Potential Impacts of Subprime Carbon on Australia's Impending Carbon Market

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Abstract:

This paper examines the potential impacts of subprime carbon credits on the impending Australian carbon market. Subprime carbon could potentially be created in carbon offset markets that lack adequate regulation, as projects face risks that can overstate emissions abatement. Recent research suggests that subprime carbon credits will likely cause significant price instability in carbon markets, with some authors drawing parallels to the US market for mortgage backed securities during the subprime mortgage crisis (Chan, 2009). To assess the impacts of subprime carbon credits on the impending Australian carbon market, carbon price fundamentals are examined using a marginal abatement cost curve for the year 2020. The 2020 Australian marginal abatement cost curve is derived using a bottom-up model of the Australian electricity sector, as well as findings by the (DCC, 2009) and (McKinsey, 2008). Impacts are evaluated under several scenarios, which consider different trading scheme limits on the use of offsets; different proportions of offset credits that are subprime; and different emissions reduction targets. The results suggest that subprime carbon credits will always result in overall emissions reductions to be overstated, while sometimes increasing price volatility in the carbon market, depending on the steepness of the marginal abatement cost curve, the proportion of offset credits that are subprime, and the trading schemes limits on the use of offsets. We conclude that carbon markets could benefit significantly from a carbon offsets regulator, which would ensure the environmental and financial integrity of offset credits.

Keywords: Carbon Offsets, Marginal Abatement Cost, Carbon Market Regulation, Subprime Carbon
JEL Classification: Q52, Q31, L51, G18, G01

1. Introduction

The treatment of carbon offset projects in emissions trading schemes is one of the most controversial aspects of climate change policy, and since the Kyoto Protocol's Clean Development Mechanism (CDM) and Joint Implementation (JI), has become even more important. Controversy arises because carbon offset projects face the risk of overstating emissions abatement, and hence problems in generating legitimate carbon credits; a problem that allocated permits do not face. The risks most commonly cited concern the estimation of a projects baseline scenario; assessing additionally or carbon leakage; and the incentive incompatible nature of projects, and are discussed in more detail in section 2.

Concerns over the robustness of regulation in carbon offset markets have led to concerns that carbon offset markets may be under-regulated, with risks not been properly managed. One possible outcome of under-regulation, as discussed in (Chan, 2009, Bumpus, 2008, Rajan, 2009, Lohmann, 2009), is the creation of subprime carbon credits. Subprime carbon credits represent credits generated by an offset project that has overstated abatement. Because of this, they are essentially 'fake' and do not represent true emissions reductions. These credits would counteract efforts to reduce emissions, as credits are used elsewhere to offset emissions. They also have the potential to create price instability in carbon markets, with some authors drawing parallels to the US market for mortgage backed securities during the subprime mortgage crisis. Furthermore, under-regulation of offset projects could create a 'market for lemons', as described by (Akerlof, 1970), in which a large proportion of offset credits are subprime.

This study aims to measure the impacts of subprime carbon credits on a 2020 Australian Marginal Abatement Cost (MAC) curve. In constructing the MAC curve, an electricity sector model is used to derive abatement opportunities and relevant marginal abatement costs in the electricity sector. With energy usage accounting for almost two thirds of global carbon emissions (Stern, 2006), the general expectation is that the sector will be responsible for a significant proportion of reductions in future emission. The possible shifts in the availability of abatement opportunities due to under regulation of CDM's and JI credits could have significant effects on investment trends in the energy sector. The Electricity Supply Industry (ESI) will be expected to make significant efficiency gains over the next decade to improve its emissions performance (Menezes et al., 2009, Ross Lambie, 2010). With this general expectation of carbon emissions reduction this paper will examine the potential shift in the MAC and the consequences for carbon abatement opportunities in Australia. Studies by the Department of Climate Change (DCC, 2009) and McKinsey & Co (McKinsey, 2008) are used as a guide to calculate abatement opportunities and marginal abatement costs in other sectors. This paper proceeds with an overview of the regulation of these markets in section 2. In section 3 we will outline the methodological overview and in section 4 we move on to describe the construction of the MAC curve model. We construct the electricity sector model in section 5. In section 6 we use the results from the electricity sector model as input into our MAC curve model from which we derive our main findings. In section 7 we provide our analysis and recommendations and then provide some concluding remarks in section 8.

2. Background

2.1 General problems with carbon offsets

Carbon offset projects face a number of risks that can overstate emissions abatement. This raises concern over the legitimacy of the carbon credits which are generated through carbon offset projects; a problem not faced by the permits allocated by a regulatory authority (De Sepibus, 2009, Lund, 2010, Schneider, 2007). Difficulties associated with establishing additionality and permanence, as well as difficulties in estimating the baseline emissions and carbon leakage are identified as the key problems with carbon offset projects (Paulsson, 2009). A typical example is the problem of establishing permanence in long term sequestration projects, where plantations are at risk of burning down or been cleared. As well as this, carbon offset projects are largely regarded as incentive incompatible, with the usual business safeguards promoting fulfilment of contract been weak (Repetto, 2001).

Several researchers, such as (Bumpus, 2008, Chan, 2009, Lohmann, 2009), argue that these problems, combined with a lack of verification or regulation, is likely to create an offsets market lacking environmental and financial integrity. Several researchers have also expressed concern over the integrity of offset credits in the Kyoto Protocol, which are regulated by the CDM and JI executive boards (Haya, 2007, Schneider, 2007).

Problems with verifiability could also lead to carbon offsets markets developing into a market for ‘lemons’ (Akerlof, 1970, Obersteiner et al., 2000). Because buyers of offset credits are unable to determine whether the offset project has generated additional emissions reductions, companies selling offsets will have an incentive to sell non-additional offsets, because they are cheaper to deliver, and pass them off as additional. It is generally acknowledged throughout the literature (for example, see (Downie and Institute, 2007) or (Repetto, 2001)), that in the absence of rigorous offset standards, carbon credits could be generated by projects where it is difficult to guarantee the creation of additional reductions in greenhouse emissions, from what would have occurred under a BAU scenario.

Additionality

Additionality is the requirement that emissions after an offset project are less than those that would have occurred otherwise (Drew and Drew, 2010). Establishing whether a project is additional is difficult offset projects often have parameters which are hard to observe or are subject to change (Chan, 2009, Chomitz, 1999, Grubb et al., 2010, Michaelowa and Jotzo, 2005, Repetto, 2001, Schneider, 2007, Schneider, 2009). As well as this, the incentive for parties to deliberately misrepresent or manipulate parameters of the project further complicates the assessment of additionality (Chomitz, 1999, Repetto, 2001).

The CDM and JI executive boards have come under scrutiny for being too lenient in their approval of carbon offset projects. Recent research, which assesses the additionality of CDM projects, found many are not likely to be completely additional (Haya, 2007, Michaelowa and Purohit, 2007, Schneider, 2007, Wara and Victor, 2008). For example, (Michaelowa and Purohit, 2007) analysed 52 approved CDM projects in India and found at least two approved projects that were not additional and 19 projects that should have been rejected by the CDM executive board.

(Wara and Victor, 2008) examined applications for CDM credits resulting from renewable energy projects in China. They found that almost all new renewable energy and gas plants under construction in China applied for CDM credits. They argue that if these projects were additional, it would imply that no new hydro, wind or gas power plants would be developed; and point out that this would be unlikely given China’s five-year plan calling for major investments in hydro, wind, nuclear and natural gas-fired power.

(Haya, 2007) found that of all hydro projects approved by the CDM executive board, more than one third were already completed at the time of the projects registration, and almost all were already under construction. This indicates that the hydro projects would have likely gone ahead without the CDM credits, suggesting they were mostly not additional.

Such difficulties in assessing additionality, especially under a poorly regulated system with little oversight, is likely to result in some projects, which are not fully additional, obtaining credits for emissions reductions. Such non-additional credits, which are essentially worthless or subprime, will result in an increase in total emissions, as credits will be used to offset greenhouse gases elsewhere.

Baseline estimation

The emissions reductions resulting from offset projects depends on an unobservable BAU scenario, the measurement of which, is regarded as a key risk in quantifying emissions reductions. Projects often have long time frames, which need to be compared to a long term BAU scenario which is difficult to measure, as it depends on a variety of economic, political and technological trends that change over time (Chomitz, 1999, Grubb et al., 2010, Michaelowa, 1998, Repetto, 2001, Millard-Ball and Ortolano, 2010).

As well as this, offset markets without a standardised methodology for the computation of BAU scenarios will likely result in the use of different methods among parties (Michaelowa, 1998). This may result in parties attempting to calculate BAU scenarios in such a way that overstates a projects abatement.

Carbon leakage

Difficulties assessing carbon leakage also create problems for assessing emissions reductions. Carbon leakage arises when emissions reductions at one location result in increased emissions elsewhere. (Chomitz, 1999) uses the example of a project that reduces demand for fuels, resulting in slightly depressed prices, to which consumers react by slightly increasing consumption.

(Repetto, 2001) points out that leakage could also be driven by manipulation, in a similar manner to how corporations could shift profits among countries to reduce tax liabilities. He argues polluters could concentrate emissions reductions in countries in which they can generate CDM credits and locate an offsetting increase elsewhere (for example shutting down an energy intensive industrial process in one country while outsourcing the process to another country) (Repetto, 2001). By not taking into account carbon leakage, offset projects will overstate emissions reductions (Millard-Ball and Ortolano, 2010, Repetto, 2001).

Incentive incompatibility

Carbon offset projects are largely regarded as incentive incompatible, as parties involved in the project have incentives to 'cheat' (Michaelowa, 1998). (Repetto, 2001) argues that this is because the normal business safeguards promoting fulfilment of contracts are absent or weak, as neither parties are concerned whether the emissions reductions have taken place, only that the buyer receives the title to the credits and the seller receives the payment (Repetto, 2001) p.311. This could lead to situations where parties attempt to overstate the actual emission reductions or skimp on implementation (Chomitz, 1999, Michaelowa, 1998, Repetto, 2001).

Because of the incentive incompatible nature of projects, it further raises concerns over the legitimacy of project baselines and increases the difficulty in assessing additionality. It also raises concern over the extent to which these variables can be manipulated to overstate emissions abatement, and hence allow projects to earn additional credits.

2.2 Parallels to the global financial crisis

(Chan, 2009) argues there are a number of similarities between carbon markets and the US market for mortgage backed securities prior to the financial crisis, with some research drawing parallels with the recent financial crisis (Chan, 2009, Lohmann, 2009, Rajan, 2009). The most common similarities include the creation of increasingly complicated assets, a lack of transparency in the securitisation of asset backed securities, the potential miscalculation of risk by credit rating agencies, and in some cases lenient government regulation (Ayadi and Behr, 2009, Caprio Jr et al., 2010, Chan, 2009, Hull, 2009, Mason and Rosner, 2007, Tymoigne, 2009). (Chan, 2009), (Ayadi and Behr, 2009) and (Lohmann, 2009) point out that carbon-backed securities are turned into increasingly complicated products which face similar asset valuation challenges to mortgage-backed securities prior the financial crisis. (Szabo, 2008) points out that similar types of asset structures already exist in carbon markets; citing a Credit Suisse announcement to securitize a carbon asset which bundled together carbon credits (from 25 offset projects at various stages of UN approval, sourced from three countries, and five project developers) in late 2008, which was split into three tranches (representing different risk levels) and sold to investors.

(Chan, 2009, Hull, 2009, White, 2009, Mason and Rosner, 2007), also point out the problems associated with credit rating agencies assess risk in carbon markets. They argue the failure of credit rating agencies to accurately assess the risk of mortgage backed securities and collateralised debt obligations prior to the financial crisis, could also occur in carbon markets, with some researchers arguing it could be as difficult, if not more so, to analyse the quality of the numerous underlying carbon offset projects, as it is to analyse US mortgages (for example see (Chan, 2009)).

3. Methodology

3.1 Methodology overview

To measure the impacts of subprime carbon, a marginal abatement cost model is used[1]. The abatement opportunities for the MAC model are obtained through a bottom up model of the Australian electricity sector (outlined in section 4) as well as the results from (McKinsey, 2008) and the (DCC, 2009).

A MAC curve shows the set of optimal abatement opportunities available to reduce pollution, and is the basis for modelling carbon price fundamentals. The marginal abatement cost refers to the cost of eliminating an additional unit of emissions, and is assumed to be equal to the carbon price. A simple example is given in figure 1.

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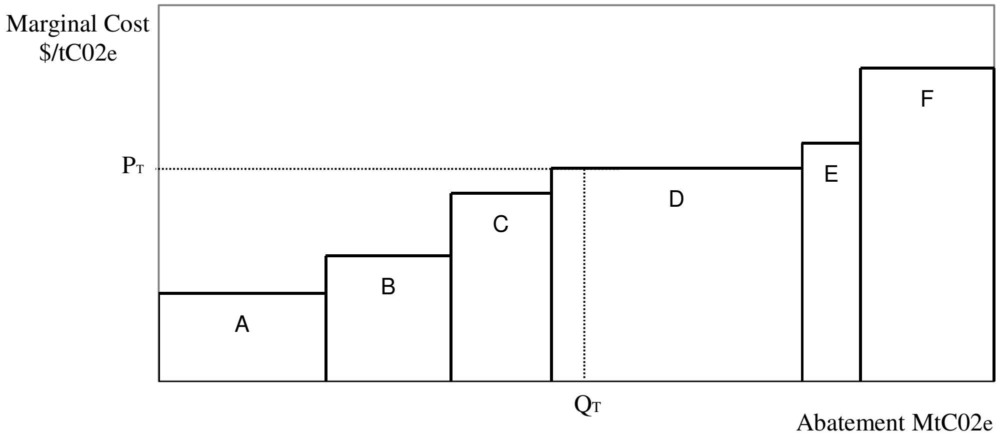
[1] All dollars throughout this analysis are 2009-10 Australian dollars unless otherwise stated.

Figure 1: A Typical MAC curve



The x-axis shows potential abatement opportunities while the y-axis shows the marginal abatement cost. The boxes labelled A to F represent the potential abatement opportunities. The demand side of the model is the emissions reduction target, and is assumed to be binding. The expected carbon price is the marginal abatement cost of the abatement opportunity required to meet the reduction target, shown by the dotted lines. Q_T represents the emission reduction target and the corresponding marginal cost, P_T, is the carbon price.

In this study, the MAC model is will assign a carbon price under different reduction targets (5 per cent, 15 per cent and 25 per cent reduction compared to 2000 levels, assuming all the policy and trends in place as at 2009) and different trading scheme limits on the use of offsets (we assume offsets are limited as a proportion of total abatement, at 10 per cent, 20 per cent, 30 per cent, 40 per cent and 50 per cent). The impacts of subprime carbon are then analysed by decreasing the size of the offsets abatement width on the MAC curve, to reflect the proportion of subprime carbon (we run several scenarios to take into account different proportions of subprime credits, these are 10 per cent, 20 per cent, 30 per cent, 40 per cent and 50 per cent).

4. Australian Electricity Sector Model

4.1 Methodology overview

The Australian electricity sector model is used to identify potential abatement opportunities in the National Electricity Market (NEM) for the purpose of constructing the 2020 Australian MAC curve. The NEM is modelled using an optimal plant mix model outlined in (Simshauser and Wild, 2009) and (Wagner, 2011). The model uses a load duration curve[2] and annual equivalent cost curves[3] to determine the optimal generation mix[4] for the NEM using a partial equilibrium model constructed using a linear programme[5]. Emission permit prices are added to the model to evaluate the optimal plant mix at each carbon price, and using an iterative procedure, allowing for optimal abatement opportunities to be derived.

Only combustion technologies are modelled this way. Renewable energy is assumed to contribute 10 per cent, or 22,500MWh to capacity (and hence a fixed abatement) with the most cost effective mix of renewable technology determined by optimal plant mix model[6].

A typical construction is shown for a single year in figure 2, with the straight lines illustrating the above equation for increments of open cycle gas turbine (OCGT) plant, Combined Cycle

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[2] A load duration curve is a representation of hourly electricity load, typically for a given year, with the data ranked in descending order. Each percentage of the annual capacity factor corresponds to a point on the load duration curve (in MWs).

[3] The annual equivalent cost curves represent the total cost for any year of installing and operating an increment of generating plant capacity, discussed in section 4.2. A curve exists for each technology and is projected over the annual capacity factor

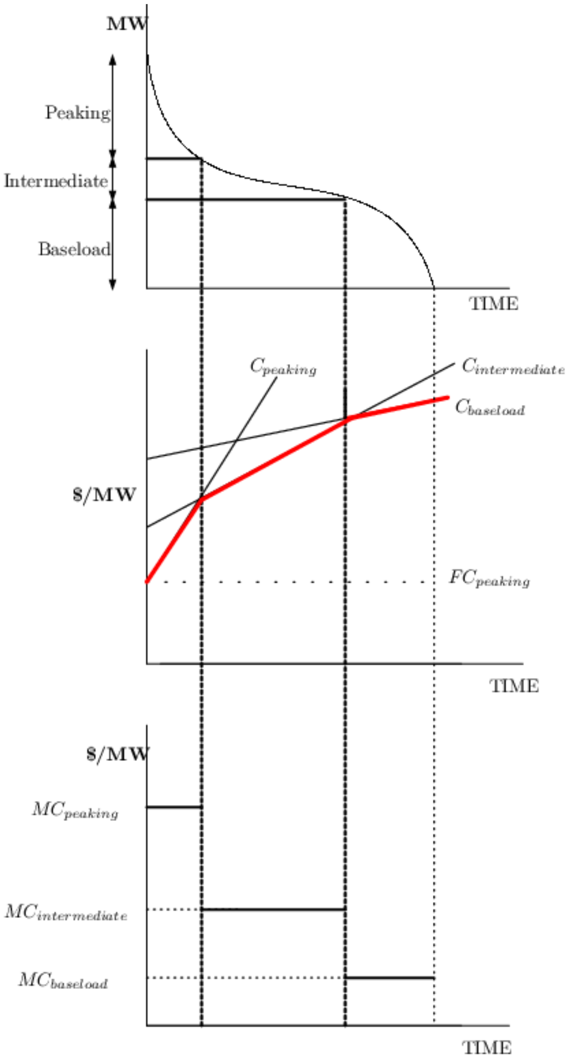
[4] The optimal plant mix refers to the cost minimising mix.

[5] Once the cost paths are computed, cross over points are determined which shows the optimal plant mix.

[6] The 20 per cent renewable energy target is assumed to be part of the baseline. Given the intermittent nature of renewable power generation, it is assumed the maximum contribution of renewable energy is 30 per cent in 2020.

Gas Turbine (CCGT) plant and coal fired generation plant. In the direction of increasing annual capacity factor, OCGT is seen to give the lowest total cost until its cost line intersects that of the CCGT plant; which provides the lowest total costs until the coal fired generation line is encountered. This is the interior solution to figure 2. In order to calculate the appropriate MW of capacity each plant type contributes, the intersection points are referred to the load duration curve as shown by the dotted lines in figure 2.

Figure 2: Example of a Berrie Static Partial Equilibrium for a load curve



Additional assumptions

Renewable Energy Certificates (RECs) are assumed to be \$40/MWh. Inclusion of a \$40/MWh REC price is consistent with artificial price floor imposed on the REC market (CSIRO, 2010). Gas Electricity Certificates (GECs) are not included in this analysis, as it is uncertain that the scheme will continue beyond 2015.

All generation technologies under consideration in this analysis are assumed to be perfectly available in 2020. The generation technologies included in the model are shown on table 3. Carbon capture and storage, hydro-electricity and nuclear power are not expected to be available for deployment in 2020.

4.2 Definition of Variables

Discount rate

For the purpose of this analysis, a post-tax real weighted average cost of capital (WACC) is used. A post-tax WACC is used because of the importance of depreciation for capital intensive plant such as power stations (ACIL Tasman, 2009).

The post-tax nominal WACC is expressed as:

$$WACC_{post-tax\ nominal} = \frac{E}{V} \times R_e \left(\frac{(1 - T_E)}{(1 - T_E(1 - G))} \right) + \frac{D}{V} \times R_d (1 - T_E) \qquad (1)$$

Where

- E is the total market value of equity

- D is the total market value of debt
- V is the total enterprise value (value of debt plus equity)
- R_e is the nominal post-tax cost of equity
- R_d is the nominal post-tax cost of debt
- T_E is the effective corporate tax rate
- G (gamma), which is the value of imputation tax credits as a proportion of the tax credits paid.

The nominal post-tax WACC is adjusted into real terms using the Fischer equation as follows:

$$WACC_{post-tax\,real} = \left(\frac{(1 + WACC_{post-tax\,nominal})}{(1+F)}\right) - 1, \tag{2}$$

Where F is the inflation rate

Inflation

Long run inflation is assumed to prevail at the midpoint of the Reserve Banks official target range, at 2.5 per cent. The basis upon which inflation is applied to all subsequent modelling is at full CPI against operating cost streams, and only three quarters CPI against revenue streams. The pass through of inflation (ρ), throughout this modelling will be considered to be ρ_R=75% for revenue streams and ρ_C=100% for non-finance related operating costs.

$$CPI(t)_R = \left\{\left[1 + \left(\frac{3}{100}\right)\right] * \rho_R\right\}^t \tag{3}$$

$$CPI(t)_C = \left\{\left[1 + \left(\frac{3}{100}\right)\right] * \rho_C\right\}^t$$

Operations and maintenance (O&M) costs escalation will be at the rate of $CPI(t)_C = 3\%$ in accordance with the aforementioned cost stream pass through rate (Simshauser and Wild, 2009). Variable t is defined to represent a discrete time index starting in the first period of the projection horizon and containing N time periods (i.e. $t = 1, \ldots, N$) with parameter N corresponding to the useful life of the plant (given on table 3).

Short-Run Marginal Cost

The SRMC is used to calculate the annual equivalent cost and is defined as a period of time where at least one input variable remains fixed. In the case of power generation, the short-run is usually defined as being a period where generation capacity remains fixed. Therefore, the SRMC is the incremental cost incurred from an increment of output (i.e. 1 MWh) from a generation technology.

For the purpose of this analysis, the short-run is defined as a period of one year. Therefore the SRMC can be defined as being the additional cost incurred from producing an additional MWh on average over the course of the year. The SRMC is used in calculating the AEC ($/kW/year) for each technology type. The cost of carbon affects the cost of power generation by contributing to the SRMC.

All of the relevant inputs that form the SRMC are:

- The average marginal thermal efficiency for a station over the year
- The average fuel cost incurred over the year
- The average marginal variable O&M costs incurred over the year
- The average marginal emission factors and permit price over the year

The estimated SRMC for each power station is calculated using the following formula;

$$SRMC = \left(HR \times FC + VOM + TE \times \left(\frac{EIF}{1000}\right) \times EPP\right) - REC \tag{4}$$

Where:

- SRMC is the short-run marginal cost on a sent-out basis (in \$/MWh)
- HR is the heat rate on a sent-out basis (in GJ/MWh)
- FC is the fuel cost (in \$/GJ)
- VOM is the variable operating and maintenance cost on a sent-out basis (in \$/MWh)
- EIF is the emissions intensity factor (in kg CO_2e/GJ)
- EPP is the emissions permit price (in \$/tCO_2e/MWh)
- REC is any benefit derived from the production of certificates under the Renewable Energy Certificates Scheme (in \$/MWh)

Long-Run Marginal Cost and the Levelised Cost of Energy

The long-run is usually defined as a period of time in which all inputs can be varied. In the case of the generation sector the key difference in inputs that can be varied is the capacity of the generation fleet. In terms of generation technologies, the long-run marginal cost (LRMC) is typically referred to as the levelised cost of energy (LCE) which represents the long run cost of the technology amortized over the estimated economic life. This allows the comparison of plant costs that have different economic lives. Therefore, the levelised cost is defined as the cost of an incremental unit of generation capacity, spread across each unit of electricity produced over the life of the plant.

The LCE for each plant is estimated based on a discounted cash flow (DCF) model. In broad terms calculating the levelised cost of a new entrant plant involves calculating the present value of the time profile of annualised plant costs deflated by the time profile of revenue accruing to the plant over its lifespan. This is then adjusted by the amount of power that is expected to be consumed internally, referred to as auxiliary load and represented by an expense weighting factor 'Aux'. The present value of total costs and total revenue are given by;

$$TCPV = PV\big(TC(t)\big) \tag{5}$$

$$TRPV = PV(RS(t)) \tag{6}$$

Where;

- TCPV is the present value of total costs
- TRPV is the present value of total revenue

It is assumed that the revenue stream is proportional to the output of each plant. The revenue stream for each generator is calculated by applying the assumed revenue inflation escalation rate to the output generated by each respective generator. This is given by;

$$RS(t) = ES(t) \times CPI(t)_R \tag{7}$$

Where;

- $RS(t)$ is the revenue stream of each generating plant j
- $ES(t)$ is the energy generated by plant

The costs considered include all costs relevant to the investment decision. These costs are:

- The capital cost (including connection and other infrastructure)

- Other costs including legal and project management costs
- Fixed operating and maintenance costs
- Variable costs over the life of the station (including the cost of emissions)
- Tax costs

Total costs include the sum of fixed and variable costs. The fact that variable cost streams depend on the output of the plant has been taken into account by applying the cost inflation escalation rate to the output generated by each respective generator. This is given by;

$$TC(t) = VC \times ES(t) \times CPI(t)_C + Fixed\ Costs \tag{8}$$

Where;

- $TC(t)$ is the total costs by generator
- VC is the variable costs
- $ES(t)$ is the energy generated by plant in MWh
- $CPI(t)_c$ is the 'inflation escalation rate' applied to generator costs

Finally, the LCE is calculated as;

$$LCE = TCPV \ / \ TRPV \ /(1 - Aux) \tag{9}$$

Where;

- LCE is levelised cost of energy ($/MWh)
- Aux is the auxiliary load

Annual Equivalent Cost

The Annual Equivalent Cost (AEC) curves represent the total cost for any year of installing and operating an increment of generating plant capacity. It is the sum of its annual capital charges (discounted to present value) and the product of its operating over capacity it contributes to the annual capacity factor. The cost path for each plant are given by a linear function which represents the total annual cost for the increment of annual capacity factor $AEC = OC(ACF) + x,$ where x is the annual capital charges of the increment of capacity, OC is its operating cost per unit of time and ACF is the percent (from zero per cent to 100 per cent) of capacity it contributes to the annual capacity factor. Once annual equivalent cost curves are calculated, cross over points can be determined which provides the optimal plant mix under a specified carbon price.

In converting LCE (in \$/MWh) to AEC (in \$/kW/year) the following process is used;

$$AEC = (LCE - SRMC) \times \big(SRMC \times CF \times 8.76 \times (1 - Aux)\big) \qquad (10)$$

Where;

- $SRMC$ is the short-run marginal costs (fuel, variable O&M and emission costs) in \$/MWh
- 8.76 is the number of hours in a year divided by 1000
- CF represents the proportion of total system capacity from the generation technology[7]

Emissions and Emissions Reductions

Because emissions data is given in t/MWh it is necessary to convert the MW from the load duration curve into MWh. This is done using the following process;

$$MWh = MW \times 8760 \times CF \qquad (11)$$

Where;

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[7] A percentage between 0% and 100% such that the sum of all annual capacity factor equals 100% (i.e. such that $\sum_{j=1}^{n} ACF_j = 100\%$)

- MWh is megawatt hours
- MW is the nameplate capacity in megawatts
- 8760 is the number of hours in a year

Given this, emissions reductions from switching from technology a to technology b (or from changing from a baseline scenario *b* using technology *a*) are calculated as follows;

$$Abatement\ (Mt)_{b,a} = MWh_b \times \left(\frac{tC0_2e}{MWh}\right)_b - MWh_a \times \left(\frac{tC0_2e}{MWh}\right)_a \tag{12}$$

Where;

- $Abatement\ (MT)_{b,a}$ is the reduction in MT from switching from technology (or baseline) *b* to technology *a.*
- MWh_j is megawatt hours from technology $j = a, b$

Marginal Abatement Cost for Renewable Technologies

The marginal abatement cost for renewable technologies is the additional cost of switching to a renewable technology compared to the baseline divided by the amount of emissions reduction relative to the baseline. This can be written as;

$$MAC_R = \frac{LRMC_R - LRMC_B}{C0_2e_B - C0_2e_R} \tag{13}$$

Where;

- MAC_R is the marginal abatement cost (in \$/tonne of abatement)
- Subscripts *R* and *B* represent renewable and baseline technologies respectively

4.3 Model calibration

Model calibration and assumptions are shown in tables 1 to 3.

Table 1: LRMC of renewable technologies

Technology	LRMC ($/MWh)
Solar Tower	78.50
Geothermal	36.16
Solar Thermal	113.71
Solar PV	96.22
Wind	74.29
Biogas	52.64

Table 2: WACC Parameters

	Parameters	**Value**
$D+E$	Liabilities	100%
D	Debt	60%
E	Equity	40%
R_f	Risk free RoR[8]	6%
$MRP = R_m - R_f$	Market risk premium	6%
R_m	Market RoR	12%
T	Corporate Tax Rate	30%
T_e	Effective tax rate	22.5%
	Debt basis point premium	2%
R_d	Cost of debt	8%
G	Gamma	0.50
B_a	Asset beta	0.80
B_d	Debt beta	0.16
B_e	Equity beta	1.75
R_e	required return on equity	16.5%
F	Inflation	2.50%
post-tax real WACC		6.81%

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[8] Rate of Return

Table 3: Parameters for Calculating Costs and Emissions for 2020

	Capital cost ($/kW)	Unit size (MW)	Variable O&M ($/MWh)	Fixed O&M ($M pa)	Useful life (years)	Heat rate (MJ/MWh)	Fuel cost ($/GJ)	Auxiliaries (Sent Out % of Generated)	Emissions Intensity (t/MWh)	Capacity Factor (%)	Capex Rate (%)	Fixed ($/MWh)	Variable ($/MWh)	LCE ($/MWh)
Brown Coal	2297	500	1.25	27.5	40	11250	0.55	0.89	1.05	87	1.5	35.49	7.44	42.93
Black Coal	2036	500	1.25	20	40	8570	1.30	0.93	0.82	80	1.5	31.88	12.39	44.28
Geothermal	4719	500	2.05	35	30	5140	0	0.975	0	80	2.0	34.11	2.05	36.16
Biogas	2068	50	1.25	0.00025	20	9230	5.49	0.995	0	80	3.0	0.73	51.91	52.64
Wind Turbine	2908	0.01	0.001	0.000005	25	0	0	0.99	0	27	2.4	74.29	0	74.29
Solar PV	2408	0.04	0	0.000002	25	0	0	1	0	18	2.4	96.22	0	96.22
Solar Thermal	3420	200	0	10	25	0	0	0.99	0	27	2.4	113.71	0	113.71
Solar Tower	3622	200	0	9.132	30	0	0	1	0	35	2.0	78.50	0	78.50
OCGT	866	150	7.70	1.95	30	11500	5.50	0.99	0.66	80	2.0	19.46	70.95	90.41
CCGT	1208	400	1.05	12.4	30	6910	5.50	0.96	0.42	80	2.0	24.73	30.06	63.79

Note: real 2009-10 dollars
Sources: ACIL Tasman (2009), CSIRO (2009), iGrid (XXX)

Load Duration Curve Data

Data used to construct the load duration curve for combustion technologies[9], and to calculate the potential contribution of renewable for the year 2020 is derived from the AEMO State of Opportunities (2009).

The specific demand forecasts correspond to those associated with the 50 per cent 'probability of exceedance' standards which reflect demand forecasts that have been constructed using different assumptions about prevailing weather conditions and economic growth scenarios (AEMO, 2009). The baseline demand scenario is associated with a standard or median weather forecast and a median level of economic growth and energy consumption.

Baseline Data

Baseline data is derived from CSIRO (2009). Baseline Emissions Intensity for the year 2020 is expected to be approximately 0.94t/MWh. The average spot price in 2020 is expected to be $26.46/MWh (CSIRO, 2009). For the purpose of this analysis, this spot price is used as the baseline LRMC.

4.4 Model results

The key emission permit prices that change the interior solution for combustion technologies are summarised in table 4.

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[9] Load duration curve minus the contribution of renewables.

For combustion technologies, model results show that from around seven per cent to 100 per cent of the annual capacity factor, the interior solution switches from coal based generation technologies to gas based generation technologies. For renewable technologies, zero per cent to 30 per cent of the interior solution consists of Biogas, while the remaining contribution consists of wind.

Table 4: Model results

Carbon Price ($)	Technology	Annual Capacity Factor (%)	Corresponding MW	GWh	Emissions Reduction (MT)
Combustion					
37.50	Coal to CCGT switching	12 - 100	27 000	189.20	98.40
Renewable					
27.20	Biogas	0 – 30	2 568	6.75	6.35
51.21	Wind	30 - 100	5 993	15.75	14.80

5. MAC Model

5.1 Model calibration

The three emissions reduction targets (demand scenarios) are 5 per cent (138MT), 15 per cent (194MT) and 25 per cent (249MT) below 2000 levels by 2020 (DCC, 2009). The emissions trajectory out to 2020, without an emissions trading scheme, and including the 20 per cent renewable energy target, is assumed to be 664MT (DCC report).

Only the sectors contributing the bulk of emissions are examined. Electricity sector abatement is from the electricity sector model. Forestry and agricultural sector is from McKinsey (2008) and DCC (2009).

It is assumed that significant abatement potential is available through carbon offset projects, whether they are domestic or via the CDM and JI[10], at \$28/tCO_2e, which is in line with recent forecasts (Chestney, 2011).

Abatement opportunities are shown on tables 5 and 6.

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[10] In 2007, the CDM and JI accounted for almost 600Mt of pollution reduction under the EU ETS CAPOOR, K. & AMBROSI, P. 2009. State and trends of the carbon market 2009. *Washington DC: The World Bank.*. Further to this, global cost curve modeling by MCKINSEY 2008. An Australian Cost Curve for Greenhouse Gas Reduction. MCKINSEY & CO INC. indicates that significant abatement potential exists in developing countries below \$40 per t/CO_2e

Table 5: Abatement opportunities

Abatement Opportunity	Volume ($MTCO_2e$)	Marginal Abatement Cost ($\$/MTCO_2e$)
Agriculture, livestock	5	10
Afforestation, pasture	20	25
Forest management	10	27
Biogas	6.35	27.20
Carbon offsets	See table 6	28
Coal to gas	98.40	37.50
Refforestation	15	40
Soil CO2	5	47
Avoided deforestation	45	50
Wind	14.81	51.2
Afforestation, crop land	15	52
Agriculture, waste	5	56

Sources: DCC (2009), McKinsey (2008) and Energy sector model

Table 6: Offset opportunities

Target	Volume Available ($MTCO_2e$)	Price ($/$MTCO_2e$)
10% offsets		
5%	27.6	28
15%	38.8	28
25%	49.8	28
20% offsets		
5%	69.0	28
15%	97.0	28
25%	124.5	28
30% offsets		
5%	69.0	28
15%	97.0	28
25%	124.5	28
40% offsets		
5%	69.0	28
15%	97.0	28
25%	124.5	28
50% offsets		
5%	69.0	28
15%	97.0	28
25%	124.5	28

5.2 Results

The prevailing carbon price under each scenario is summarised in table 7. The carbon price is consistently lower under scenarios with a higher proportion of available offsets, suggesting that the MAC curve is sensitive to the limits imposed on the use of offset credits.

Because of the large number of scenarios, only the 15 per cent reduction target, with 30 per cent available offsets is shown diagrammatically (see figure 3). The others are summarised in table 7.

Figure 3: marginal abatement cost curve and corresponding carbon price under a 15 per cent reduction target and a 30 per cent limit on offsets

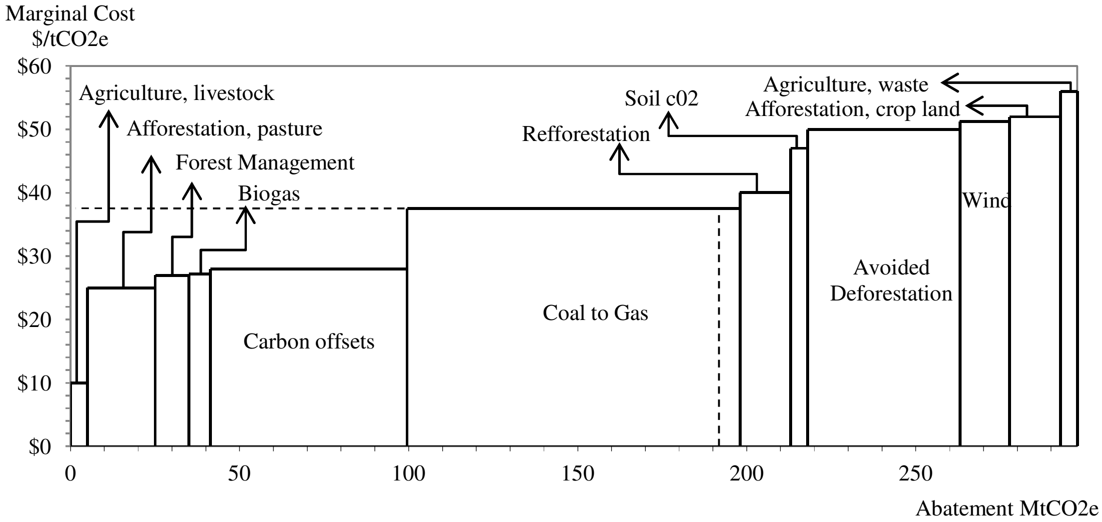


Table 7: Summary Table

Target (%)	Prevailing Carbon Price ($)
10% offsets	
5	37.5
15	50
25	52
20% offsets	
5	37.5
15	47
25	50
30% offsets	
5	37.5
15	37.5
25	50
40% offsets	
5	37.5
15	37.5
25	40
50% offsets	
5	37.5
15	37.5
25	37.5

Table 8: Summary of Results

% subprime	5% target		10% target		25% target	
	Impact on Abatement	Impact on Price	Impact on Abatement	Impact on Price	Impact on Abatement	Impact on Price
10% limit on offsets						
10%	1.38	0	1.94	0	2.49	0
20%	2.76	0	3.88	0	4.98	0
30%	4.14	0	5.82	0	7.47	0
40%	5.52	0	7.76	0	9.96	0
50%	6.9	0	9.7	0	12.45	4
20% limit on offsets						
10%	2.76	0	3.88	0	4.98	0
20%	5.52	0	7.76	3	9.96	1.2
30%	8.28	0	11.64	3	14.94	1.2
40%	11.04	0	15.52	3	19.92	1.2
50%	13.8	0	19.4	3	24.9	2
30% limit on offsets						
10%	4.14	0	5.82	2.5	7.47	0
20%	8.28	0	11.64	2.5	14.94	0
30%	12.42	0	17.46	2.5	22.41	0
40%	16.56	0	23.28	9.5	29.88	0
50%	20.7	0	29.1	12.5	37.35	1.2
40% limit on offsets						

10%	5.52	0	7.76	0	9.96	7
20%	11.04	0	15.52	0	19.92	10
30%	16.56	0	23.28	0	29.88	10
40%	22.08	0	31.04	2.5	39.84	10
50%	27.6	0	38.8	9.5	49.8	10
50% limit on offsets						
10%	6.9	0	9.7	0	12.45	0
20%	13.8	0	19.4	0	24.9	2.5
30%	20.7	0	29.1	0	37.35	12.5
40%	27.6	0	38.8	0	49.8	12.5
50%	34.5	0	48.5	2.5	62.25	12.5

6. Analysis and Results

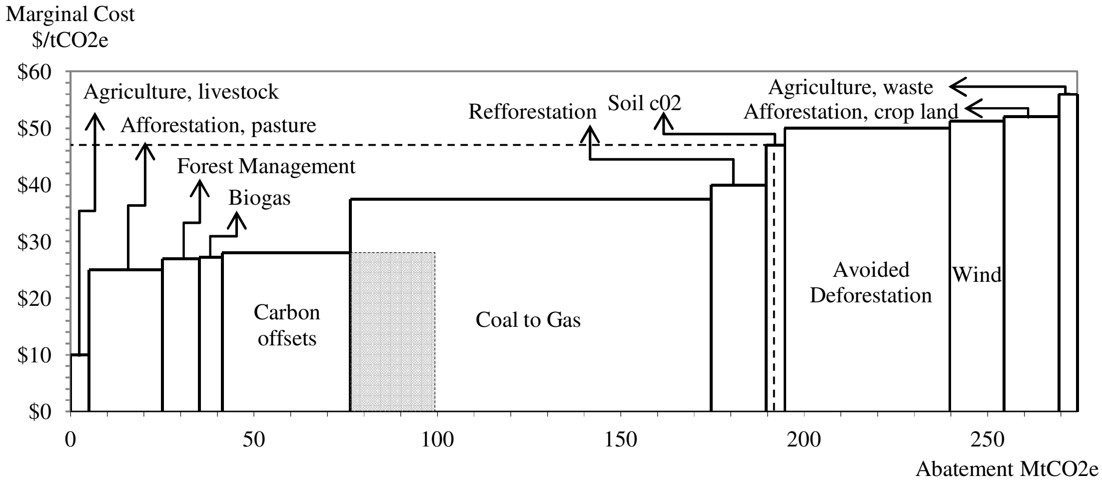
Results are shown in table 8. In all cases, subprime carbon causes initial abatement to be overstated, with the overstatement much higher in scenarios which have a greater proportion of offsets allowed, as well as scenarios which have greater proportions of subprime carbon. In the worst case, with 50 per cent allowable offsets and 50 per cent subprime carbon, abatement is overstated by as much as 62.25MT (and as little as 34.5MT) depending on the reduction target.

The price impact refers to both the short-term downward pressure caused by the increased supply of abatement opportunities, and also the longer term increase in price if information becomes available on which offsets are subprime (i.e. information asymmetries disappear). The affects on price caused by subprime carbon varies significantly between different scenarios. This result can be attributed to the relative flatness of the MAC curve over some of the abatement opportunities (such as coal to gas) and at higher abatement levels (on the far right side of the MAC curve). The flatness of the MAC curve in this area means that the price will remain stable given small to medium size changes in the reduction target, or changes to abatement opportunities preceding it. Price impacts are typically larger in scenarios which allow more offsets to be used, as well as in scenarios which have a great proportion of subprime carbon. In the worst case, with 50 per cent allowable offsets and 50 per cent subprime carbon, the price impact is as much as \$12.50 (and as little as \$0) depending on the reduction target. This is because the change in offset opportunities exposes the reduction targets to steeper sections of the MAC curve.

The results suggest that the impact of subprime carbon on both abatement and price are much larger when a less restrictive limit on the use of offsets is imposed, this is to be expected, given that subprime credits make up a larger proportion of the carbon market. Furthermore, the results suggest that the MAC curve is sensitive to the limits imposed on the use of offset credits.

Diagrammatically, the analysis is shown on figure 4.

Figure 4: Marginal abatement cost curve and corresponding carbon price under a 15 per cent reduction target, a 30 per cent limit on offsets and 40 per cent subprime carbon



6.1 Limitations of the MAC model

Price formation in a 2020 Australian carbon market will depend on more than just marginal abatement cost. Price determination involves a complex interplay between emissions reductions targets, marginal abatement costs, dynamic technology costs, market rules, government policy and many other factors (Blyth et al., 2009). Furthermore, emissions trading markets are typically international markets, so price formation depends on more than just domestic supply and demand.

6.2 Limitations of the ESM model

The electricity sector model used to compute the abatement opportunities in the electricity sector is a bottom-up model. Bottom–up models most often represent the energy sector in significant detail. The high level of technical detail is argued to be their main advantage (Delarue et al., 2009, Shukla, 1995). These models are based on cost information about existing and future technologies and attempt to identify cost minimising combinations of technologies using linear-programming (Springer, 2003).

One problem with using bottom-up models is the inability to take into account economy wide effects and feedback effects (Springer, 2003). Furthermore, many bottom–up models do not endogenise human behaviour (Springer, 2003), so consumer and producer reactions are determined by external assumptions rather than by the model. (Michaelowa and Jotzo, 2005) argue the second-order (or feedback) effects aren't captured by bottom-up models are likely to be small in comparison to the primary parameters that shape the permit market.

Another problem is that the electricity sector model includes many assumptions for parameters that are uncertain and in some cases evolving rapidly. Parameters of most concern are the future cost, performance and availability of different technology options. This is partially addressed by consulting a wide variety of parameter estimations.

Finally, the electricity sector model does not directly take into account technological change or learning. The parameters used in the model and developed by (ACIL TASMAN, 2009, CSIRO, 2009) do take into account technological change.

7. Conclusions

Under-regulation of project-based mechanisms in dealing with climate change risk creating subprime carbon and a potential market for lemons. Few studies, if any, have explored the effects of such under-regulation and the affects of subprime carbon. The primary aim of this study has been to examine the potential impacts of under-regulation and resulting subprime carbon on an impending Australian carbon market. This study has used a MAC curve derived from a bottom-up model of the Australian electricity sector. Carbon offsets were then placed on the MAC curve under three separate demand scenarios, five different offset scenarios and five different subprime scenarios. We find that subprime carbon will always lead to an overstatement of emissions reductions, and can lead to more volatile carbon prices, depending on the emissions reduction target and proportion of allowable offsets.

One source of uncertainly in this area is the modelling approach. More research is required on impacts of subprime carbon should be tested using other types of models, like CGE or integrated assessment models, in order to test whether the impacts are consistent and robust to different modelling techniques. Furthermore, the modelling technique used to measure the impacts of subprime carbon is highly sensitive to model assumptions, including the steepness of the MAC curve. Almost certainly, once a market for carbon is established with clear defined rules on the treatment of carbon offsets, potential impacts of subprime carbon will be easier to examine.

Research also needs to be done on developing a robust regulatory structure for Kyoto's project-based mechanism as well as other carbon offsets projects, with increasing scrutiny over the regulation of the executive board's ability to ensure the integrity of CDM and JI projects.

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