

- Fourteen states do not have an RPS (Alabama, Alaska, Arkansas, Florida, Georgia, Idaho, Indiana, Kentucky, Louisiana, Mississippi, Nebraska, South Carolina, Tennessee and Wyoming).
- Seven states have RPSs that set an 'aspirational' target, but with no compulsion for electricity retailers or generators to achieve the target (North Dakota, South Dakota, Oklahoma, Utah, Vermont, Virginia and West Virginia).

- Seven states have an RPS that commenced in 2011, and as such data, data were not available (Iowa, Kansas, Michigan, Missouri, North Carolina, Oregon and Washington).

States where the RPS does not appear to be inducing significant generation

In some states the 2009 RPS target was relatively low, compared to the renewable generation that existed before the introduction of the policy. In these cases, the Commission concluded that the RPS probably did not induce significant additional renewable generation in 2009. In general, this assessment was made by comparing historical generation data (EIA (US) 2007) with 2009 generation data and the state RPS targets. States omitted on this basis include the following:

- Pennsylvania — the Pennsylvania Alternative Energy Portfolio Standard (AEPS) was enacted in November 2004. Generation from both new and existing sources can be counted toward AEPS obligations. Data from EIA (US) (2007) show that 2004 renewable generation was around 2.2 TWh from hydropower and 2.3 TWh from 'other renewables'. The 2009 AEPS obligation was for around 1.2 TWh — less than the generation that occurred prior to the AEPS (Pennsylvania Public Utility Commission 2010).
- New Hampshire — the 2009 RPS target was for 6 per cent of total electricity sales to be derived from renewables. However, 5.5 percentage points of the target could be met with existing renewables. Hence, the Commission considers that the RPS probably led to little additional renewable generation in 2009, and as such has not attempted to estimate a subsidy equivalent.
- Nevada — the RPS was introduced in 2004. It obliges utilities to meet a percentage of total electricity sales from renewable energy or efficiency measures. In 2009, the figure was 12 per cent, with a maximum of 3 per cent to come from efficiency measure. Hence, the RPS set a minimum of 9 per cent renewable generation. In 2004, renewables accounted for around 8.4 per cent of Nevada's total generation (EIA (US) 2007). Given that the 2009 target is only slightly above this figure, the Commission has opted to exclude Nevada.

In addition, the Commission excluded Texas from its analysis because the 2009 REC price was approximately zero (Linn 2011). Maryland was excluded for similar reasons. Data from the Public Service Commission of Maryland implied that the 2009 REC price was only around A$1.20 per REC. This suggests that the Maryland RPS did not lead to significant additional renewable generation in 2009.

States with a small target for new renewables in the year of analysis

Some states had a relatively small target for new renewables in the year of analysis (2009). These states were excluded from the analysis because it is unlikely that the subsidy equivalents were material relative to those in other states with larger targets. States excluded on this basis were:

- Arizona (2 per cent new renewables in 2009)
- Maine (2 per cent new renewables in 2009)
- Ohio (0.25 per cent renewables in 2009)
- Wisconsin (no reduction in the state's renewable energy generation over the period 2006–2009, and a 2 per cent increase in 2010 renewables against a baseline).

States with less than 1 TWh of renewable generation in 2009

The Commission has opted to exclude from its analysis states with a reported generation from renewables of less than 1 TWh in 2009.

Between them, the two largest states that the Commission has assessed (California and New York) generated over 85 TWh of electricity from renewable sources in 2009. States with low levels of renewable generation could still have effective RPSs if their laws permit imported RECs to count toward the target. However, as a proxy measure, the Commission has assumed that in states with less than 1 TWh of renewable generation in 2009, the subsidy equivalents would be small, relative to the larger states in the analysis. States excluded on this basis (and their 2009 renewables generation) are:

- Delaware (126 GWh)
- Rhode Island (150 GWh)
- New Jersey (790 GWh)
- Hawaii (817 GWh).

K.8 Abatement and the implicit abatement subsidies for federal policies and state RPSs

Due to overlap between the federal Treasury Grants and Production Tax Credits, and state Renewable Portfolio Standards, the Commission has estimated the abatement and implicit abatement subsidy from these three schemes as a group. In estimating abatement, the Commission assumed that:

- all renewable generators eligible to receive either the federal Production Tax Credits or the federal Treasury Grants took these subsidies. As such, abatement from the majority of renewable sources is covered under these two schemes
- eligible renewable generation from the Renewable Portfolio Standards is fully covered by the federal schemes
- because eligible renewable generators are only able to access one of the two federal level programs, there is no overlap between these two scheme.

Therefore, abatement for these three policies is estimated to be equal to the abatement from the Treasury Grants and the Production Tax Credits. This is not to suggest that there is zero abatement from the Renewable Portfolio Standards, or that the abatement estimate for the two federal level polices is solely attributable to those programs. In many cases, it is likely to be the combination of state and federal-level subsidies that induces additional renewable generation. In many cases, the state level Renewable Portfolio Standard may be the 'binding' policy that drives new renewable generation in a given state. However, as the renewable generation from the state Renewable Portfolio Standards is already covered by the federal level programs, the Commission excluded this generation to avoid double counting abatement.

Estimating abatement

As discussed in section K.1, the US electricity system is made up of ten separate electricity markets, each of which uses different electricity generation sources. Hence, each have considerably different emissions intensities. Therefore, abatement from the Treasury Grants and Production Tax Credits depends on the location of generation from each new renewable electricity source.

Total generation eligible for the Production Tax Credits was estimated to be 74.9 TWh (table K.4) based on the proportion of eligible generation in each electricity grid. This implies an abatement estimate of 51 Mt CO_2 (table K.16).

For the Treasury Grants, the Commission was unable to obtain state-level data on renewable generators receiving grants. However, it was able to obtain state-level data on total renewable electricity capacity supported by Treasury Grants. The Commission used these data to weight the marginal emissions intensities of the 10 US electricity markets. This provides a weighted average marginal emissions intensity for the US as a whole of 0.67 t CO_2/MWh (table K.17).

Table K.16 **Estimated abatement from the PTC**

United States, 2010

Electricity market	*Total eligible generation*	*Marginal emissions factor*	*Abatement*
	TWh	t CO_2/MWh	Mt CO_2
California (CAISO)	4.2	0.41	1.7
Midwest (MISO)	22.1	0.91	20.0
New England (ISO-NE)	0.4	0.60	0.3
New York (NYISO)	2.6	0.60	1.6
Northwest	11.0	0.47	5.2
PJM	3.0	0.79	2.4
Southeast	1.9	0.77	1.4
Southwest	4.8	0.47	2.2
Southwest Power Pool	6.0	0.79	4.7
Texas (ERCOT)	18.9	0.60	11.4
Total	74.9		51

Sources: Vivid Economics (2011); Productivity Commission estimates.

Abatement from the Treasury Grants program was estimated using the Commission's estimate of total annual generation and the weighted average emissions intensity for the United States as whole. This provides an estimate of abatement from the Treasury Grants program of 15.1 Mt CO_2.[4]

Based on the above analysis, abatement from the Treasury Grants, Production Tax Credits and state-based Renewable Portfolio Standards combined was estimated to be 66 Mt CO_2.

Estimating the implicit abatement subsidy

The implicit abatement subsidy for renewables supported by the Treasury Grants, Production Tax Credits and state-based Renewable Portfolio Standards was estimated by adding the subsidy equivalent estimates for each measure (sections K.5–K.7) and dividing this by the combined abatement estimate above. This provides an implicit abatement subsidy in the range US$37-US$42/t CO_2 (A$41-A$46) (table K.18).

4 Note that the Commission's estimates of abatement assume that all new generation supported by the Treasury Grants have zero emissions (renewable generators). This is not the case for CHP. However, the Commission was unable to obtain data on the annual generation or location of CHP plants supported by the program in order to estimate abatement from CHP. This does not have a material effect on the estimates as CHP is a very small component of the program (0.09 per cent of total payments in 2009 and 2010).

Table K.17 **Estimated weighted average marginal emissions factor[a]**

Electricity market	*Estimated installed capacity (as of February 2011)*	*% of total installed capacity*	*Marginal emissions factor*
	MW	%	t CO_2/MWh
California (CAISO)	331	3	0.41
Midwest (MISO)	3 056	31	0.91
New England (ISO-NE)	218	2	0.60
New York (NYISO)	481	5	0.60
Northwest	1 907	20	0.47
PJM	580	6	0.79
Southeast	89	1	0.77
Southwest	458	5	0.47
SPP (Southwest Power Pool)	161	2	0.79
Texas (ERCOT)	2 447	25	0.60
Weighted average			0.67

a Installed capacity by electricity market was estimated by Vivid Economics by allocating states (and total capacity by state) to one of the 10 electricity markets based on the location of states and by using information from the Federal Energy Regulatory Commission. Due to insufficient data, Alaska, Hawaii and Puerto Rico were not included in the analysis. The exclusion of these states is not expected to have a material effect on the Commission's estimate of the average emissions intensity as combined these states represent around 0.08 per cent of total installed capacity.

Sources: US Treasury Department (2011c), Productivity Commission estimates.

Table K.18 **Implicit abatement subsidies**

United States, 2010

	Subsidy equivalent		*Abatement*	*Implicit abatement subsidy*	
	US$	A$m	Mt CO2	US$/t CO_2	A$/t CO_2
Renewable Electricity Production Tax Credits	1 571	1 708	..	..	..
Treasury Grants			..	..	..
- 3 per cent discount rate	385	418	..	..	..
- 7 per cent discount rate	541	588	..	..	..
- 11 per cent discount rate	719	782	..	..	..
State Renewable Portfolio Standards	512	557	..	..	..
Total	**2 468–2 803**	**2 684–3 047**	**66**	**37–42**	**41–46**

Source: Productivity Commission estimates. .. Not applicable

K.9 The California Solar Initiative

The California Solar Initiative (CSI) provides subsidies for the installation of solar panels. These can take two forms

- For small solar systems (under 30kW) — an up-front payment based on the capacity of the system (the 'expected performance-based buydown' (EPBB) payment). This is paid upon completion of the system.
- For larger solar systems — an annual payment for five years based on the actually generation of the system (the performance-based incentive (PBI payment).

The rate of subsidy is dependent on the amount of solar installed — as more solar is installed, the tariff gradually steps down. The rates started at US$2.80/watt for the EPBB and US$0.50/kWh for the PBI in 2007, and will reach US$0.20/watt (EPBB) and US$0.03/kWh (PBI) by the end of the scheme. As of 2010, much of the state is in step 8, which implies an EPBB payment of US$0.35/watt, and a PBI payment of US$0.05/kWh (RFF 2011).

The scheme has a budget of US$2.2 billion between 2007 and 2016, and a goal to install 1940 MW of new solar capacity by 2016.

Estimating the subsidy equivalent

The Commission's approach for estimating the subsidy equivalent was different for the EPBB payments and the PBI payments.

EPBB payments

As the EPBB is provided as an upfront cash subsidy, the subsidy equivalent from this part of the CSI was estimated as a capital subsidy.

According to the CEC and CPUC (2011), by the end of 2010, US$361 million of EPBB payments had been classed as completed since the scheme commenced. Converting to 2010 values, this implies that the total outlay paid under the EPBB scheme was US$365 million.

Using a discount rate of 7 per cent, and an expected economic lifetime of solar PV of 20 years, the annualised subsidy equivalent of the EPBB scheme was estimated at US$34 million (A$37 million) (table K.19).

Table K.19 **Estimating the EPBB payments**
California, 2010

Data	*Value*
Total payments made	US$365m
Discount rate	7 per cent
Lifetime of solar panels	20 years
Annualised cost (subsidy equivalent)	**US$34m**
	A$37m

Source: Productivity Commission estimates.

PBI payments

The PBI payments are paid out annually over five years on the basis of actual generation. Therefore, these payments are similar to production subsidy schemes, such as feed-in tariffs and renewable energy certificate schemes, and the subsidy equivalent was estimated on this basis.

While no data on the actual total PBI payments over a year were available, an estimate of the annual payments can be implied from data from the CEC and CPUC (2011).

As of the end of December 2010, owners of installed solar PV panels were expected to receive US$452 million under the PBI over the five years (CEC and CPUC 2011). This includes those that are still receiving payments, and those whole payments had recently ceased, but would still have been paid in the previous year. Dividing this figure by 5 provides an estimate of the expected annual production subsidy to solar panels under the PBI payments (US$90 million).

Total

The annual estimated subsidy equivalent provided by the CSI is the sum of the PBI and EPBB subsidy equivalents — US$125 million (A$136 million).

Sensitivity analysis

The Commission used two alternative discount rate scenarios for the EPBB estimates: 3 per cent and 11 per cent.

- A 3 per cent discount rate resulted in a subsidy equivalent estimate of US$115 million (A$125 million).

- An 11 per cent discount rate resulted in a subsidy equivalent estimate of US$136 million (A$148 million).

Estimating total generation

As of the end of 2010, 461 MW of solar capacity had been subsidised under the CSI. Annual generation is estimated using capacity factors for the Californian Self Generation Incentive Program (section K.11) reported by Iltron (2010) — 17 per cent for solar. Therefore the estimated annual generation was 690 GWh.

Summary

Table K.20 displays the results of the analysis for the CSI. The subsidy equivalent estimates range from US$115 million to US$136 million (A$125 million to A$148 million).

Table K.20 **Summary, California Solar Initiative**
California, 2010

Scenario	*Subsidy equivalent*		*Generation*
	A$m	US$m	GWh
'Central'	136	125	690
Low discount rate	125	115	690
High discount rate	148	136	690

Source: Productivity Commission estimates.

K.10 New Solar Homes Partnership

The California New Solar Homes Partnership (NSHP) aims to encourage the use of solar PV systems on new homes. The NSHP offers more generous subsidies than the CSI for new homes in specified areas. The scheme objective is for an additional 400 MW of installed solar capacity by 2016.

The subsidy rate currently ranges from US$2.50/watt to US$2.60/watt for 'market rate housing', and US$3.30/watt to US$3.50/watt for 'affordable housing'. The rebates are paid as a lump sum, once the system is installed.

Estimating the subsidy equivalent

As the NSHP payments are provided up-front payment, the subsidy equivalent was estimated as a capital subsidy. As of the end of 2010, US$29.7 million worth of subsidies had been paid out (Vivid Economics). Converting this to real 2010 currency, the estimated total outlay was US$29.9 million.

Using an interest rate of 7 per cent, and an economic lifetime of 20 years, the annualised subsidy equivalent was estimated to be US$2.8 million (A$3.1 million).

Sensitivity analysis

The Commission used two alternative discount rates in its sensitivity analysis: 3 per cent and 11 per cent.

- Using a 3 per cent discount rate results in a subsidy equivalent estimate of US$2 million (A$2.2 million).
- Using an 11 per cent discount rate results in a subsidy equivalent estimate of US$3.7 million (A$4.1 million).

Estimating generation

As of the end of 2010, 10.5 MW of solar PV had been installed under this scheme (Vivid Economics). Using a capacity factor of 17 per cent (Iltron 2010), this capacity was estimated to produce 15.7 GWh per year.

Summary

Table K.21 outlines the results of the estimate of the California NSHP. The subsidy equivalent estimates range from US$2 million to US$3.8 million (A$2.2 million to A$4.1 million)

Table K.21 **Summary, NSHP**
California, 2010

Scenario	*Subsidy equivalent*		*Generation*
	A$m	US$m	GWh
'Central'	3.1	2.8	15.7
Low discount rate	2.2	2	15.7
High discount rate	4.1	3.7	15.7

Source: Productivity Commission estimates.

K.11 Self Generation Incentive Program

The Self Generation Incentive Program (SGIP) provides up-front capital subsidies for on-site generation facilities. Currently, fuel cells (renewable and non-renewable), wind and energy storage are eligible for the SGIP. Previously, other technologies such as solar and internal combustion units have been eligible. (Note that as past subsidies to these previously eligible technologies are still contributing to abatement, and have a subsidy equivalent in 2010 under the Commission's approach, they are still included in the estimates.)

The current subsidy rates are shown in table K.22, and range from US$1.50/W for wind to US$4.50/W for renewable fuel cells. For systems bigger than 1 MW, the subsidy is 100 per cent of this subsidy rate for the first MW, 50 per cent for capacity between 1 and 2 MW, and 25 per cent for capacity between 2 and 3 MW. No incentive is paid for capacity above 3 MW, and systems above 5 MW are not eligible for the SGIP.

The SGIP was initially conceived as a peak-load electricity reduction measure. However it also has the effect of increasing the use of renewable sources of electricity (CPUC nd).

Table K.22 **Subsidy rates for the SGIP (for the first MW of capacity)**
California, 2010

Technology	*Subsidy rate*
	US$/W
Wind turbine	1.50
Renewable fuel cells	4.50
Non-renewable fuel cells	2.50
Advanced energy storage	2.00

Source: SCE et al. (2010).

Calculating the subsidy equivalent

Effectively, there are two components to the SGIP — payments to renewable technologies, and payments to non-renewable technologies (primarily natural gas). Subsidies to non-renewable technologies are unlikely to lead to any abatement — given the largely gas-based Californian electricity system — and therefore they have not been included in the estimates. Fuel cells, internal combustion engines and micro-turbines fuelled by biomass have been included in the analysis.

According to data from CSEC (2011), as of the end of 2010, US$532 million had been paid out to renewable technologies under the SGIP. This was converted to 2010 values, resulting in an estimated total outlay of US$573 million.

Using an interest rate of 7 per cent, and an average economic lifetime of projects of 20 years, this value was converted into an annualised cost, estimated at US$54 million (A$59 million) (table K.23).

Table K.23 **Estimating the subsidy equivalent, SGIP**
California, 2010

Data	*Value*
Value of payments	US$573 million
Interest rate	7 per cent
Economic lifetime	20 years
Annualised value of payments (subsidy equivalent)	US$54 million
Subsidy equivalent (AU$)	**A$59 million**

Sources: CSEC (2011); Productivity Commission estimates.

Sensitivity analysis

The Commission used two alternative discount rates: 3 per cent and 11 per cent.

- Using a 3 per cent discount rate results in a subsidy equivalent estimate of US$38.5 million (A$41.9 million)
- Using an 11 per cent discount rate results in a subsidy equivalent estimate of US$72 million (A$78.3 million).

Estimating abatement

As of the end of 2010, the SGIP had subsidised:

- 4 MW of wind
- 144 MW of solar
- 22 MW of biomass and waste, of which 3.9 MW was micro-turbines, 10.8 MW was internal combustion units, and 7.9 MW was fuel cells (CSEC 2011).

Iltron (2010) sets out capacity factors for generation subsidised by the SGIP for 2009. These are used as a proxy for 2010 capacity factors, as there is unlikely to be a significant change in capacity factors between 2009 and 2010. According to Iltron (2010):

- the capacity factor for solar PV was 17 per cent. This results in estimated annual generation of 216 GWh
- the capacity factor for wind was 17 per cent. This results in estimated annual generation of 5.8 GWh
- the capacity factor for renewable fuel cells was 51 per cent. This results in estimated annual generation of 35 GWh
- the capacity factor for micro-turbines was 22 per cent. This results in estimated annual generation of 7.5 GWh
- the capacity factor for internal combustion was 28 per cent. This results in estimated annual generation of 26 GWh.

Therefore, the total annual generation supported by the scheme was estimated at 290 GWh (of which 216 GWh was solar).

Sensitivity analysis

Counterfactual emissions intensity

As noted in section K.1, the Commission used an alternate counterfactual emissions intensity of 0.6t/MWh for the Californian schemes. This results in an implicit abatement subsidy estimate of US$311/t CO_2 (A$338).

Summary

The results of the estimation for the SGIP are shown in table K.24. The subsidy equivalent estimates range from US$38.5 million to US$72 million (A$41.9 million to A$78.3 million).

Table K.24 **Summary, Self Generation Incentive Program**
California, 2010

Scenario	*Subsidy equivalent*		*Solar generation*	*Non solar generation*
	A$m	US$m	GWh	GWh
'Central'	59	54	216	74
Low discount rate	42	39	216	74
High discount rate	78	72	216	74

Source: Productivity Commission estimates.

K.12 Emerging Renewable Program

The Californian Emerging Renewable Program (ERP) commenced in 1998, and has provided subsidies for solar PV, wind and renewable fuel cell generation. The scheme is designed to favour small-scale distributed generation. The current subsidy rates vary between US$1.50/watt and US$3.00/watt, depending on the generators fuel type and size (CEC 2010c). Since 2007, this scheme no longer offers incentives for solar, which was the largest component of scheme.

Estimating the subsidy equivalent

Since the commencement of the scheme in 1998, the ERP has provided US$406 million in subsidies (CEC 2010a, 2010b) (US$453 million in 2010 dollars).

Using an interest rate of 7 per cent, and an expected economic lifetime of the subsidised assets of 20 years, the subsidy equivalent was estimated at US$42.7 million (A$46.5 million).

Sensitivity analysis

The Commission used two alternate discount rates for sensitivity analysis: 3 per cent and 11 per cent.

- Using a 3 per cent discount rate results in a subsidy equivalent estimate of US$30.4 million (A$33.1 million).
- Using an 11 per cent discount rate results in a subsidy equivalent estimate of US$56.8 million (A$61.8 million).

Estimating generation

Since the commencement of the program, the ERP has subsidised:

- 123 MW of solar PV
- 2.9 MW of wind
- 0.02 MW of fuel cells (CEC 2010a, 2010b).

Iltron (2010) stated that the capacity factor of these sources is 17 per cent for solar and wind, and 51 per cent for fuel cell generation. Using these capacity factors, the annual generation of the subsidised sources was estimated to be:

- 184 GWh from solar PV

- 4.3 GWh from wind
- 0.1 GWh from fuel cells
- 189 GWh of total generation.

Summary

Based on the Commission's sensitivity analysis, the estimates of the subsidy equivalent for the ERP for 2010 vary from US$30 million to US$57 million (A$33 million to A$62 million) (table K.25).

Table K.25 **Summary, Emerging Renewables Program**
California, 2010

Scenario	*Subsidy equivalent*		*Solar generation*	*Non-solar generation*
	A$m	US$m	GWh	GWh
'Central'	47	43	184	4
Low discount rate	33	30	184	4
High discount rate	62	57	184	4

Source: Productivity Commission estimates.

K.13 Summary, Californian capital subsidies

This section combines the estimates for the four Californian capital subsidies (the CSI, NSHP, SGIP and ERP) to estimate a combined subsidy equivalent, abatement and implicit abatement subsidy covering these schemes.

The subsidy equivalent

The subsidy equivalent for the Californian capital subsidies was estimated by simply adding up the four policy subsidy equivalents. This give a figure of between US$186 million and US$269 million (A$202 million and A$292 million) respectively, with a 'central' estimate of US$225 million (A$244 million) (table K.26).

Table K.26 **Subsidy equivalent, California capital subsidies**
California, 2010

	'Central'	*High*	*Low*	*'Central'*	*High*	*Low*
	A$m	A$m	A$m	US$m	US$m	US$m
The California Solar Initiative	136	148	125	125	136	115
New Solar Homes Project	3	4	2	3	4	2
Self Generation Incentive Program	59	78	42	54	72	39
Emerging Renewables Program	46	62	33	43	57	30
Total	**244**	**292**	**202**	**225**	**269**	**186**

Source: Productivity Commission estimates.

Abatement

The abatement for the California capital subsidies was estimated by multiplying the total generation 'induced' by the schemes by a counterfactual emissions intensity value.

In the case of the Californian capital subsidies, only the solar generation covered is relevant for the abatement estimates. This is because the other generation sources covered by these schemes (such as biomass, wind and fuel cells) are likely to be covered under one of the federal schemes analysed. While these sources receive an additional subsidy under the Californian schemes, they are not leading to any additional abatement.

The scheme covered 1.1 TWh of annual solar PV generation. The relevant counterfactual is the counterfactual emissions intensity of the Californian grid, which was assumed to be 0.406t CO_2/MWh. Therefore, the abatement attributed to the Californian schemes is estimated to be 449 kt CO_2.

Alternatively, according to Linn (2011), using this emissions intensity may understate the actual counterfactual emissions intensity. This is because solar may be displacing less efficient, and thus more emissions-intensive gas-fired generation. As such, an alternative emissions intensity of 0.6t CO_2/MWh was used for sensitivity analysis. This results in an abatement estimate of 663 kt.

The implicit abatement subsidy

Using the estimates outlined above, the implicit abatement subsidy for the Californian capital subsidies was estimated to be between US$280 and US$599/t CO_2 (A$305 and A$651), with a 'central' estimate of US$500/t CO_2 (A$544).

K.14 Summary

This section sets out the Commission's estimate of the total subsidy equivalent and abatement attributable to the seven US electricity generation policies. These policies represent only a sub-set of the emissions reduction policies in place at federal and state levels in the US. The Commission has attempted to focus on the policies that are likely to be having the largest effects on emissions. However, time and data constraints mean that there may be other policies that are contributing material abatement or subsidies to low-emissions generation.

The total subsidy equivalent

The subsidy equivalent estimates represent the effective subsidy granted to low-emissions generation from each scheme. These can be added up, to provide an estimate of the total subsidy equivalent for the policies analysed in the US electricity generation sector.

This was estimated at between US$2.7 billion and US$3.1 billion (A$2.9 billion and A$3.3 billion) (table K.27). This estimate is around 0.02 per cent of US GDP.

Table K.27 **Total subsidy equivalent**
United States, 2010

	Australian Dollars			*US Dollars*		
Policy	*'Central'*	*High*	*Low*	*'Central'*	*High*	*Low*
	A$m	A$m	A$m	US$m	US$m	US$m
Federal policies and state RPSs						
Renewable Electricity Production Tax Credits	1 708	1 708	1 708	1 571	1 571	1 571
Treasury Grants	588	782	418	541	719	385
Renewable Portfolio Standards	557	557	557	507	507	507
Californian schemes						
California Solar Initiative	136	148	125	125	136	115
New Solar Homes	3	4	2	3	4	2
Self-Generation Incentive Program	59	78	42	54	72	39
Emerging Renewables Program	46	62	33	43	57	30
Total	**3 097**	**3 339**	**2 886**	**2 848**	**3 071**	**2 654**

Source: Productivity Commission estimates.

Total abatement

Policy overlaps were described in section K.3. Taking into account these overlaps, the abatement estimates from these policies were added together to provide an estimate for the total abatement in the United States. This was estimated to be between 66 Mt CO_2 and 67 Mt CO_2 (table K.28). This is around 2.8–2.9 per cent of US counterfactual emissions from electricity in 2009.

Table K.28 **Total abatement**
United States, 2010

	Central	*High*	*Low*
	Mt CO_2	Mt CO_2	Mt CO_2
Federal policies and state RPSs	66	66	66
Californian solar subsidies	0.5	0.7	0.5
Total	**66**	**67**	**66**

Source: Productivity Commission estimates.

The average implicit abatement subsidy

Using the estimates outlined above, the Commission estimated an average implicit abatement subsidy for the US electricity sector of between US$39.80 and US$46.20/t CO_2 (A$43.27 and A$50.23) (table K.29).

The estimates of the average implicit abatement subsidy are relatively low compared to other countries. The reason for this is that the estimates of the total subsidy equivalent and total abatement are dominated by two policies: the Renewable Electricity Production Tax Credits and the Treasury Grants. These two federal programs provide significant subsidies to renewables. However, it is likely that some of the policies that the Commission has not analysed provide additional subsidies. For example, many states provide tax incentives for renewable energy generators. Omitting these policies from the analysis would tend to lead to lower estimates of the total subsidy equivalent and implicit abatement subsidy. It is likely that a more detailed analysis of the US electricity generation sector that covered all state-level policies would result in a higher estimate of both. As such, the Commission's estimates should be interpreted as a lower bound estimate of the total subsidy equivalent and implicit abatement subsidy.

Table K.29 **Average implicit abatement subsidy**
United States, 2010

		Total abatement					
		Australian Dollars			*US Dollars*		
		High	*'Central'*	*Low*	*High*	*'Central'*	*Low*
		A$/t CO_2	A$/t CO_2	A$/t CO_2	US$/t CO_2	US$/t CO_2	US$/t CO_2
Total subsidy equivalent	High	50.07	50.23	50.23	46.05	46.20	46.20
	'Central'	46.44	46.59	46.59	42.71	42.85	42.85
	Low	43.27	43.41	43.41	39.80	39.93	39.93

Source: Productivity Commission estimates.

K.15 Other US policies

The policies included in the Commission's estimates represent a subset of US policies targeted at the electricity generation sector that are likely to have the largest impact on the electricity generation sector, both in terms of abatement and subsidies provided. However, a number of policies were excluded from the analysis, either due to immateriality or lack of data. In addition, the United States is introducing a number of other policies that may have an impact on the US estimates in the future.

Excluded policies

Time and data constraints meant that the Commission had to exclude some policies from its analysis. A number of policies were excluded on the grounds that they were not likely to be material, relative to the other policies analysed. In particular, state-based schemes, aside from those in California and the renewable portfolio standards, were not included in the analysis (this includes state-based feed-in tariff schemes — box K.3). While in aggregate these schemes may have an impact, the Commission also considers it likely that many of these schemes would overlap with the federal schemes estimated and the state-based renewable portfolio standards,. Thus, their inclusion would be unlikely to result in a large increase in estimated abatement in the United States. The effect of including these policies in the estimates would most likely be to increase the total subsidy equivalent and the implicit abatement subsidy.

Box K.3 **Feed-in tariffs**

Feed-in tariffs (FITs) for renewable energy exist in some US states, and at a Federal level (through the Renewable Energy Production Incentive — REPI). The Commission has not estimated a subsidy equivalent or abatement for these schemes because:

- the REPI is unlikely to be material — funding was US$5 million in 2008 and 2009, and zero in 2010
- state FITs are mainly commercial arrangements between large generators and small-scale generators that the utilities use to meet their RPS obligations
- the Californian FIT was excluded because the FIT paid to renewable generators is based on the cost of generation from a combined-cycle gas turbine plant. As such, the FIT does not offer a subsidy in excess of the cost of conventional electricity.
- one scheme — the Washington Renewable Energy Production Incentives — appears to offer FITs to renewable energy generators. However, the Commission was unable to access data on the amount of generation supported by the scheme, or total payments.

Sources: CPUC (2011), US Department of Energy (2009).

Federal-level schemes that were not considered material in comparison to the other schemes include the following:

- High Energy Cost Grant Program — grants for energy supply in rural areas, including for improvements in energy generation, transmission and distribution. Grants range from US$75 000 to US$5 million.
- Rural Energy for America Program — grants to agricultural producers and small rural businesses for renewable energy and energy efficiency improvements.
- Renewable Energy Deployment Grants — 50 per cent grant for the construction of small renewable energy projects.
- Modified Accelerated Cost-Recovery System — depreciation deductions for businesses that invest in renewable energy technologies.
- Nuclear Power Production Tax Credit — tax credit of US$0.018/kWh for 6000 MW of nuclear energy. At the time of writing, the credit does not appear to have been used as yet.
- Public Utility Regulatory Policies Act — electricity from renewables must be purchased at avoided cost rates.
- Green Power Purchasing — new federal Government buildings must use a certain proportion of renewable energy ‘to the extent it is economically feasible’.
- Loans Guarantee Program (box K.4) — offers loan guarantees to clean energy technologies. Under this scheme, firms generally pay the credit subsidy (the

expected default risk to the government). However, under a scheme introduced as part of the American Recovery and Reinvestment Act, the government pays the credit subsidy.

In addition to the above, there are some policies that were excluded from the analysis because the necessary data were not available. These include:

- Clean Coal Investment Tax Credits
- CO_2 Capture and Sequestration Tax Credits
- Business Energy Investment Tax Credits
- Residential Renewable Energy Tax Credits.

Clean Coal Investment Tax Credits

In the 2005 Energy Policy Act (US), the US Government announced US$1.3 billion to subsidise 'clean coal' generation. Under this program, integrated-gasification combined-cycle coal plants can receive a 20 per cent investment tax credit, and other advanced coal technologies can receive a 15 per cent credit. An additional US$1.3 billion was announced in 2008, with the credit increased to 30 per cent where 65 per cent of CO_2 was sequestered.

According to the Office of Management and Budget (OMB 2009; 2010; 2011), an estimated US$450 million had been paid out under this scheme by the end of 2010. Using the standard approach to estimate the cost of capital subsidies (with a 7 per cent discount rate and economic lifetime of 35 years), this would result in a subsidy equivalent estimate of US$42 million per year (A$46 million).

However, little information was available on the plants that this subsidy funded, their generation, and thus the abatement induced by this scheme. Indeed, it is not known whether the subsidised plants were in operation as of the end of 2010. As such, this scheme has not been included in the estimates.

CO_2 Capture and Sequestration Tax Credits

The US carbon dioxide capture and sequestration tax credit provides a subsidy for each tonne of carbon dioxide (that would otherwise be released into the atmosphere) captured from an industrial facility and sequestered. In 2010, the credit was:

- US$20.24/t CO_2 sequestered, that is not used as a tertiary injectant in an oil or gas recovery project
- US$10.12/t CO_2 for carbon dioxide used as a tertiary injectant.

According to OMB (2011), in 2010 the estimated budgetary cost of the CO_2 sequestration credit was US$20 million — implying that between 1 MT–2 MT of CO_2 was sequestered. However, data were not available on how much of this occurred within the electricity generation sector, and as such this scheme has not been included in the estimates.

Box K.4 Subsidy equivalent, Loan Guarantee Scheme

Under the loan guarantee scheme introduced as part of the American Recovery and Reinvestment Act (US), government pays a credit subsidy (the expected default risk to the government) for guaranteed loans. This entails a subsidy to the guaranteed projects. Receiving a loan guarantee does not exclude a project from receiving other federal government incentives, such as Production Tax Credits.

While a subsidy equivalent for 2010 for this scheme can be estimated, abatement — and therefore an implicit abatement subsidy, for 2010 was not estimated. The reason is that while firms received the loan guarantees in 2010, none of the subsidised generators had finished construction in 2010, and therefore the actual abatement in 2010 would be zero. As such, this scheme was not included in the estimates.

Estimating the subsidy equivalent

According to the Loan Programs Office (LPO 2011), five renewable electricity projects were supported in 2010. US$3 billion of loans were guaranteed from these five projects.

An estimate of the 2010 credit subsidy rate of 14.53 per cent is provided in the 2011 US Government budget (OMB 2011, p. 440). Therefore, the estimated value of the credit subsidy is US$442 million (A$480 million).

As this is an up-front subsidy, this value was annualised using the same approach as for capital subsidies. Using a discount rate of 7 per cent, and an expected economic lifetime of the assets of 20 years, the subsidy equivalent is estimated as A$45 million per year (US$42 million).

As there was no abatement in 2010, the Loan Programs Office estimated that, once complete, the projects will result in annual generation of 3.3 TWh, and annual CO_2 abatement of 2 Mt CO_2. This implies an implicit abatement subsidy, once all projects are fully operational, of between A$16 and A$30/t CO_2 (provided they are not receiving any other subsidies).

Source: LPO (2011).

Business Energy Investment Tax Credits (ITC)

The ITC offers a tax credit for 30 per cent of expenditures for commercial, industrial and agricultural capital investments in solar, small fuel cells and small wind turbines (up to 100 kW capacity) and a tax credit of 10 per cent of expenditures for capital investments in geothermal systems, microturbines and CHP (IRS (US) 2010a).

Due to data constraints, the Commission was unable to estimate the implicit abatement subsidy of the ITC. However, this was not considered to have a material effect on the Commission's aggregate estimates for the United States. In particular, the value of the ITC in 2010 is considered to be small relative to the size of the Treasury Grants and PTC in 2010. The OMB provided an estimate of the value of the ITC tax expenditure in the 2010 fiscal year of $US270 million (OMB (US) 2010).

Residential Renewable Energy Tax Credits (RTC)

The RTC was introduced in 2005 and provides a 30 per cent tax credit for eligible renewable energy technologies installed in residential dwellings. The tax credit is provided for solar hot water, solar photovoltaic, small wind, fuel cells, and geothermal heat pumps. The RTC is similar in operation to the ITC for commercial and industrial renewable energy operators.

The Commission was unable to obtain data or estimates on the value of the foregone revenue for the RTC or the amount or source of residential renewable electricity supported by the scheme. As a result, the Commission was unable to estimate the subsidy equivalent or abatement of the RTC.

Committed policies

The Commission identified two policies that have been committed to by state and federal government in the United States that have the potential to deliver significant emissions reductions in the future.

EPA Greenhouse Gas Regulations

The US Environmental Protection Agency has scheduled that from 2011, fossil fuel power plants will be subject to emissions standards. It appears that plants will be required to meet emissions limits using the 'best available technology'. However, there is much uncertainty over the form these standards could take.

Western Climate Initiative (WCI)

The Western Climate Initiative (WCI) is an agreement between seven US states and four Canadian provinces to implement a cap-and-trade emissions trading scheme. At this stage, it appears that only California is fully committed to implementing an emissions trading scheme by 2012 (chapter 2).

The WCI aims to reduce emissions to 15 per cent below 2005 levels by 2020. Electricity and large industrial facilities are scheduled to be covered by the ETS in 2012, with the scheme expanding to include transport and other fuels in 2015 (WCI 2010).

The WCI has recommended that the 2012 cap be the same as projected 2012 emissions (WCI 2010). Therefore, it is likely that the permit price and abatement will be close to zero. The cap will tighten over time, and it would be expected that the permit price will rise as the scheme progresses.

The California Air Resources Board (CARB 2010) modelled the Californian emissions trading scheme for 2020. Their estimates of the 2020 permit price ranged from US$25/t CO_2-e to US$162/t CO_2-e — depending on the extent to which complementary policies remained in place. Modelling by the WCI (2010) suggested a permit price of between US$13/t CO_2-e and US$50/t CO_2-e in 2020 (2007 US$) for the WCI as a whole.