L Demand-side analysis for electricity

Previous sections of this report have quantified the extent to which policies lead to supply-side abatement in the electricity sector (abatement due to generators shifting to less emissions-intensive technologies). Emissions-reduction policies can also lead to demand-side abatement by electricity consumers (abatement due to lower electricity consumption) if the policy raises electricity prices.[1]

Given data and other constraints (discussed below), the Commission was not able to precisely quantify the extent to which policies increase electricity prices and thereby lead to demand-side abatement. Instead, this appendix presents illustrative estimates of demand-side abatement based on a number of simplifying assumptions. The consumption cost — defined as the consumer valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure — is also illustrated by using simplifying assumptions.

The broad approach used to quantify demand-side abatement is outlined in box L.1. A critical input to the calculations was the own-price elasticity of electricity demand (box L.2). In summary, two alternative elasticities were used — -0.2 and -0.7 — to estimate the range within which demand responses seem most likely to occur, given the empirical evidence on elasticities.

The resulting estimates should be considered illustrative, or at best only indicative, rather than being a definitive assessment of demand-side abatement and final consumer-price impacts. This is because it was necessary to make various simplifying assumptions to complete the task within the time and data constraints faced by the study. These include the following.

- It was assumed that the cost borne by electricity generators due to emissions-reduction policies was passed through the value chain and ultimately on to consumers, unless it was clear that the policy was explicitly funded by taxpayers. This provides an upper-bound estimate of the actual increase in electricity prices, since no account was taken of factors — such as retail-price

[1] Demand-side abatement can also result from policies that encourage consumers to increase their energy efficiency at a given electricity price. As noted in chapter 3, energy efficiency policies are not included in this study's quantitative analysis due to uncertainty about their impacts.

regulation and competitive pressures — that can limit producers' scope to pass cost increases on to their customers.

- Differences in policy coverage and electricity prices between different groups of customers — such as residential, commercial and industrial — were factored into the calculations where possible. However, the resulting estimates are unlikely to be as accurate as those generated by industry models that more accurately capture differences between customer groups, including their responsiveness to price changes.
- No account was taken of the compensation that governments sometimes provide to consumers to cushion the price impacts of emissions-reduction policies. Thus, the estimates could overstate the reduction in electricity demand, associated demand-side abatement, and consumption costs.
- For a given country, it was common for one or more variables used in the calculations to be unavailable for the same year as the estimated total subsidy equivalent. In such cases, a mixture of data for adjacent years had to be used. Data constraints also led to inconsistent time periods across countries. Thus, the estimates should only be viewed as being illustrative of recent impacts, rather than a precise quantification of those in a specific year.

The supply-side estimates presented earlier in this report excluded subsidies that do not induce abatement. This was necessary in order to approximate the resource cost of abating emissions. In contrast, the demand-side estimates presented here include all subsidy equivalents associated with a given policy, regardless of whether any abatement is induced. This is done on the grounds that, while no abatement may be achieved, there is a cost and, if it is not explicitly funded by taxpayers, it will be passed on to consumers as higher electricity prices.[2]

2 The cost of levying taxes to fund the administration of emissions-reduction policies, and to finance taxpayer-funded abatement subsidies, could be passed on to electricity consumers through means other than electricity prices. The Commission has not estimated this in its demand-side analysis.

Box L.1 **Quantifying demand-side abatement for electricity**

The Commission sought to quantify the extent to which emissions-reduction policies increase the price of electricity, and thereby reduce electricity consumption and induce demand-side abatement. The net cost to consumers was also estimated.

In a small number of cases, the price uplift resulting from an emissions-reduction policy had been estimated in a previous study. Such estimates were used where appropriate.

In other cases, it was necessary to estimate the price uplift. To simplify this task, it was assumed that electricity generators pass the full cost of abatement policies on to consumers, unless the policy is explicitly funded by taxpayers. On this basis, the policy-induced change in the electricity price (Δp) was estimated by the formula:

$$\Delta p = (\Sigma R + \Sigma SE)/q_1$$

where ΣR is the total revenue from explicit carbon prices; ΣSE is the subsidy equivalent for other policies, excluding any amounts explicitly funded by taxpayers; and q_1 is (observed) electricity output with the abatement policies in place.

This provided an upper-bound estimate of the actual increase in the electricity price, since no account was taken of factors — such as retail-price regulation and competitive pressures — that can limit producers' scope to pass cost increases on to customers.

The reduction in electricity consumption (Δq) will be:

$$\Delta q = q_0 \left[\varepsilon \left(\frac{\Delta p}{p_0} \right) \right]$$

where q_0 is electricity consumption *without* the abatement policies; p_0 is the electricity price *without* the policies; and ε is the own-price elasticity of demand for electricity (a measure of consumers' responsiveness to price changes, defined in box L.2).

However, q_0 is not observed, and so it is necessary to re-express the above formula in terms of observed consumption (q_1) using the fact that $q_0 = q_1 - \Delta q$ and $p_o = p_1 - \Delta p$:

$$\Delta q = \frac{q_1 \varepsilon \, \Delta p}{p_1 - \Delta p(1-\varepsilon)}$$

where p_1 is the (observed) electricity price *with* the emissions-reduction policies.

Demand-side abatement of emissions (Δe) was estimated by the formula:

$$\Delta e = a.\Delta q$$

where a is the emissions intensity associated with the output change Δq.

The consumption cost — defined as the consumer valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure — was approximated by:

$$\tfrac{1}{2}\Delta p \Delta q$$

using the assumption that the demand curve is linear and supply is perfectly elastic.

Box L.2 **Own-price elasticity of demand for electricity**

The own-price elasticity of electricity demand measures the proportional change in electricity consumption in response to a unit change in the price. It is usually negative, since a price increase will typically reduce consumption. Thus, an elasticity of -0.5 indicates that a 1 per cent rise in the electricity price reduces demand by 0.5 per cent.

The elasticity also tends to be lower in the short term than in the long term, because it takes time for consumers to substitute towards less energy-intensive appliances.

A recent cross-country review of elasticity estimates for electricity demand found that they typically range from -0.2 to -0.4 in the short term, and -0.5 to -0.7 in the long term (Fan and Hyndman 2011). The review also concluded that there was no obvious evidence of significant differences in elasticities between the commercial, residential and industrial sectors. A sample of the reviewed estimates is provided below.

	NIEIR	*Taylor et al.*	*King*	*Reiss*	*Bohi and Zimmerman*	*Beenstock et al.*
Year	2007	2005	2003	2005	1984	1999
Location	Australia	UK	California	California	US	Israel
Residential	-0.25	..	-0.3	-0.39	-0.2 (ST) -0.7 (LT)	-0.21 to -0.58
Commercial	-0.35	..	..	..	..	..
Industrial	-0.38	-0.05 to -0.26	..	..	..	-0.002 to -0.44

ST short term. **LT** long term. **..** Not applicable.

The OECD published a similar review of price elasticity estimates for residential energy demand, which includes space heating, water heating and household electricity consumption. It concluded that there 'is some consensus on the short-run price elasticity [for residential energy demand] being about -0.3' and the 'long-run price elasticity could be -0.7' (Kristrom 2008, p. 108).

Within Australia, the energy-market operator (AEMO 2010a) has used elasticities that range from -0.16 to -0.38 when analysing the electricity market.

Given that there is a range of elasticity estimates within Australia and across countries, the Commission concluded that it would be inappropriate to use a single value in its calculations. Instead, two alternative elasticities were used: -0.2 and -0.7. This provided a range within which the true demand response seems most likely to occur, given the empirical evidence on elasticities.

L.1 Australia

The impact of emissions-reduction policies on retail electricity prices has been a prominent issue in recent debate about Australia's actions to address climate change, and may continue to be so under current regulatory arrangements (Sims 2010). For example, the NSW regulator (IPART 2011a) recently issued a draft decision that would allow retailers to raise regulated tariffs by around 18 per cent on 1 July 2011. Most of this increase (10 per cent) was to cover a rise in network costs (transmission and distribution of electricity). However, much of the remaining increase (6 per cent) was to cover the cost of recent changes to the Renewable Energy Target (RET).[3] This would be in addition to the cost previously allowed for the pre-existing RET, which MMA (2010) estimated would have raised retail electricity prices by around 4 per cent at a national level over 2010–2015.[4] Feed-in tariffs (FITs) and other emissions-reduction policies — such as the NSW Greenhouse Gas Reduction Scheme (GGAS) — have also been argued to have contributed to the growth of electricity prices in recent years (Garnaut 2011).

Analysed policies

The Commission analysed four Australian policies for their demand-side impacts — the (expanded) RET that existed up until the end of 2010, state and territory solar FITs, the Queensland Gas Scheme (QGS), and GGAS. A more detailed description of each of these policies is provided in the analysis of Australian supply-side abatement in appendix D.

The combined carbon-price revenues and subsidy equivalents for the four policies was estimated to be in the range of A$668–845 million per annum. Of this, around A$463–640 million was attributed to the (expanded) RET.

The estimates for the RET take account of the different prices received by small and large-scale generators for renewable energy certificates (RECs) in 2010, and the surplus of RECs in that year.

- For large-scale generators, the lowest and highest subsidy equivalents from the supply-side analysis were used — A$283 million using a lower-bound REC price of A$37.03 and A$459 million using an upper-bound REC price of

3 About a month after IPART released its draft decision, the Australian Government (Combet and Dreyfus 2011) announced adjustments to the 'solar credits' used for the small-scale component of the RET, which it claimed would reduce the cost to electricity users by around half in 2012.

4 MMA (2010) estimated that, if the RET that applied in 2010 had remained unchanged, it would have increased retail electricity prices by 4.0 per cent over 2010–2015 if the Carbon Pollution Reduction Scheme (CPRS) had started in 2013, and 4.2 per cent if the CPRS started in 2014.

A$60 respectively. These estimates assume that all 7.6 million RECs created by large-scale generators in 2010 were surrendered to meet the RET target in that year.

- The RET required 12.5 million RECs to be surrendered in 2010 (ORER 2011b). If 7.6 million of these RECS were created by large-scale generators, the remaining 4.9 million RECs had to be created by small-scale generators. Multiplying 4.9 million by the average spot-market price for RECs in 2010 (A$37.03) resulted in an amount of A$181 million for small-scale generators.[5]
- The A$181 million estimate used here for small-scale generators differs from the range of subsidy equivalents estimated in this study's supply-side analysis (A$52–98 million, depending on assumptions) for two reasons. First, the supply-side estimate was based on the number of RECs created in 2010 (28.6 million, excluding RECs for solar water heaters), which was much greater than the 12.5 million RECs that retailers and other large electricity purchasers had to surrender in that year (surplus RECs can be carried over to be surrendered in a later year). Second, the supply-side analysis converted the subsidy for small-scale renewable generators into an annualised figure to reflect the fact that the subsidy was effectively an upfront payment for abatement over several years. Here, it is assumed that the cost that retailers and other large electricity purchasers incur in obtaining a REC is passed on to consumers in the year that it is incurred.

For FITs and QGS, the subsidy equivalents estimated in this study's analysis of supply-side abatement were used (A$96 million and A$38 million respectively).

For GGAS, the Commission estimated that only about 4 per cent of NSW Greenhouse Abatement Certificates (0.6 million out of 15.5 million certificates in 2009) were for abatement that would not otherwise have occurred. Thus, the amount used here to quantify demand-side abatement — A$71 million — is greater than the subsidy equivalent reported in the supply-side analysis (A$3 million).

Australian retail prices

Another key input to the estimation of demand-side abatement was the retail price currently paid by consumers (which is distinct from the wholesale prices used in this report to analyse supply-side abatement). Like other countries, retail electricity prices in Australia vary between customer types (such as households and industry), jurisdictions, retailers within a given state or territory, and according to the level of

5 As noted in the supply-side analysis (appendix D), the Commission considers the spot-market price to be the most appropriate value to assign to RECs created by small-scale generators.

consumption. This issue could be addressed by calculating a weighted average price across all consumers, with weights being the share of total electricity demand subject to a given price. Such an approach was used for some of the other analysed countries, but it was not possible for Australia because the necessary data were not available.

Instead, the Commission based its Australian demand-side calculations on regulated and standing-offer tariffs offered to residential and small-business customers in each jurisdiction. This information is published regularly by the Office of the Tasmanian Economic Regulator (OTTER 2010) in monitoring reports that compare energy prices across the states and territories. To ascertain the range within which Australian demand-side abatement lies, the Commission used the minimum and maximum electricity prices reported by OTTER (2010) for representative residential and small-business consumers in August 2010. The prices were A$163/MWh and A$282/MWh.[6]

Estimation results and the RET

The Commission's demand-side estimates suggest that the analysed policies raised electricity prices in the range of 1.0–2.3 per cent (table L.1). The resulting emissions reductions were estimated to be in the range of 0.1–2.3 per cent, and the consumption cost in the range of A$0.7–6.9 million. It is possible that these national estimates conceal significant differences between states and territories.

The price increase estimated by the Commission at a national level for all analysed policies is less than the increase of around 4 per cent that MMA (2010) forecast for just the RET over 2010–2015. It appears that most of the difference can be explained by the REC and retail prices that MMA used in its calculations.

- MMA based its estimates on a REC price of around A$55–70 over 2010–2015, whereas the Commission used REC prices in the range of A$37–60.
- MMA estimated its percentage price change relative to an expected retail price of around A$115/MWh for 2010–2015, which was lower than the prices observed by OTTER (2010) and used by the Commission in its calculations (A$163/MWh and A$282/MWh).

6 In August 2010, residential prices, based on average consumption in the relevant state or territory, ranged from $163/MWh (ACT) to $262/MWh (NSW). Small-business prices, for consumption of 150 MWh/year, ranged from $184/MWh (Victoria) to $282/MWh (NSW) (OTTER 2010).

Table L.1 Estimated demand-side impacts of Australian emissions-reduction policies

	Units	Low estimate	High estimate
Inputs to calculations			
Carbon-price revenues and subsidy equivalents	A$m	668	845
Renewable Energy Target	A$m	463	640
Feed-in tariffs	A$m	96	96
Queensland Gas Scheme	A$m	38	38
Greenhouse Gas Reduction Scheme	A$m	71	71
Production[a]	TWh	230	230
Retail price[b]	A$/MWh	282	163
Emissions[c]	Mt CO_2	196	196
Emissions intensity of displaced output[d]	t CO_2/MWh	0.54	1.20
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	1.0	2.3
Change in electricity consumption	%	-0.2	-1.6
Change in emissions	%	-0.1	-2.3
Consumption cost:[e]			
total amount	A$m	0.7	6.9
per tonne of demand-side abatement[f]	A$/t CO_2	2.7	1.5

[a] Production in 2008-09 (ABARES 2011). [b] Highest and lowest prices in August 2009, based on a cross-state/territory comparison by OTTER (2010) of amounts paid by residential customers (at average consumption in the relevant state/territory) and small-business customers (using 150 MWh/year) on regulated and standing-offer contracts. The highest price is used to generate the 'low estimate' results (and vice versa) because it minimises (maximises) the proportionate price change from a given amount of carbon-price revenues and subsidy equivalents. [c] 2010 data from DCCEE (2011a). [d] Emissions intensities are the lowest (natural gas) and highest (brown coal) estimates reported in the analysis of supply-side abatement. [e] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [f] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: ABARES (2011); DCCEE (2011a); Frontier Economics (unpublished data); OTTER (2010); Productivity Commission estimates.

Using the same REC and retail prices as MMA, the Commission's approach would result in an estimated retail price increase of up to 3.4 per cent in 2010 for the RET alone, which is closer to MMA's results.

Recent changes to the RET are likely to mean that the price increases estimated by MMA are more representative of the RET's future impacts.[7] The RET scheme was changed significantly in January 2011 by splitting it into small and large-scale components. This was done in response to concerns that 'the inclusion of

[7] MMA (2010) estimated that, with the recent changes, the RET would raise retail electricity prices in the range of 4.2–4.4 per cent over 2010–2015.

small-scale technologies and their impact on the renewable energy certificate (REC) market [was] delaying investment in large-scale renewable energy projects' (Australian Government 2010, p. 6; ECALC 2010, p. 2). As noted previously, the number of RECs created in 2010 was far greater than what had to be surrendered in that year. This placed downward pressure on REC prices, to the extent that it raised concerns that the RET did not provide a sufficient incentive to invest in large-scale renewable generation (ECALC 2010). As noted above, IPART (2011a) has proposed a 6 per cent increase in NSW regulated tariffs to cover the cost of the changes made to the RET.[8]

L.2 China

Three of the Chinese policies covered in this study's analysis of supply-side abatement are taxpayer funded, and so are not expected to lead to demand-side abatement.[9] The remaining policies analysed here are the Jiangsu photovoltaic (PV) FITs; wind FITs and value-added tax (VAT) exemption; and biomass FITs. A more detailed description of each of these policies is provided in the analysis of Chinese supply-side abatement in appendix E.

The combined subsidy equivalents for the three policies was estimated to be in the range of CNY 16.5–17.0 billion. This amount was derived as follows.

- In the supply-side analysis, all output subsidised by the Jiangsu PV FITs was assumed to be induced by the policy. Thus, the estimated subsidy equivalent of CNY 516 million from the supply-side analysis can be used here.
- In the supply-side analysis, it was estimated that between 70 and 90 per cent of wind generation was induced by the wind FITs and VAT exemption. Including subsidies paid for generation not induced these policies leads to a subsidy equivalent of CNY 11 954 million.[10]

8 This is more than the average national increase in retail electricity prices that MMA (2010) estimated over 2010–2015 for the most recent version of the RET (4.2–4.4 per cent). Previous estimates by MMA (2009) suggest that the RET causes a higher percentage increase in retail electricity prices in New South Wales than in other states.

9 Large Substitute for Small program, subsidy for solar photovoltaic in buildings, and Golden Sun demonstration scheme.

10 In the supply-side analysis, a range of CNY 8368–10 759 million was estimated for the subsidy equivalent of the wind FITs and VAT exemption. The former figure assumed that 70 per cent of generation was additional and the latter 90 per cent. Adjusting each subsidy equivalent estimate up to include the subsidies paid to non-induced generation leads to the same amount of CNY 11 954 million.

- For the biomass FITs, the Commission estimated that 54 per cent of subsidised production was induced by the policy. Thus, the range used here — CNY 4061–4570 million — is greater than the subsidy equivalent reported in the supply-side analysis (CNY 2193–2468 million).

China currently has a levy of CNY 4/MWh on electricity consumers to help fund the cost of FITs. It could be argued that this should be the price uplift used here to analyse demand-side abatement. However, it would make little difference to the calculations in practice. The Commission's estimate of the price uplift from passing on the cost of the FITs subsidy equivalent was also around CNY 4/MWh.

Other inputs to the calculations were obtained from a range of sources. It was particularly difficult to obtain recent data on two key inputs to the demand-side calculations — total emissions and a retail electricity price. The approach used for these variables is outlined below.

Chinese emissions

An estimate of 2009 emissions was derived by scaling up reported 2005 emissions — 2115 Mt CO_2 according to Malla (2009) — by the percentage increase in electricity production from 2005 to 2009. According to EIA (2011k), Chinese electricity production increased by about 45 per cent from 2005 to 2009 (from 2370 TWh to 3446 TWh). On this basis, 2009 emissions were estimated to be 3075 Mt CO_2. The Commission acknowledges that this estimate overlooks any changes from 2005 to 2009 in the fuel mix used to generate electricity, and efficiency gains that have reduced the emissions intensity associated with specific fuels.[11] However, this did not have a major bearing on the estimated demand-side abatement because the subsidy equivalents associated with analysed policies are relatively insignificant (detailed below).

Chinese retail prices

Chinese retail electricity prices are largely determined at a central level by the National Development and Reform Commission (NDRC) (IEA 2010n). However, prices can vary between regions, including as a result of decisions made by local governments (IEA 2010n; Lan 2010). Moreover, it appears that retail electricity

[11] The Commission did, however, benchmark its approach against a 'bottoms-up' analysis of individual plants by CARMA (2007), which estimated that 2007 emissions were 2830 Mt CO_2 (3120 US (short) tons). Using the Commission's approach, scaling up 2005 emissions (2115 Mt CO_2 according to Malla 2009) by 2005–2007 output growth (28 per cent according to EIA 2011k) results in a similar estimate of around 2710 Mt CO_2 for 2007.

prices have often been set below the cost of production in recent years, particularly for coal-fired generators, leading to significant losses for many producers (China Securities Journal 2011; EIU 2011; Lan 2010). The NDRC recently proposed changing to a new tiered pricing system in which retail prices would rise with consumption. However, this was intended to encourage domestic consumers to save energy and reduce greenhouse gas emissions, rather than to eliminate the losses experienced by generators (China State Power 2010; IEA 2010n; Lan 2010; Shanghai Municipal Government 2010; Xinhua News Agency 2010a).

The current regulatory arrangements for Chinese electricity prices raise doubts about whether the cost of emissions-reduction policies is passed on to electricity consumers. For simplicity, it has been assumed here that electricity consumers do bear the cost of the analysed policies. However, the resulting estimates should be considered an upper bound on the actual change in electricity prices, abatement and consumption cost.

Low and high estimates of the Chinese retail electricity price — CNY 423/MWh and CNY 790/MWh — were used to place a range on demand-side abatement. These prices were based on data published by the State Electricity Regulatory Commission (SERC 2009), the official Chinese news service, and other sources.

- Xinhua News Agency (2010b) reported that, in December 2010, the retail price of electricity was about CNY 600/MWh. However, it was unclear whether this was an average across all regions and consumers.
- Data published by SERC (2009) indicate that the average residential electricity tariff in 2009 ranged from CNY 423/MWh in Hebei province to CNY 628/MWh in Guangdong province (SERC 2009).[12] Similarly, Lan (2010) reported a range of CNY 420/MWh in Qinghai to CNY 610/MWh in Guangdong.
- Xinhua News Agency (2009) reported that the residential tariff in Beijing was CNY 490/MWh. This was similar to the Beijing tariff of around CNY 480/MWh reported by Lan (2010) and Beijing International (2011), and CNY 473/MWh reported by SERC (2009).
- Chinese electricity prices are generally higher for non-residential customers. Xinhua News Agency (2009) reported that Beijing tariffs were around CNY 520/MWh for agricultural use, CNY 760/MWh for 'secondary industry',

[12] This excludes Qinghai and Inner Mongolia, which were the only provinces that SERC (2009) reported as having an average price below CNY 400/MWh. Those provinces collectively accounted for less than 3 per cent of China's population in 2009 (CNBS 2009). Guangdong was the only province to have a price over CNY 600/MWh, but it accounted for around 7 per cent of China's population.

and CNY 790/MWh for 'commercial use'. Yiyu (2010) reported that the industrial tariff was CNY 560/MWh in 2009.

While there is some uncertainty associated with the total emissions and retail prices used here for the demand-side calculations, this is unlikely to have a notable effect on the results. As can be seen in table L.2, the estimated electricity-price increase (and hence emissions reduction and consumption cost) due to emissions-reduction policies is relatively small in percentage terms. This is due to the subsidy equivalents associated with the analysed policies being relatively insignificant when spread across all output.

Table L.2 **Estimated demand-side impacts of Chinese emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Carbon-price revenues and subsidy equivalents	CNY m	16 531	17 040
Jiangsu PV FITs	CNY m	516	516
Wind FITs and VAT exemption	CNY m	11 954	11 954
Biomass FITs	CNY m	4 061	4 570
Production[a]	TWh	3 446	3 446
Retail price[b]	CNY/MWh	790	423
Emissions[c]	Mt CO_2	3 075	3 075
Emissions intensity of displaced output[d]	t CO_2 /MWh	0.8042	1.003
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	0.6	1.2
Change in electricity consumption	%	-0.1	-0.8
Change in emissions	%	-0.1	-0.9
Consumption cost:[e]			
total amount	CNY m	10.1	71.1
per tonne of demand-side abatement[f]	CNY/t CO_2	3.0	2.5

[a] Electricity production in 2009 (EIA 2011k). [b] Range of retail prices reported by SERC (2009) and Xinhua News Agency (2009), as described in the main text. The highest price is used to generate the 'low estimate' results (and vice versa) because it minimises (maximises) the proportionate price change from a given amount of carbon-price revenues and subsidy equivalents. [c] 2009 emissions. Estimated by indexing up 2005 estimate of 2115 Mt from Malla (2009) by the percentage growth in output over 2005–2009 (output rose from 2370 TWh to 3446 TWh, an increase of around 45 per cent, according to EIA 2011k). [d] Emissions intensities are the lowest (new coal plants) and highest (national average 'operating margin' Clean Development Mechanism (CDM) projects) estimates used in this report's analysis of supply-side abatement. [e] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [f] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: EIA (2011k); Malla (2009); SERC (2009); Xinhua News Agency (2009); Productivity Commission estimates.

L.3 Germany

Three German policies were analysed for their demand-side impacts — the EU emissions trading scheme (ETS), Renewable Energy Sources Act (RES Act), and Combined Heat and Power Act (CHP Act). A more detailed description of each of these policies is provided in the analysis of German supply-side abatement in appendix F.

The combined carbon-price revenues and subsidy equivalents for the three policies was estimated to be in the range of €10 171–11 462 million. This range was derived as follows.

- The European Union ETS imposes an explicit carbon price on emissions. The revenue raised from the German electricity sector was estimated by multiplying an average permit price — €13.60 for April 2009 to March 2010 — by the number of permits required to cover 2009 electricity-sector emissions of 299 Mt CO_2. The resulting estimate was €4066 million.
- All renewable electricity generated in Germany was assumed to be induced by the RES Act feed-in tariffs. As a result, the estimated subsidy equivalent from the supply-side analysis was used here. This ranged from a low estimate of €5616 million to a high of €6832 million.
- The Commission concluded that only 57 per cent of electricity generation receiving CHP Act payments had been induced by the policy. Thus, the amount used here — €489 million — is greater than the subsidy equivalent estimated in the supply-side analysis (€279 million).

Data for other inputs to the calculations, such as electricity generation and prices, were sourced from Frontier Economics and Eurostat, as detailed in table L.3 below. The resulting estimates suggest that the analysed policies increased German electricity prices in the range of 12–14 per cent, and reduced emissions by between 3–19 per cent.

Table L.3 **Estimated demand-side impacts of German emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Carbon-price revenues and subsidy equivalents	€m	10 171	11 462
European Union ETS	€m	4 066	4 066
Renewable Energy Sources Act	€m	5 616	6 907
Combined Heat and Power Act	€m	489	489
Production[a]	TWh	593	593
Retail price[b]	€/MWh	156	156
Emissions[c]	Mt CO_2	299	299
Emissions intensity of displaced output[d]	t CO_2/MWh	0.53	1.09
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	12	14
Change in electricity consumption	%	-2	-10
Change in emissions	%	-3	-19
Consumption cost:[e]			
total amount	€m	128	628
per tonne of demand-side abatement[f]	€/t CO_2	16	9

[a] Electricity production in 2009 (Frontier Economics, unpublished data). [b] Average of second-half 2009 retail prices for households (€229/MWh) and industry (€113/MWh) (Eurostat 2010), weighted by the share of each in final electricity demand (37 and 63 per cent respectively in 2008, based on Eurostat (2010) data on final energy consumption). [c] 2009 data from Frontier Economics (unpublished data). [d] Emissions intensities are the lowest (natural gas) and highest (lignite) estimates used in this report's analysis of supply-side abatement. [e] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [f] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: Eurostat (2010); Frontier Economics (unpublished data); Productivity Commission estimates.

L.4 Japan

Two of the Japanese policies covered in the analysis of supply-side abatement are taxpayer funded (appendix G), and so are not expected to lead to demand-side abatement.[13] The remaining policies analysed here are the Renewable Portfolio Standard, New Buyback Program for Solar Photovoltaic, and petroleum and coal tax. The combined carbon-price revenues and subsidy equivalents for these policies was estimated to be around ¥216 billion per annum. This was derived as follows.

[13] Policies excluded from the demand-side calculations are the national solar photovoltaic capital subsidies, and Tokyo solar photovoltaic capital subsidies.

- For the Renewable Portfolio Standard, the Commission assumed in its supply-side analysis that around 53 per cent of subsidised output was induced by the policy (4.6TWh out of 8.61TWh of subsidised output). Thus, the amount used here — ¥44 547 million — is greater than the subsidy equivalent estimated in the supply-side analysis (¥23 800 million).
- The New Buyback Program for Solar Photovoltaic has only been in place since November 2009. For this reason, the supply-side analysis only estimated a subsidy equivalent for the five-month period from 1 November 2009 to 31 March 2010 (¥6022 million). In contrast, the demand-side analysis here is based on an annualised estimate of the subsidy equivalent — ¥14 453 million — on the grounds that the policy is ongoing, and to ensure consistency with the annual amounts used for the other policies.
- Revenue raised by the petroleum and coal tax was derived by multiplying fuel-specific tax rates (estimated in the supply-side analysis) by the electricity generated by the relevant fuel.[14] This resulted in total tax revenue of ¥156 780 million.

Data for other inputs to the calculations, such as electricity production and retail prices, were sourced from the International Energy Agency (IEA) and United Nations Framework Convention on Climate Change (UNFCCC), as detailed in table L.4 below. The resulting estimates suggest that the analysed policies have a relatively small impact on Japanese electricity prices, and hence electricity consumption, emissions and consumption costs.

[14] The estimated tax rates were ¥0.16/kWh for gas-fired generation, ¥0.24/kWh for coal and ¥0.47/kWh for oil. In 2009, electricity generated from coal was 295 TWh, from gas 273 TWh, and from oil 90 TWh (IEA 2010d).

Table L.4 **Estimated demand-side impacts of Japanese emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Carbon-price revenues and subsidy equivalents	¥m	215 780	215 780
Renewable Portfolio Standard	¥m	44 547	44 547
New Buyback Program for Solar Photovoltaic[a]	¥m	14 453	14 453
Petroleum and Coal Tax	¥m	156 780	156 780
Production[b]	TWh	1 046	1 046
Retail price[c]	¥/MWh	21 300	14 760
Emissions[d]	Mt CO_2	396	396
Emissions intensity of displaced output[e]	t CO_2/MWh	0.439	0.574
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	1.0	1.4
Change in electricity consumption	%	-0.2	-1.0
Change in emissions	%	-0.2	-1.5
Consumption cost:[f]			
total amount	¥m	211	1 081
per tonne of demand-side abatement[g]	¥/t CO_2	235	180

[a] Annualised estimate based on the subsidy equivalent of ¥6022 million estimated in this study's supply-side analysis for the five-month period from 1 November 2009 to 31 March 2010. [b] Electricity production in 2009 (IEA 2010d). [c] Average 2009 price reported by IEA (2010g) for residential customers (¥21 300/MWh) and industry (¥14 760/MWh). The highest price is used to generate the 'low estimate' results (and vice versa) because it minimises (maximises) the proportionate price change from a given amount of carbon-price revenues and subsidy equivalents. [d] 2008 data for electricity and heat sectors from UNFCCC (2011b). [e] Emissions intensities are those used for gas-fired (0.439 t CO_2/MWh) and oil-fired (0.574 t CO_2/MWh) generation in this report's analysis of supply-side abatement. [f] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [g] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: IEA (2010d, 2010g); UNFCCC (2011b); Productivity Commission estimates.

L.5 New Zealand

The key emissions-reduction policy affecting the electricity-generation sector is the New Zealand ETS, which has covered electricity generation since July 2010. While some industries have received free emissions permits to compensate for the impact of the ETS on asset values and competitiveness, this does not include electricity generators. The NZ Government has stated that free permits were not warranted for the energy sector because it is able to pass the cost of the ETS on to customers (NZME 2010).

Prior to its introduction, NZME (NZ Government) (2010) estimated that the ETS would raise electricity prices by NZ$0.01/kWh (NZ$10/MWh), or around 5 per cent for households. It was not stated whether this was the longer-term impact, or that expected in the short term while the ETS was being phased in. However, the Ministry for the Environment (NZ) (pers. comm., 23 May 2011) advised the Commission that 'the latter is more correct'. A transitional period applies until the end of 2012, during which the cost of the ETS is effectively capped at NZ$12.50/t CO_2-e emitted (NZME 2011c).

Given a permit price of NZ$12.50 per tonne and electricity-sector emissions of around 6 Mt CO_2 (2009 data reported by NZME 2011d), the ETS would raise about NZ$74 million from the electricity-generation sector. If all of this was passed on to electricity consumers, the Commission's illustrative estimates suggest that it would raise electricity prices by around 0.7–1.6 per cent for all consumers (table L.5).

Table L.5 **Estimated demand-side impacts of New Zealand emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Carbon-price revenues			
New Zealand ETS[a]	NZ$m	74	74
Production[b]	TWh	43	43
Retail price[c]	NZ$/MWh	243	111
Emissions[d]	Mt CO_2	6	6
Emissions intensity of displaced output[e]	t CO_2/MWh	0.52	0.52
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	0.7	1.6
Change in electricity consumption	%	-0.1	-1.1
Change in emissions	%	-0.5	-4.0
Consumption cost:[f]			
total amount	NZ$m	0.1	0.4
per tonne of demand-side abatement[g]	NZ$/t CO_2	1.6	1.6

a Transitional cap of $12.50/t CO_2 multiplied by emissions from electricity generation (around 6 Mt CO_2). **b** Electricity production in 2009 (IEA 2010f). **c** Average price reported by IEA (2010g) for residential customers in 2009 (NZ$243/MWh) and industry in second and third quarters of 2009 (NZ$111/MWh). The highest price is used to generate the 'low estimate' results (and vice versa) because it minimises (maximises) the proportionate price change from a given amount of carbon-price revenues and subsidy equivalents. **d** 2009 emissions reported by NZME (2011d) for public electricity and heat production. **e** Emissions intensity of the marginal generator used by Bartleet et al. (2010). **f** Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. **g** This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: Bartleet et al. (2010); IEA (2010f, 2010g); NZME (2011c); Productivity Commission estimates.

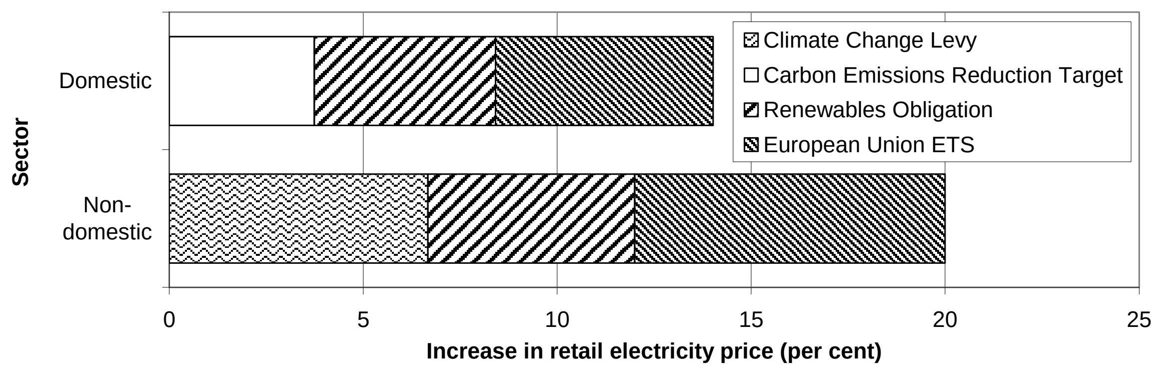
L.6 South Korea

All of the (six) South Korean policies included in the analysis of supply-side abatement are funded by taxpayers (appendix I). Hence, the Commission did not estimate demand-side abatement or consumption costs associated with those policies.

L.7 United Kingdom

The UK Government has estimated that, in 2010, its climate change and energy policies increased electricity prices by 14 per cent for domestic consumers, and 20 per cent for non-domestic consumers (DECC (UK) 2010d). Virtually all of the price impacts were attributed to just four policies — the Climate Change Levy, Carbon Emissions Reduction Target, Renewables Obligation, and European Union ETS (figure L.1).

Figure L.1 **UK Government estimates of abatement policy impacts on electricity prices, 2010**



Source: DECC (UK) (2010d).

Given the above predicted price impacts, the Commission estimates that the policies have reduced UK electricity consumption by between 3–12 per cent, and emissions by 3–19 per cent (table L.6).

Table L.6 **Estimated demand-side impacts of UK emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Production[a]	TWh	372	372
Retail price[b]	£/MWh	102	102
Emissions[c]	Mt CO_2	151	151
Emissions intensity of displaced output[d]	t CO_2/MWh	0.3939	0.6900
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price[e]	%	17	17
Change in electricity consumption	%	-3	-12
Change in emissions	%	-3	-19
Consumption cost:[f]			
total amount	£m	99	382
per tonne of demand-side abatement[g]	£/t CO_2	19	11

[a] Electricity production in 2009 (DECC (UK) 2010a). [b] Weighted average of 2010 retail prices for domestic (£122/MWh) and non-domestic (£90/MWh) consumers (DECC (UK) 2010d), with weights based on their shares of final electricity demand (38 and 62 per cent respectively in 2009, according to DECC (UK) 2010a). [c] 2009 data from DECC (UK) (2009). [d] Emissions intensities are the lowest and highest estimates used previously in this report's analysis of supply-side abatement. [e] Based on DECC (UK) (2010d) estimate that emissions-reduction policies caused retail prices to rise by £15/MWh in 2010 for both domestic and non-domestic customers. [f] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [g] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: DECC (UK) (2009, 2010a, 2010d); Productivity Commission estimates.

L.8 United States

Most of the US policies covered in the analysis of supply-side abatement are taxpayer funded, and so are not expected to lead to demand-side abatement (appendix K).[15] The remaining policies analysed here are the Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standards (RPS). The combined carbon-price revenues and subsidy equivalents for these policies was estimated to be between US$742 million and US$946 million. The calculations used to derive this range are outlined below.

[15] Policies excluded from the demand-side calculations are the Californian Emerging Renewable Program, Californian New Solar Homes Partnership, Californian Solar Initiative, Renewable Electricity Production Tax Credits, Self Generation Incentive Program, and Treasury Grants.

Regional Greenhouse Gas Initiative

The Commission concluded that the RGGI induces no supply-side abatement because the price of emissions permits (termed ‘allowances’) has been too low to induce fuel switching (appendix K). However, the cost borne by generators in purchasing permits could raise electricity prices, and thus induce some demand-side abatement.

New RGGI permits are sold in quarterly auctions, and existing ones can be purchased in a secondary market. The vast majority of permits have been purchased by generators at an auction. For example, in 2010, around 140 million permits were auctioned for the current control period (emissions occurring in the period 2009–2011) (RGGI Inc. 2011a). In contrast, only about 4 million such permits were exchanged in the secondary market in 2010 (Potomac Economics 2011). The Commission has therefore used auction prices to estimate demand-side abatement.

To date, there have been eleven quarterly auctions for RGGI permits (held from September 2008 to March 2011). The average permit price received at individual auctions has ranged from US$1.86 (September and December 2010 auctions) to US$3.51 (March 2009).[16] One of these permits has to be surrendered for each US (short) ton of CO_2 emitted during the period 2009–2011. On this basis, and given that 1 US ton equals 0.907184 metric tonnes, the price range for auctioned permits can be re-expressed as US$2.05–3.87/tonne CO_2. This price range was multiplied by 2009 electricity-sector emissions in the relevant states to derive a range for the annual cost to generators of the RGGI scheme.

In 2009, electricity generators in the ten RGGI states emitted 123.7 million US (short) tons (NYSERDA 2010b), which equated to around 112 Mt CO_2. This was well below the annual cap set by RGGI of 188 million US (short) tons (RGGI Inc. 2011b), or around 171 Mt CO_2. The Commission used actual emissions (112 Mt CO_2) in its demand-side calculations for the RGGI scheme. On this basis, the cost of the RGGI scheme to generators was estimated to be between US$230–434 million.

Renewable Portfolio Standards

As noted in the analysis of supply-side abatement, it was not possible to use the price of renewable energy certificates (RECs) to estimate the cost of each state’s RPS. The necessary price data were often unavailable, and there appears to be

[16] Excludes permits for post-2011 emissions.

limited trading of RECs because RPS requirements are often met through direct ownership of renewable capacity or bilateral contracts with renewable generators.

The supply-side analysis instead estimated the share of renewable generation induced by the RPS, and calculated an associated cost based on available financial information. This resulted in an estimated subsidy equivalent of US$512 million for the nine states analysed.[17] This amount is also used here for the demand-side calculations, on the assumption that the RPS only increases retail electricity prices to the extent that it induces additional generation of renewables. That is, no additional cost was attached to renewables generation that would have occurred without the RPS.

Data for other inputs to the calculations, such as electricity production and prices, were sourced from the IEA and US government agencies, as detailed in table L.7 below. The resulting estimates suggest that the analysed policies have a negligible impact on US electricity prices and hence result in little demand-side abatement in percentage terms.

[17] California, Colorado, Connecticut, Illinois, Massachusetts, Minnesota, Montana, New Mexico and New York. Among the remaining 41 states, 14 do not have an RPS, 7 have an RPS that sets an aspirational target with no compulsion for generators to achieve the target, 3 have an RPS that sets a relatively low target compared to pre-existing renewable generation, and 7 have an RPS that commenced after 2010.

Table L.7 **Estimated demand-side impacts of US emissions-reduction policies**

	Units	*Low estimate*	*High estimate*
Inputs to calculations			
Carbon-price revenues and subsidy equivalents	US$m	742	946
Regional Greenhouse Gas Initiative	US$m	230	434
Renewable Portfolio Standards	US$m	512	512
Production[a]	TWh	3 953	3 953
Retail price[b]	US$/MWh	116	68
Emissions[c]			
All states	Mt CO_2	2 270	2 270
RGGI states	Mt CO_2	112	112
Emissions intensity of displaced output[d]	t CO_2/MWh	0.406	0.908
Demand elasticity		-0.2	-0.7
Estimation results			
Change in retail electricity price	%	0.2	0.4
Change in electricity consumption	%	-0.03	-0.2
Change in emissions	%	-0.02	-0.4
Consumption cost:[e]			
total amount	US$m	0.1	1.2
per tonne of demand-side abatement[f]	US$/t CO_2	0.2	0.1

[a] Electricity production in 2009 (EIA 2011k). [b] Average 2009 price reported by IEA (2010g) for residential customers (US$116/MWh) and industry (US$68/MWh). The highest price is used to generate the 'low estimate' results (and vice-versa) because it minimises (maximises) the proportionate price change from a given amount of carbon-price revenues and subsidy equivalents. [c] 2009 emissions. National data from EIA (2011h). Data for RGGI states (California, Colorado, Connecticut, Illinois, Massachusetts, Minnesota, Montana, New Mexico and New York) from NYSERDA (2010b). [d] Emissions intensities are the lowest (0.406 t CO_2/MWh for California gas) and highest (0.908 t CO_2/MWh for mid-west coal and gas) estimates used in this report's analysis of supply-side abatement. [e] Consumers' valuation of forgone electricity consumption, less the valuation of other goods that can be purchased with the diverted expenditure. [f] This amount is typically greater for the 'low estimate' because the consumption cost is spread across a smaller reduction in emissions.

Sources: EIA (2011h, 2011k); IEA (2010g); NYSERDA (2010b); Productivity Commission estimates.