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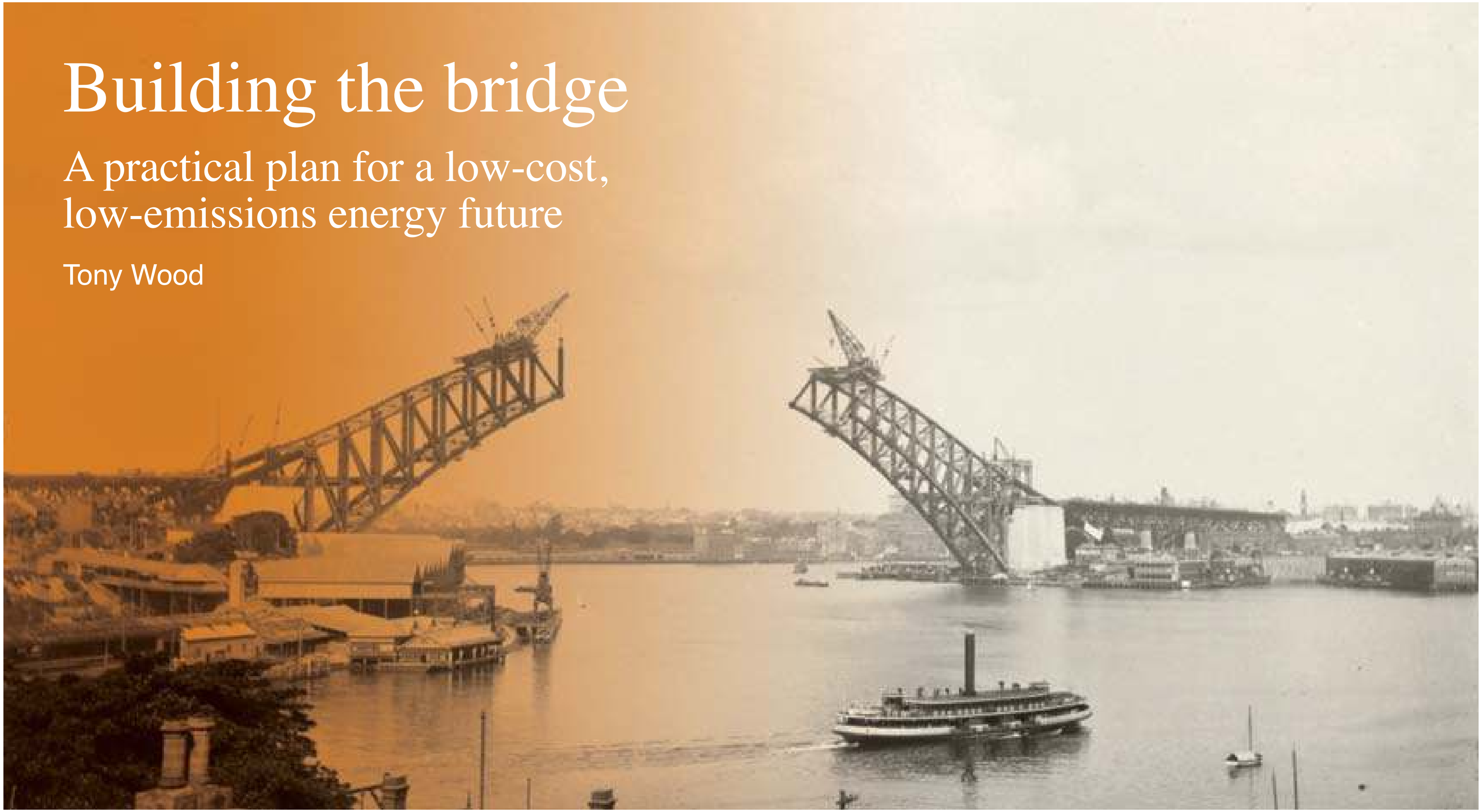

Building the bridge

A practical plan for a low-cost, low-emissions energy future

Tony Wood

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Overview

To meet long-term emissions reduction targets, Australia's electricity sector must be transformed in fewer than four decades. A market mechanism — an emissions trading scheme — is essential to make changes of this speed and scale. But as a recent Grattan report has shown, the market will not do it at lowest cost. Technologies that might produce large amounts of low-emissions electricity are still expensive and high-risk. The market's difficulty is making the best options commercially viable.

That is because early investors face high costs, low returns and the risk of competitors free-riding on their initiative. They require a reliable, long-term carbon price to underpin their investments. Yet the carbon price is inherently uncertain because it depends on the decisions of governments. For both these reasons, investment in low-emission technologies is and will remain critically inadequate.

Governments must address these market failures, beyond putting a price on carbon. They must provide the credible financial return and predictable policy settings that companies need to make substantial, risky investments. But how can they support new technologies without `picking winners' or, conversely, gambling that the market alone will do the job? This report sets out an innovative proposal to build a bridge between the current market and the market for low-emissions technologies Australia needs.

Here is how it would work: Government enters into long-term contracts with project developers to buy electricity at a price that makes low-emission projects viable. It awards contracts through a series of six-monthly auctions, held over 10 years. Competition to win contracts delivers the lowest price for low-emission power. Developers can invest knowing the contracts will be honoured irrespective of government policy on the carbon price. A 10-year timeframe and clear rules provide companies with a predictable investment environment, and multiple opportunities to invest. The scheme may produce about 5 per cent of Australia's power.

The auctions will award power contracts in specific technology categories. Over multiple rounds, technologies must deliver both low costs and show that their costs are falling. Those that do will gain more opportunities to build projects; those that do not will have opportunities withdrawn. The outcomes clarify the current uncertainty about which technologies will best meet Australia's long-term needs. It is too soon to punt on just one or two horses. Instead, government should pay to develop a portfolio of options from which a proven set of technologies can emerge.

Government should still fund technology R&D. But learning what works on the ground is the only way to identify the best mix for reliable, low-cost, low-emissions energy supply. The auction process gives companies the chance to gain practical deployment experience, and thereby to cross the bridge to commercial viability. Once technologies are viable, government should withdraw support, beyond a well-managed carbon price.

Driving innovative, low-cost technologies is a widely recognised problem in climate change policy. This scheme addresses that problem. It has a cost, but it frees up constrained investment and innovation now in order to avoid much greater cost in the long run.

Box 1 How the scheme would work

The principle: develop commercial options for a low-emissions energy future

The scheme enables companies to reduce the costs of several large-scale low-emissions power technologies. Long-term (20-year) contracts enable developers to build power projects that would not otherwise have been developed in the near term. Government does not offer any money upfront, but contracts to pay only when companies deliver low-emissions power. A series of auctions reveals how technology costs are changing over time. The best performing technologies can bid for the right to build more projects, while technologies that don't improve leave the scheme. Competition, not government, determines which technologies should be developed into a portfolio of credible technology options. From this point, energy companies can choose which options to use as they compete in the electricity market.

The nuts & bolts: a series of competitive auctions in technology-specific categories

Auctions in multiple categories (eg solar PV, bioenergy) are held every six months for 10 years. Contracts are awarded on price only. Auctions offer enough capacity for companies to learn by doing, and thereby reduce technology costs, but no more. Each round might auction 300 megawatts, or about 200,000 rooftop solar systems, across all categories.

Government begins the scheme by 'setting the field', that is, defining initial auction categories. After this, the size and number of categories are adjusted each round, according to pre-defined rules. Provided that winning bids deliver on the ground, technologies that demonstrate low cost, and a falling cost, will gain more opportunities to build projects. Those that have high cost, and do not reduce their bid price, will have their category shrunk, eventually to zero. New technologies can enter the scheme by bidding in a 'new entrant' category.

The contract structure reveals the cost of building projects. As Chapter 4 explores in detail, each contract offers the developer two payments. The first is a guaranteed carbon price. This changes over time, but in a predictable way. Government announces its value before each auction round. The second reflects costs that are specific to each technology. This is a payment on top of the electricity market price and its value is determined by bidding. Only companies that win a contract gain access to the guaranteed carbon price payment.

Auction schemes risk that companies will bid prices so low that they cannot deliver their project. There are several safeguards against this. Among others these include, firstly, that developers must obtain their project finance before bidding, subject of course to winning the auction. This way, bankers, not government, must scrutinise the project and determine whether or not it merits investment. Secondly, successful bidders must post a substantial bond against late or non-delivery of the project. Thirdly, firms have three months to conclude their financing and 12 months to commit to construction, or else they forfeit their contract.

A hypothetical case study:

Sundance, a company in the Concentrating Solar Power (CSP) business, decides to bid in the solar thermal auction category. For the current round, government has set the guaranteed carbon price starting at $35 per tonne, rising at 4 per cent per year. Sundance estimates that this will generate average revenue of about $33 per megawatt-hour over the next 20 years.

Before the auction, Sundance negotiates with its bankers and obtains a contract for the project finance it will need to build and run a 50 megawatt plant. To run at a profit, it estimates that over 20 years it will need to sell its electricity at about $128 per megawatt-hour above the average wholesale market price.

On auction day, no other solar project bids as low as the $128 premium — no one, that is, can produce solar thermal power more cheaply — so the company wins a contract in its category, worth approximately $128 + 33 = $161 per megawatt-hour for 20 years. Within five months Sundance has begun construction and within twenty months the new solar plant is supplying low-emissions power.

As time goes on, engineers make improvements to the construction process. Teething problems are encountered and overcome; with experience, Sundance and others learn how to do some things more efficiently. At the same time, international CSP technology suppliers find ways to raise the solar receiver’s temperature, making it more efficient. Over several auction rounds, competition in the solar thermal category pushes bids down to a total payment of $108 per megawatt-hour. The 16 per cent improvement in CSP bids is substantially greater than that achieved within the bioenergy power category over the same period. Accordingly, the solar thermal category increases and the bioenergy power category shrinks.

Separately, Australian company *DC/AC* has licensed a new battery technology, developed in Korea. DC/AC wants to pair its electrical storage technology with *Sailpower*, a prominent wind developer, improving its ability to respond to electricity demand. The cost of this project is not competitive with a normal wind farm, so the consortium bids for a contract in the ‘Open – on demand’ category, which requires projects to bid on price and the amount of time they will be available to generate electricity. In this round, the companies cannot secure a contract. Yet their investment in preparing a bid is not wasted. DC/AC can continue to develop the technology and bid in a later round.

Over time, several technologies will become commercially viable without the scheme, as their costs fall and the actual carbon price increases. Government’s role is over when companies like Sundance can match the prices of high-emission generators. After the existing contracts are concluded, Sundance and other generators must compete in the electricity market to provide reliable, affordable and low-emissions power.

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1. How we wrote this report

The 2012 Grattan report, *No easy choices: which way to Australia's energy future?*[1], concluded that the Commonwealth Government's Emissions Trading Scheme (ETS) alone is unlikely to provide the right mix of low-emission technologies to meet Australia's long-term energy needs. It argued, therefore, that government should intervene beyond putting a price on carbon in order to address barriers to efficiently developing low-cost, low-emissions electricity generation technologies.

This report, building on these findings, presents a practical proposal for how government should intervene to support the development of low-emissions technologies at the critical demonstration/early commercial stage. These are the technologies most likely to produce large amounts of low-cost, low-emissions electricity in the future. Many technologies stall at this stage due to the large capital investment required and/or the multiple risks, from new engineering challenges to gaining planning approvals.

To develop this proposal, we looked at three major policy approaches to low-emissions technology development that governments around the world have tried in the past. They are:

- Investment incentives, including grants and low-cost government loans,
- Feed-in revenue support schemes, such as feed-in tariffs, and
- Tradable green certificate schemes such as Australia's Renewable Energy Target.

A study of these approaches reveals that while some elements in them have worked well at reducing technology costs and risks, most have not. To be fair, most were not designed primarily for this purpose. Our proposal seeks to draw on the strengths of these approaches, while avoiding their pitfalls.

The *No easy choices* report identified several other market failures that also require government action beyond putting a price on carbon. Government should support primary research and development in energy technology, reform existing transmission network planning and management systems, map and disseminate resource information, remove existing subsidies, and streamline land-use planning and environmental regulations. However, these subjects are not covered in this report.

Chapter 2 sets out the rationale for why governments should intervene in low-emissions energy technology development. Chapter 3 sets out the principles that should guide policy in this area. Chapter 4 presents in detail our proposal for how governments should support development of low-emissions demonstration/early commercial technologies. Chapter 5 considers the consequences of implementing this scheme in the context of Australia's energy and climate change policy environment. Chapter 6 reviews the three major approaches to technology deployment that informed our proposal.

[1] Wood, *et al.* (2012)

2. Why government should intervene

From July 2012, the Government's *Clean Energy Future* package established a carbon price to enable Australia to meet its climate change targets and deploy low-cost, low-emissions technologies in the near term. Yet in order to develop, demonstrate and deploy the technologies that are likely to be lowest cost in the longer timeframe of meeting the climate change targets, further government action is essential.

The market cannot work properly unless government removes the barriers to deployment of several new technologies. The barriers include difficulties in transmission connection and government support for conventional, emissions-intensive technologies that is effectively a subsidy. Currently, government regulation of transmission distorts electricity generation markets against low emissions technologies and in favour of coal and gas generation.

Yet even if government removes these obstacles, it remains unlikely that enough capital will be invested in the short term to give any of the technologies a chance to deliver. The Australian Government reached a similar conclusion, stating in the recent *Clean Energy Future* policy package that:

> *The scale of the required transformation is large and the barriers to changes are high. There is a strong case for the Government to help by encouraging innovation in clean energy, particularly during the early stages of the transformation.*[2]

There are several reasons why this is so. Early investors face higher costs than followers. Finance costs are higher for technologies that are not well understood. Importantly, many of the challenges are local, that is, specific to building projects in Australia. New infrastructure, technical expertise, supply chains and regulatory frameworks all must be developed, imposing delays and costs on early movers. Resource mapping is inadequate and some technologies lack long-term community support.

Early movers get little reward for paying these higher costs. Unlike consumer electronics, for example, low-emissions power provides the same service to consumers as emissions-intensive electricity. Innovations do not earn more, and expensive intellectual property may not be defensible. What is more, early movers cannot bank the full value of projected higher long-term revenues for low emissions electricity because government policy on climate change and energy is inherently unreliable. The Grattan report *No easy choices: which way to Australia's energy future?*[3] analysed these difficulties in detail.

The report also assessed the performance of seven technologies that could generate very large amounts of electricity with near-

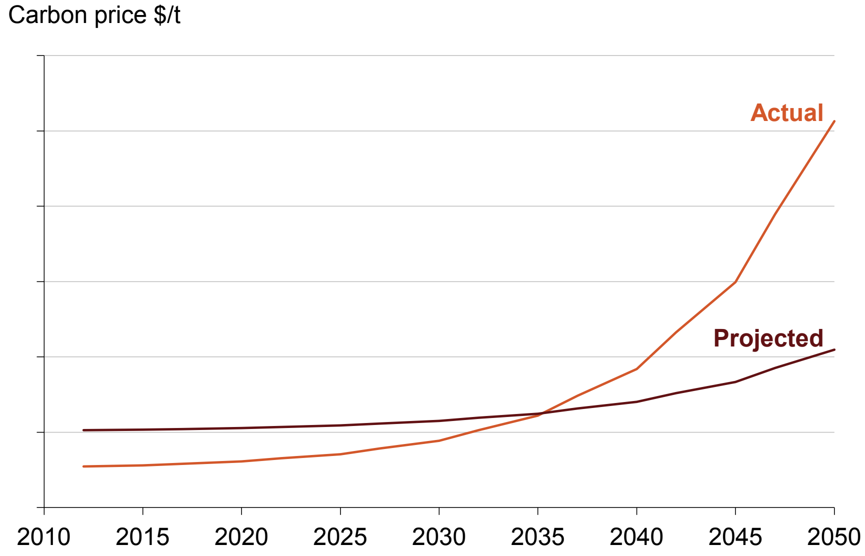
[2] Australian Government (2011)
[3] Wood, *et al.* (2012)

zero emissions, and asked what is needed for any to be deployed in Australia at large scale and sufficiently low cost. We found that the prospects of all are uncertain. It may be that none will be able to produce power at a cost similar to today's electricity over the timeframe for reducing emissions.

Also, because the carbon price is likely to be low for some time, largely because of political uncertainty around the policy, businesses are likely to invest in technologies that are more certain today (such as gas-fired power), but are unlikely to be optimal over the long-term. If that is the case, the real-world carbon price will need to increase steeply in later years as the urgency to address climate change increases. The risk is that emissions targets will have to be met at much higher cost over the long term, simply through a failure to encourage early innovation investment and capture its benefits (Figure 2.1).

The only way to respond to such uncertainty is to reduce the costs and risks of a range of technologies, developing a portfolio of low-emissions technology options that can be dynamically managed as events unfold.[4] This approach, common in industry, needs to be central to government intervention.

Figure 2.1 Near-term emissions are likely to be under-priced (conceptual illustration)



Source: Grattan Institute

The goal of the intervention must be to address the risks of investing in the carbon market and of being an early mover in an unproved technology. The risks will be minimised when they are shared between government and the private sector, depending on which party can manage them most effectively. Only government can address the credibility risk of the carbon market. It also has a well-recognised role to play in addressing early-mover technology risks. Other risks, such as project delivery and electricity market

[4] Sanden and Azar (2005)

risks, are best held by project developers and market participants respectively.

To date, government policies such as the Renewable Energy Target, capital grant programs and feed-in tariffs have not adequately addressed these risks. All of them have shortcomings, and, historically, they have been designed to achieve a number of other objectives. Chapter 6 assesses their strengths and weaknesses in detail.

In many cases existing policies only increase the cost of reaching our emissions reduction targets, once an ETS is in place. Instead, policies are needed that complement the ETS to deliver lowest cost, long-term reductions in greenhouse gas emissions. A range of Australian and international analyses have reached a similar conclusion but have not developed a detailed solution.[5] This report does so.

[5] Anadon, *et al.* (2001);Stern (2007);Garnaut (2008);IEA (2011);IPCC - Mitchell, *et al.* (2011);OECD (2011)

3. Principles for government intervention

3.1 What should government intervention look like?

Government support must focus on overcoming the uncertainty of the carbon market and the risks associated with early mover technologies. Support should be withdrawn when the market failures and technology barriers no longer exist. The benefits of support must outweigh the costs.

The scheme described in this report is targeted at demonstration and early-stage deployment, rather than at the R&D stage of technology development. Government should fund research and development separately.

Our proposal should lead to government taking on an appropriate level of risk, and as little else as possible. Project delivery, electricity market and some technology risks should be borne by the private sector.

3.2 How should the effectiveness of intervention be assessed?

Intervention must effectively address the problems, be low cost and provide a flexible, predictable framework for investment.

Here we set out four categories to guide government policy:

3.2.1 Efficiency and effectiveness of meeting the carbon emissions constraint in Australia

Intervention should:

- Address the carbon market credibility and early-mover technology risks.
- Provide incentives to companies to reduce costs in future.
- Avoid providing incentives for investment that would occur otherwise.
- Align with the multi-decade time horizon of climate change policy objectives. This means encouraging multiple investments and avoiding the boom/bust characteristic of many climate change policy mechanisms.
- Allocate support for greater volumes of deployment to technologies closest to commercial viability.
- Allow developers to determine the most appropriate scale for their projects.

3.2.2 Create and develop a portfolio of technology options

A range of low-emissions technology options should be created to hedge against future uncertainty. The portfolio should be robust under all plausible scenarios. Support should be expanded for emerging winning technologies and withdrawn as other technologies fail to progress and/or carbon market certainty increases.

3.2.3 Feasibility within government's broader policy framework

To be effective, the intervention must work within the central structure of the emissions trading scheme, including the fixed price and bounded price periods. Government should retain control over the total program cost so that it can manage its liability and avoid drastic action if technology costs change rapidly.

3.2.4 Predictability and flexibility of future government intervention:

Government must intervene because of the uncertainties surrounding future climate change policy and low-emissions energy technologies. As new information comes to light, government will need to respond flexibly, adjusting support as technology costs evolve. But investors should also be able to predict the government response with some confidence. There should be clear rules for how policy settings will change, and adequate lead-time for companies to re-position themselves.

4. Building the bridge: contracting for low cost, low emissions electricity

The proposal is to establish a series of auctions to be held every six months for 10 years. Through these, government will contract with a range of companies to generate electricity using low-emission technologies. Developers bid to provide the power, and the lowest bids succeed. The goal of the auction scheme is to reduce the costs and risks of several technologies at a speed and scale that would not be possible under a carbon-pricing regime alone.

Over 30 years of operation — 10 years of auctions with 20-year contracts — the scheme might produce about 5 per cent of Australia's electricity. The final cost to government will depend on many factors, including how technology costs change over time. Our analysis, based on forecast carbon prices and technology costs today, suggests an initial cost in the order of $150 million per year (not including any carbon capture and storage projects). However, the annual cost can be expected to fall over time, as technology costs drop and the carbon price rises. Over 30 years the total cost could be $4 billion, in present value terms.[6]

In developing our scheme we have drawn on an assessment of three major policy approaches to low-emissions technology development (set out in Chapter 6). None of them is perfect. Our proposal makes a number of trade-offs to meet the principles for government intervention described in Chapter 3.

[6] Discounting at 5.3%, the long-run average Government Bond rate

4.1 How will the scheme work?

To commence the program, the government or relevant body (see section 4.10) defines a number of initial low-emissions technology categories such as solar PV and bioenergy, and the size of each category at the outset. Auctions are held in each category every six months for ten years. Contracts are awarded on price only. Across all categories, each round might auction contracts worth a total of 300 megawatts, or the capacity of about 200,000 rooftop solar systems. Over ten years, the contracts may result in capacity that produces 5 per cent of Australia's power – in other words, not enough to distort the market in any material sense.

Each contract provides the developer with two payments for the power it produces. By paying only on output, government avoids the risks in project selection and delivery. This is better for all parties, because government lacks the skills and commercial motivation to identify the best projects, and has no role in construction or project management.

The first payment is a guaranteed forward carbon price. The guaranteed carbon price changes over time, such as rising by a fixed percentage each year, but in a predictable way, according to pre-defined rules. A new forward carbon price will be set for each new auction.

This payment is structured as a 'contract for difference', meaning that government pays the difference between the guaranteed price and the actual carbon price. If in later years the actual carbon price rises above the guaranteed carbon price, the developer must pay the difference back to government. This means that there are no windfall gains.

The second payment is a premium on top of the wholesale electricity price. The premium amount is fixed, so the amount received by the developer varies with the electricity market price.[7] The payments are described in more detail in section 4.5.

Once a contract is signed, government support for that project is locked in for the duration of the contract. But in subsequent auction rounds, the size and number of categories will change, according to several simple rules. Provided that winning bids deliver on the ground, the number of megawatts offered in each technology category varies based on two factors. These are:

- the absolute size of the premium, that is the amount over the wholesale price that a developer needs in order to sell electricity at a profit
- the rate at which the premium has fallen over multiple auctions.

Categories that perform well on these factors increase from round to round. Categories than do not are shrunk. In this way government can support the best performing technologies to emerge.

There are two 'open' categories that offer additional contracts to the technology-specific categories. Any participant can bid in their technology-specific category and any open category.

1. The 'scale' category permits companies to compete for additional megawatts of capacity. This may be attractive if they would benefit from building at larger scale than that which their category would otherwise allow.

2. The 'on demand' category offers an additional payment to technologies that can supply power when the market needs it. Developers would bid on price and their availability to respond to demand. Winners would be selected by combining the two bid types. Contracts would include a penalty for not meeting the availability that developers bid. This is likely to cover projects that include thermal or electric storage technologies, geothermal or CCS projects if or when they become viable.

Lastly, there is a 'new entrant' category that allows emerging technologies to enter the scheme, such as wave power. It is open to all technologies not already included in the scheme. A new entrant may obtain its own technology-specific category if it performs on the cost reduction criteria described above.

Before each auction, each company or consortium must advance its project to the point where there are very few remaining hurdles to clear before a contract can come into force and the project can commence. These 'conditions precedent' could include securing environmental approvals or planning permits. They should, however, be as few as possible and would not include securing financing. Project finance must be arranged ahead of the auction, subject to winning a contract. The goal is to ensure that bankers, rather than government, assess the commercial viability of the project.

[7] Government may choose to index the premium to inflation

The scheme includes several safeguards to protect against companies making unrealistic and undeliverable bids, unreasonable delays and other problems that may occur over long timeframes.

- Holding multiple auctions over 10 years means that companies will have several opportunities to obtain a contract. They do not need to bid as aggressively as they might in a single round auction.

- Companies can participate only if they pass a basic technical and commercial credibility test. As described above, a firm agreement for project finance is also required, meaning that bankers will perform the necessary due diligence.

- Winning projects must pay a substantial project bond if their bid is below a reserve price. Government can use all or part of the bond to penalise companies for failing to meet the conditions of their contract.

  Before each auction government publishes a reserve price in each category. The size of the bond increases as bids become more aggressive. A bid well below the reserve price will require a larger bond than one close to the reserve price.

- Winning projects will have no more than three months to reach financial close and satisfy any conditions precedent. They will have 12 months to commit to construction, or else they forfeit their contract and their bond.

- The contract will require companies to deliver a minimum amount of low-emissions electricity per year from an agreed date. If the project is not generating power by that date, government deducts penalty payments from the project bond. If the bond has been exhausted, the developer must then provide the low-emissions power by purchasing it on the market. The total 'grace' period for late delivery may continue for up to 24 months. Beyond this point government can choose to cancel the contract.

These conditions increase the financial cost of developing projects. This will be built into companies' bids.

There are many options for how the bidding mechanism itself could be designed. These would need to be reviewed carefully, because auction design can materially influence how effective the scheme will be.

4.2 Why auctions?

An auction-based scheme can meet several important goals in a way that other policy approaches do not.[8]

First, it can achieve long-term credibility and healthy returns. If government is to accelerate higher-risk technology development and deployment, it needs to offer companies some long-run security to offset the higher risks. Feed-in schemes do this, which is why they have produced more deployment than capital grants or market-based schemes, such as Australia's Renewable Energy Target. An auction scheme can achieve this by providing long-

[8] Chapter 6 provides a detailed review of the main policy approaches low-emissions technology deployment and how real schemes around the world have performed against the principles for government intervention set out in Chapter 3.

term contracts and holding regular auction rounds, offering firms numerous opportunities to win government support.

Second, it avoids government having to estimate the best rate of support for each technology. Competitive bidding pushes developers to reveal the minimum price they need to build a project. It also allows government to obtain the lowest costs over time. Auctions have produced very low prices in several jurisdictions, including the UK, South Africa, India, California and Brazil.[9] By contrast, most feed-in schemes do not apply the same downward pressure to technology costs.[10]

Third, government is able to manage the total cost of the policy. In an auction scheme, government can manage how much financial exposure it takes from round to round, and can announce adjustments to the scheme, according to rules, several rounds in advance. By contrast, feed-in schemes leave governments vulnerable to the total cost rapidly escalating out of control.[11] Once this happens governments clamp down on spending and the market swings quickly from boom to bust, taking investor confidence with it.

Fourth, auctions can be adapted comparatively easily to support a range of technologies at different stages of development. By contrast, manipulating market-based schemes to develop multiple technologies has proved to be at best difficult, at worst disastrous. Modifying feed-in schemes to offer support in several technology categories has proved more successful, but this increases complexity and government's vulnerability to cost escalation by a multiple factor.

Auctions are not without risks. There is a danger that developers will bid unrealistically low prices to win a contract, then find they are unable to deliver their project on time, or at all. Many scheme have faced this problem, including grant tender programs in Australia and competitive bidding programs in China, the UK, California and, potentially, Brazil and India.[12]

It is widely agreed that a substantial financial penalty can help to guard against unrealistic bidding. We have included this device — a project bond — into the scheme outlined in this chapter, together with several other measures. In 2011 the California Public Utilities Commission introduced a bond payment into its renewable energy auction system, as a means to limit 'contract failure'. Brazil, similarly, has introduced a bond equal to five per cent of the estimated total project cost.[13] We note, however, that this approach is yet to be empirically tested.[14]

[9] UK: Non-Fossil Fuel Obligation scheme, South Africa: Renewable Energy Independent Power Producer Procurement Programme, India: Jawaharlal Nehru National Solar Mission, California: Renewable Auction Mechanism, Brazil: Renewable Energy Auction scheme.

[10] While feed-in schemes do not promote competition between project developers, it is thought that they do catalyse competition further up the supply chain, for instance between equipment suppliers or construction companies

[11] This can be true even where safeguards are employed, like capping capacity or implementing a system of automatically falling tariffs. See Chapter 6 for details.

[12] Kreycik*, et al.* (2011a); Haas*, et al.* (2011);US PREF (2012); pers comm, Asian Development Bank (2012).

[13] US PREF (2012)

[14] California Public Utilities Commission (2010)

4.3 Why is the program designed in the way it is?

The scheme is the result of several trade-offs between effectiveness, cost and complexity. It aims to balance risk between the public and private sectors, by allocating risks to the parties best able to manage them.

Table 4.1, overleaf, sets out how the proposed scheme lines up against the principles for government support described in Chapter 3. The major policy alternatives are summarised in similar tables in Chapter 6.

Table 4.1 Summary of auction scheme strengths and weaknesses

	Strengths	Weaknesses
Efficiency & effectiveness	Long-term 'feed-in type' contracts support technology development. The two contracted payments address carbon market and technology spillover risks. Frequent, competitive auctions allow government to avoid estimating the best support rate, obtain the lowest costs possible and observe how costs are changing over time Government can see when to withdraw support: bids will approach zero as the technology becomes viable under the carbon price alone Multiple safeguards against late or non-delivery of projects, a major flaw in auction-type schemes	Multiple technology-specific auction categories may mean limited competition Safeguards such as these are yet to be empirically proven
Portfolio of options	Multiple categories support a range of technologies. New or emerging technologies can bid to enter the scheme Pre-defined rules adjust the auction categories over multiple rounds, offering more support to performing technologies, less to those that do not reduce their cost Developers have an incentive to produce projects that can meet variable electricity demand, because they bear electricity market risk	Developers' exposure to electricity market risk may increase the cost of finance and favour large incumbents Government must pre-select the initial technology categories
Feasibility	Can work with an Emissions Trading Scheme	Will depress the carbon price, because by supporting projects government helps the carbon market to achieve its target
Predictability & flexibility	Government does not select projects ahead of delivery 10 year timeframe provides a stable, credible investment environment with multiple opportunities for companies to win contracts	

4.4 How should the contracts be structured?

Each contract offers the developer two payments for electricity generated and accepted by the system operator. The first is a guaranteed carbon price that is, at least initially, higher than the actual carbon price in the market. The second, a payment on top of the electricity market price, reflects the costs each technology faces in order to produce power. Developers compete on the second payment, that is, they compete to offer the lowest price for a given technology. Winning a contract gives them access to the price that they bid and the guaranteed carbon price. Let's look at these two payments in turn.

Related to the first payment, developers will not invest in low-emission technologies as long as they face the risk that the government will not take the decisions that ensure the actual carbon price continues to rise. A low carbon price means that low-emissions technologies cannot compete with traditional sources of electricity generation.

To overcome this problem, the government offers a contract for difference between the actual carbon price and a guaranteed forward carbon price, announced and updated at each auction. If in later years the actual carbon price rises above the guaranteed carbon price, the developer must pay the difference back to government. The price will change over time but in a guaranteed way. Payment is calculated based on electricity sold at the market's average pool emissions intensity, to reflect the steadily tightening emissions constraint (part of the emissions trading scheme).

The second payment is a premium on the wholesale market price paid to a developer to compensate for the high cost and technology spillover risks in deploying low-emissions power technology. Developers bid for the payment in a single reverse auction (meaning the lowest bid succeeds). Paying a premium on the wholesale market price gives the developer an ongoing incentive to generate electricity when the market price is high, that is when the consumers need it most. Under this approach, developers bear the risk that the market price will be low, which they would not in a fixed rate scheme.

4.5 How would a range of low-emissions technology options be maintained?

The auction scheme is intended to create and develop a portfolio of low-emission technologies. In other words, support increases when technologies are performing well and tapers off if the rate of cost reduction slows. That might happen because adaptation to Australian conditions has been achieved, and the underlying technology cost is global in nature.

This approach also can tailor contractual arrangements to suit the characteristics of specific technologies and avoids a winner takes all approach. The downside is that the government is pre-selecting the 'winning' technology categories, at least for the first few rounds until clear information emerges from the market. This is a necessary compromise.

4.6 How would support for specific technologies be ended?

Once a contract is signed, support for that project is locked-in for the duration of the contract. Over multiple auction rounds, technologies should continue to be supported while they reduce their costs and show potential for further reductions. A spread of low-emission technologies should be developed and maintained.

Support for a specific technology should be withdrawn at one of two points, whichever happens first: when the costs of technologies cease to fall, or when the rising actual carbon price means a premium is no longer necessary because the technology is now commercially viable.

Many policy support mechanisms become unstable or face criticism when they are wound down or withdrawn, even when these decisions have been flagged in advance. The credibility of this proposal depends on intervening when it is justified, as described in this report, and equally, withdrawing support in line with pre-defined rules.

4.7 What would be the initial auction categories?

The initial technology-specific categories should meet several criteria. The technologies should:

- show potential to make a material contribution to a low-emissions electricity future for Australia
- be at the demonstration or early commercial stage of development
- have potential for absolute and relative cost reduction
- be reasonably diverse, so that Australia keeps its low-emissions technology options open. Other technologies may enter the scheme through the 'new entrant' category.

In our view, the initial categories should be as follows:

- solar PV
- concentrating solar power (solar thermal)
- wind power[15]
- carbon capture and storage
- open category — 'scale'
- open category — 'on demand'
- the new entrants category.

4.8 The special case of carbon capture and storage

As well as sharing the deployment challenges of the above technologies, carbon capture and storage (CCS) faces two

[15] Wind power is widely considered to be a mature or close-to mature technology that has limited prospects for major cost reductions. We have included it as an initial category, however, because wind power is currently the cheapest large-scale low-emissions power technology and we cannot rule out major innovations in the sector. If it does not reduce its costs, the wind power category would be reduced down to zero.

additional, major barriers. The first is the scale required to achieve commercial viability. The second is the complexity of the CCS supply chain, which combines power generation, capturing CO_2 emissions, liquid CO_2 transport and geological storage.

The first issue means that the size of the investment needed is so great that it is almost always a ‘bet the company’ decision. This leaves few serious proponents standing. As a result, the rate of learning-by-doing will be much slower, especially if it is in just one country. Moreover, the size of CCS projects means they could dominate and distort the entire scheme. The second issue means that multiple companies from different industries need to be involved. It can be challenging for all the partners to negotiate mutually satisfactory commercial arrangements.

Therefore, under the auction scheme proposal:

- Government calls for bids for CCS as per the other categories in this paper, but a six-monthly repetition of auctions is not assured. The economies of CCS scale suggest that the amount of power needed to be auctioned would be at least 500 megawatts, and therefore unlikely to attract regular bidders.
- Government actively considers equity or government-backed debt for the first CCS project(s).
- Government establishes an authority to act as a risk-clearing house by making contractual arrangements easier across the CCS supply chain.

4.9 How are risks addressed?

Risk is central to the rationale for the proposed government intervention. Risk often prevents investment from taking place. Whilst some risks can be reduced, others need to be allocated to and managed by the parties best positioned to do so. Table 4.2 identifies how risks are addressed under the proposed scheme.

Table 4.2 How major risks are addressed

Risks to government	Response
Projects are not delivered on time or at all	Only credible bidders with finance in place will be permitted to bid. Construction risk rests with the proponent. This is entirely appropriate for technologies at this stage of development.
Technology costs do not fall	Competitive bidding puts significant pressure on developers to reveal the true cost of building projects. If the cost does not fall then the gains remaining are probably few. The auction categories are adjusted after each round, to favour the best performing technologies, and decrease the opportunities for those that do not reduce their cost.
Projects are either too small or too large	Developers determine the optimal scale for each technology.
Distorting the existing electricity market	Companies still bear electricity market risk, so they are more likely to respond to market signals. Overall the scheme is not large. It may produce up to five per cent of Australia's electricity.

Risks to developers	Response
Technology spillover risk	Government compensates developers by paying a premium for low-emissions power, determined by the market.
Carbon policy risk	Government takes the carbon policy risk by offering a guaranteed forward carbon price. Government is best placed to accept and manage carbon policy risk, at least while the market gains credibility.
Sovereign risk	Long-term contracts underpin the payments above.
Potential for boom-bust cycle	Commitment to hold auctions for 10 years, with adjustments made using clear, pre-defined rules and announced well in advance.
Electricity market risk	This is best managed by the proponent.

4.10 Would the benefits outweigh the costs?

The scheme seeks to transform Australia's electricity sector at a lower cost than would have been otherwise achieved. Addressing identified market failures and barriers will provide market credibility and predictability that will enable investment in the low-emission technologies most likely to deliver emissions reduction in the long term at lowest cost. Electricity produced through a series of reverse auctions is likely to produce lower costs than governments could achieve through direct grants or setting prices, since governments cannot be in a position to know future technology costs.[16] Failure to develop a suite of low-emissions technology options is likely to produce far higher costs in the long

[16] See Grattan Institute's 2011 report, *Learning the hard way: Australia's policies to reduce emissions.* Daley, *et al.* (2011a)

run. As emissions constraints tighten, and the price of carbon rises, the cheapest alternative to coal, gas-fired generation, is also likely to become too expensive and too emissions-intensive.

The proposal imposes two costs on government. The first occurs when the actual carbon price under the ETS remains below the strike price (or contracted forward carbon price) set at the time of the auction. The net cost over the length of the contract will be minimised and could be even negative if, over time, the carbon price rises above the strike price. The second cost is the premium successfully bid at each auction.

As outlined above, the final cost to government will depend on many factors. Our analysis, based on the information that we have today, suggests costs in the order of $150 million per year, not including any CCS projects. However, the annual cost can be expected to fall over time, as technology costs drop and the actual carbon price rises. Over 30 years the total cost could be about $4 billion, in present value terms.[17]

4.11 How might the proposal be funded?

Industry and political proponents will often call for 'certainty'. These calls usually reflect the vested commercial interest of the proponent. In the case of climate change policy, what investors need is forward credibility, flexibility and predictability.

This proposal should not be funded, therefore, as part of the annual budget allocation process or even directly by government. The experience of rebates and subsidies in Australia and around the world reveals the dangers of this approach.[18] Funding Australia's Renewable Energy Target (RET) program through regulated energy charges has been more effective in this regard. The better approach would be to replicate the RET's funding mechanism, a levy on electricity consumers, or to use revenue from the auction of permits under the ETS.

The Clean Energy Finance Corporation (CEFC) might administer part of this funding. For example, the Corporation could create and manage a Green Investment Bond that would provide funds to invest in successful projects under this program.

4.12 What should be the governance structure?

The Garnaut Review proposed a Low-Emissions Innovation Council.[19] An independent body with these responsibilities, such as the CEFC, would be the best way to achieve the appropriate result.

4.13 How does the proposal stand up to criticism?

The following responds to several possible criticisms of this scheme:

[17] We used a discount rate of 5.3%, the long-run average Government Bond rate, to estimate the present value cost.

[18] Daley, *et al.* (2011a)
[19] Garnaut (2011b)

Table 4.3 Potential criticisms and responses

Principle or issue	Design element or response
This is just the government picking winners	There is a necessary and valid compromise in which the government selects technology categories most likely to succeed based on transparent data. Winners will emerge and that is ultimately the ideal outcome.
Projects can fail to deliver capacity and this represents a risk not covered by the proposal	Some risks should be retained by proponents, and certainly for technologies at the demonstration and early deployment stages. A number of safeguards have been included specifically to increase project deliverability.
Companies don't know how government will respond to unexpected or changing financial circumstances	The government will need to clearly communicate the extent of its financial commitment and the conditions under which it would review the scheme
The proposal could waste money, since the government cannot know forward costs and other key delivery parameters	The reverse auction process should minimise exposure to windfall gains. Government should take some technology spillover risk, because it creates a market failure.
This proposal will be costly to consumers, since the supported technologies will push out the cheaper gas solution to emissions reduction	The objective is to reduce the long-term cost of emissions abatement. Gas is likely to be cheaper in the short term and under mild emissions constraints, but is not likely to be the lowest cost in the longer term as gas markets change and emissions constraints tighten.

5. Implications in context

5.1 How will the proposal fit within the broader energy and climate change policy framework?

The government intervention recommended in this report is designed to address market failures and barriers that, if not addressed, would eventually lead to much higher energy costs in Australia. The proposal specifically addresses those market failures and barriers that arise from the introduction of the current Government's ETS and associated governance structures. However, there is also a range of policies and programs in existence, or proposed, that provide a complex policy environment that must be considered. Otherwise, the recommendation in this report will remain of theoretical interest only. A change of government would lead to changes in the policy environment, bringing a different set of considerations.

Recent revised forecasts by AEMO of NEM electricity demand for the 10 years beyond 2012 indicate a softening against previous projections.[20] This may have significant implications for additional generation capacity required and for the amount of emissions reduction to meet Australia's five per cent target by 2020. Our proposal will influence the mix of technologies that will be required over this period. This is an inevitable consequence of beginning the transition to a low-emissions energy future.

5.2 The emissions trading scheme context

Once emissions are capped through an emissions trading scheme, there is no case to support technologies beyond addressing the market and system failures identified in Grattan Institute's previous report *No easy choices: which way to Australia's energy future?*[21] The necessary and sufficient elements of this approach are:

- Setting emissions caps with environmental integrity and forward predictability, broadly as envisaged by the Climate Change Authority.
- Maintaining and expanding exploration and mapping of resource quality and quantity for particular technologies such as geothermal energy and CO_2 storage.
- Addressing barriers to coordination and planning of transmission investment decisions related to more remote renewable energy sources and integration of distributed generation sources with distribution grids.
- Support for research and development in areas of national interest. Grattan's previous report expanded a little on this topic. Such support should fit broadly within the remit of the Government's Australian Renewable Energy Agency

[20] Australian Energy Market Operator (AEMO) (2012)

[21] Wood, *et al.* (2012)

(ARENA), although including all low-emission technologies would be a good idea.

- The proposed intervention to support low-emission technologies at the demonstration and early deployment stages as described in this report. Chapter 4 describes this proposal in detail, and refers to a governance structure that could include the Clean Energy Finance Corporation.

In the absence of carbon pricing, the Renewable Energy Target has delivered significant abatement at reasonable cost.[22] Its existing arrangements should be 'grandfathered', or preserved, to honour existing contractual and related investment decisions made under this program. This is necessary to prevent the kind of unpredictable tampering and adjustments to support programs criticised in Grattan Institute's 2011 report, *Learning the hard way: Australia's policies to reduce emissions.*[23]

5.3 The Direct Action context

The Federal Opposition has proposed to establish an Emissions Reduction Fund as the central element in its Direct Action Plan if it wins government. While the scheme is not yet fully detailed, the proposal uses a form of tendering to enable project proponents to bid for emissions reduction, presumably at lowest cost. This process will use bidding to facilitate price discovery, effectively establishing a carbon price.

The scheme proposed in this report, drawing on the lessons of a range of programs adopted in Australia and overseas, could work with the Emissions Reduction Fund and support the efficient achievement of its objective.

[22] Daley*, et al.* (2011a)
[23] Ibid.

6. The policy alternatives — a detailed assessment

In developing the policy proposal in this report, we reviewed the major approaches to low-emission technology development and deployment and how they have been implemented around the world. They are:

- investment incentives (capital grants, low-cost debt or equity)
- feed-in revenue support (such as feed-in tariff schemes)
- tradable green certificate revenue support (market-mechanisms such as Australia's Renewable Energy Target).

This chapter examines their strengths and weaknesses in detail and shows how each lines up against the principles for government intervention outlined in Chapter 3. The analysis has led us to conclude that an auction scheme for long-term contracts offers the best mechanism to develop a range of low-cost, low-emission technology options.

6.1 Lessons learned – there are no easy choices

Grattan's previous report, *No easy choices: which way to Australia's energy future?*, concluded that there are no quick wins or easy choices among low-emissions energy technologies with the potential to make a material contribution to a future low-emission energy mix.[24] It is possible that none of them, alone, will produce power at a scale and at costs similar to our current electricity supply.

When it comes to technology development policy, again, there are no easy choices. None of the three approaches is perfect. Inevitably, any policy must make trade-offs between effectiveness, cost and complexity. Each shares risk between the public and private sectors in a different way. The following lessons emerge from our assessment:

- Early developers of low-emissions technologies face a serious risk of technology spillover: when one company benefits from the innovations of another without having to pay for them. As this chapter outlines, there are several ways to compensate developers for this risk.
- Developers also need a predictable revenue stream to address the carbon policy risk – the risk that the price will not rise because future government decisions will not continue to tighten the constraint on carbon emissions.
- None of the approaches naturally produces technology diversity. All must be substantially modified in order to allow a range of technology options to emerge. Invariably these modifications increase scheme complexity and the risk of unintended outcomes.
- All three approaches risk compromising the emissions trading scheme because they deliver technologies that reduce emissions, thereby depressing the carbon price and changing investment incentives within the ETS.

[24] Wood, *et al.* (2012)

- Long-term certainty and transparent, predictable management can significantly reduce the cost of project development. But governments have a chequered history implementing schemes to support low-emissions technology. Often they make unpredictable direct changes and introduce other programs that have indirect consequences.

6.2 There are just a few approaches available to policymakers

Globally, many government schemes support the deployment of new electricity generation technologies. These include feed-in tariffs in many European countries, portfolio standards in the USA and the Renewable Energy Target in Australia. Most schemes have focussed on renewable energy.

While the policies vary, essentially there are two ways in which governments can provide additional financial support to companies: either before the project is built to reduce the initial capital cost, or after it begins to operate, as extra revenue (or support for operational costs).

Within these categories, the main policy approaches are investment incentives, feed-in revenue support and tradable green certificate revenue support. They are described in the following sections.

Several other policy tools are not included in our analysis. Tax credits and concessions transfer wealth from government to developer, but have limited scope to address risks for immature technologies that cannot earn sufficient revenue from the electricity market. In this sense tax measures do not always provide additional financial support.[25] Similarly, loan guarantees, risk insurance or pre-permitting of development sites may work as complementary policies, but are rarely the main game. They do not transfer additional funding to developers and are seldom implemented on their own.

Investment incentives (capital grants, low-cost debt and equity)

This approach injects government capital into energy projects in order to reduce developer costs. Grants — paid either on promise or on performance, as a prize — transfer public funds to the private sector and require no financial return. Low-cost government loans (debt) and direct ownership (equity) do require a return, but usually on more favourable terms than private-sector finance.

Within these categories there are many structures that can be applied to individual deals, such broad-based US Treasury grants and solar PV-specific capital subsidies in China and Japan.[26] Grants are very often provided through competitive tender. Australian examples include the Low Emissions Technology Development Fund, the Energy Technology Innovation Strategy, CCS Flagships and Solar Flagships.

Over the last 40 years or so, low-cost 'soft' loan programs have been tried in many countries, such as Germany, the Netherlands

[25] It is true that production tax credits were a significant driver of US wind power, arguably a mature energy technology, for several years. In the last decade, however, many US states have complemented the Federal tax credit with a TGC revenue support scheme, usually called a Renewable Portfolio Standard.
[26] Productivity Commission (2011)

and South Korea.[27] The United Kingdom recently established the Green Investment Bank with £3 billion funding to invest in a range of energy and other 'green' projects. Australia's $10 billion Clean Energy Finance Corporation (CEFC) may well take a similar path, aiming to achieve a portfolio-level return about equal to the government bond rate.[28]

Feed-in revenue support schemes

Government and developer enter into a (usually fixed-term) contract that provides a payment for each unit of electricity produced. This requires government to either select projects to fund or let contracts on a first-come, first-served basis. The contract may offer the developer a fixed rate or variable rate of additional revenue.

Revenue support agreements may be accompanied by an obligation on the retailer, energy utility or regulated network operator to purchase the power produced. Support is usually framed within a long-term contract of 15 to 25 years. Funding may come from the government budget — from taxpayers — or from all electricity consumers via regulated network charges.

The primary examples are the feed-in tariff (fixed) & feed-in premium (variable). Under a feed-in tariff, generators receive a constant dollar rate per megawatt-hour produced, irrespective of the wholesale electricity market price. A Feed-in Premium offers a payment above the wholesale price. This could be a fixed amount added to the wholesale price or a percentage of the wholesale price. Usually the term 'Feed-in Tariff' is used specifically for small-scale distributed generation schemes, and 'off-take agreement' is used to refer to large-scale generation.

Feed-in revenue support schemes have been implemented in many countries around the world, particularly in Europe. Examples include the Erneuerbare Energien Gesetz (German feed-in law), Régimen Especial de Producción de Energía Eléctrica (Spanish feed-in scheme) and the Conto energia (Italian feed-in scheme). Several small-scale generation feed-in schemes operate in Australian states.

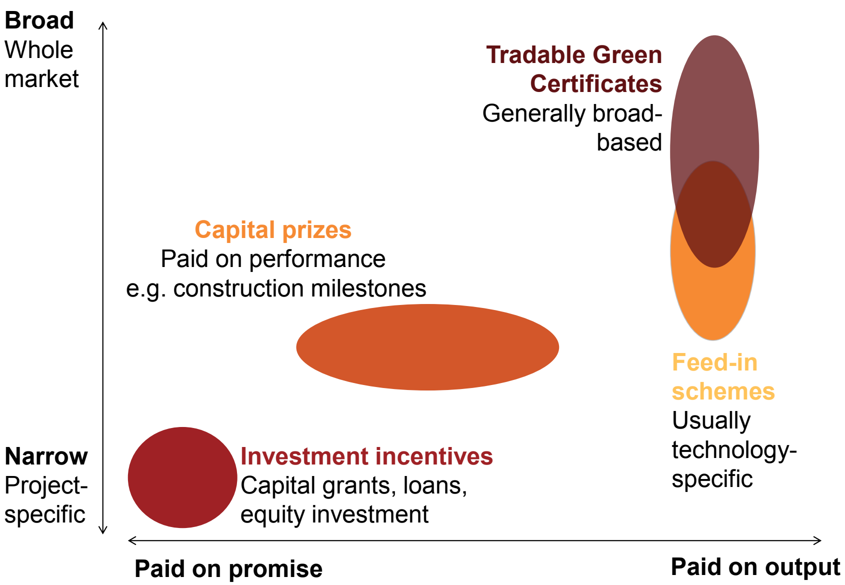
Tradeable Green Certificate (TGC) revenue support schemes

Like feed-in schemes, this approach provides a payment per unit of electricity produced, but here a purpose-built market sets the price for support. Licensed electricity suppliers are legally obliged to acquire a proportion of their power from a particular source, usually renewable energy. Suppliers meet their obligation by acquiring 'green' certificates from licensed renewable energy generators. The certificates correspond to megawatt-hours of renewable electricity supplied to the electricity market. The certificates can be traded on a separate market and are funded by electricity consumers. Government imposes a penalty charge on power suppliers who do not meet their quota.

Schemes of this type have had various names, such as Renewable Energy Target (Australia), Renewables Obligation (UK), Renewable Portfolio Standard (multiple US states). All are variants of the same mechanism.

[27] de Jaeger and Rathmann (2008);Productivity Commission (2011)
[28] Broadly, this was the recommendation of the recently completed CEFC Expert Review, Clean Energy Finance Corporation (2012)

Figure 6.1 Differences in technology support instruments



Source: Grattan Institute

Figure 6.1 illustrates how the instruments vary in their breadth of coverage and timing of payment. These differences alter the way costs and risks are shared between private developers and public funders (who are electricity consumers or taxpayers). At one end of the spectrum, capital grants may be paid to specific developers prior to project commencement, requiring government to take the risk of assessing the project ahead of delivery. At the other end, a tradeable green certificate scheme only rewards renewable electricity production, requiring developers to carry all the risks of developing a project before incentives are available to them.

6.3 There is limited knowledge about which approach is best at reducing technology costs and risks

The primary goal of practically all technology-support schemes has been to increase renewable energy generation. Usually this follows from an aspirational 'green' target, such as '20% of electricity supply from renewable energy by 2020', versions of which many governments have adopted. The success or failure of these schemes is judged against two criteria — the quantity of new capacity deployed and the total cost incurred by government or consumers. In combination these are sometimes called *static efficiency* — the cost performance of the policy as measured against a fixed capacity target.

By contrast *dynamic efficiency*, the change in cost performance over time, has received much less attention. There is far less evidence about which policy instruments are most effective at reducing technology costs and risks.

The reason is that cost-reduction has not been articulated as the major policy objective. As a consequence, around the world there has been little effort to compile and publish the data needed to assess changes in technology costs and risks. The information is dispersed and largely in private hands. Often it is commercially sensitive.

Even if the data were widely available, it is difficult to compare the cost-reduction performance of policies on a dollar-for-dollar basis. Inevitably there are aspects that make each scheme different to others that operated at various times in a range of countries. Influences range from unique engineering or planning issues at the individual project level, to changes in global technology markets and the impacts of each country's broader policy environment. There is little by way of direct evidence with which to judge dynamic efficiency outcomes.

6.4 A practical assessment of the options

The primary challenge in low-emission electricity technology development at demonstration/early commercial stage is how best to create or increase competition and learning-by-doing. Companies need to learn how to push down their costs at project level and in the supply chain, in processes and equipment. They learn most through building projects in a competitive environment.[29] This objective must be balanced with the public interest, which is to maximise the efficiency of public funding and minimise unintended consequences.

The remainder of this chapter is given over to assessing the relative strengths and weaknesses of the major policy options. In view of the difficulties described above we have taken a practical approach, focussing on the balance between public and private risk and using the principles for government intervention set out in Chapter 3. They are:

- Efficiency and effectiveness in addressing the targeted risks
- Capacity to develop a portfolio of options,
- Feasibility within the broader policy framework, and
- Predictability and flexibility.

[29] Menanteau, *et al.* (2003);Bergek and Jacobsson (2010);del Rio Gonzalez (2011)

6.5 Investment incentives: grants, low-cost debt & equity

Table 6.1 Summary of investment incentives strengths and weaknesses

		Strengths	Weaknesses	Design options to improve weaknesses
Efficiency & effectiveness	*General*	Can address technology spillover risk Upfront payment reduces the impact of different discount rates in government and the private sector	Upfront payment does not address ongoing carbon policy risk and exposes government project selection and delivery risks	Selection risk: Require long-term power-purchase agreement as a condition of funding Delivery risk: Project bonds or warranties to provide a strong incentive to deliver projects on time and on budget. Deadline for committing to construction
	Grants		Grant tender programs have not produced deployment at large scale	Single grant: payments spread over a series of project hurdles (gateways or prizes) Grant program: multiple funding rounds and off-budget funding to increase certainty
	Low-cost debt	Can fill gaps or lower costs in private sector debt financing Government can cross-subsidise less-developed technologies with returns from other projects while maintaining a viable return across the portfolio	Low-cost loans may contribute to large-scale deployment, but probably are most effective in conjunction with other support policies Risk of crowding-out private sector investment if support is offered on a commercial basis	Government can rely on private sector for project selection, eg by co-investing on the same terms as a lead investor or investing through a third party-managed fund
	Low-cost equity	May be effective where the risks are too great for the private sector to invest (eg initial CCS or nuclear power plants)	Unattractive if debt funding is commercially attractive. Government bears greater risk and developers face a higher cost of finance	
Portfolio of options			Does not produce a portfolio of technologies unless government explicitly chooses the technologies and projects	
Feasibility		Can work with an ETS	Will depress the carbon price	
Predictability & flexibility		Upfront payment removes policy risk for successful projects	Risk of disruptive change to the overall program, because government risk is high and program funding is on-budget	

6.5.1 Overall assessment of investment incentives

Investment incentive schemes reduce the capital burden on private sector developers, making projects more affordable. They have often been a part of a package that includes other measures, such as revenue support, rebates or tax concessions. In this context, capital support schemes may help to reduce the cost of project finance and thereby the overall cost of technology support.

Yet they are not well suited to reducing costs and risks for technologies at demonstration or early commercial stage. Providing upfront capital, as a grant, a loan or for equity does not easily compensate developers for ongoing carbon market price risk — the most significant market failure that we seek to address. It can compensate developers for technology spillover risk -- another major objective – but it also exposes government to substantial project-related risks.

Grants and prizes for energy technology projects are likely to be most effective at the R&D stage, where the scale of projects, barriers to entry and the amount of funding required are lower. Debt instruments may help to address gaps in private financing, to leverage private finance or to efficiently reduce the cost of funding projects with a revenue support mechanism. Government equity may be necessary where other sources of funding are not viable. This is most likely for initial CCS or nuclear power projects, where the scale and risk combination may be too great for private investors. Yet as described below, capital grant schemes have been plagued by various combinations of poor design and implementation.

6.5.2 Efficiency and effectiveness

Risks are allocated to the parties least able to manage them

An investment incentive can compensate developers for knowledge spillovers that may occur if they move quickly on a new technology. Yet the approach leaves developers with carbon policy risk for the life of their project. It also requires government to select the best projects and to risk supporting projects that may or may not be delivered to specification, on time and on budget.

This is the exact opposite of what is needed. Ideally, government should bear the carbon policy risk and developers the risks in project selection and delivery. Government usually lacks the skills and commercial motivation to identify the best projects. It also has little or no control over the detail in construction and project management.

Grant tender programs have not produced deployment at large scale

In theory governments can use a competitive tender to limit their exposure to project selection risk. Examples of success range from roads to consulting services. For these goods and services there is already a competitive market and government has a fair idea of what constitutes a good price.

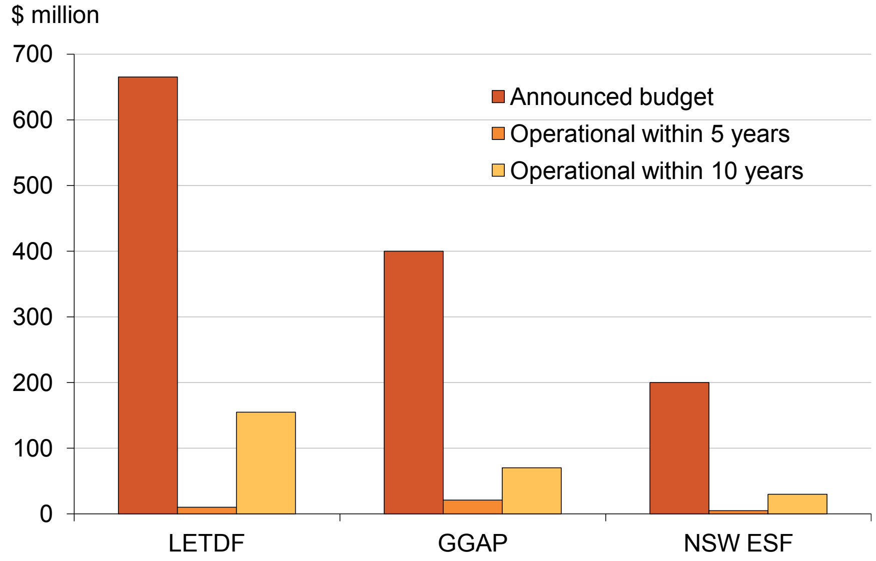
Yet when it comes to energy projects and other forms of carbon emissions abatement, grant tendering programs have performed lamentably. More often than not they have produced long delays or outright project failures.[30] Energy and low-emissions projects

[30] Daley, *et al.* (2011a)

involve new technologies and complex projects for which there are no benchmarks to judge whether a bid is realistic. Figure 6.2 shows that in Australian technology grant programs, winning projects suffered long delays and frequently did not proceed at all. In these programs, five years after the tender was awarded an average of just 3 per cent of total funding had produced operational projects. After ten years the average was only 18 per cent.

A range of design and implementation problems produces delays. First, multiple, complex and at times unrealistic assessment criteria make it difficult for developers to prepare bids and for government to select the winners.[31] Most of the schemes that Grattan Institute reviewed in 2011 did not award tenders until two to three years after bidding closed.[32] Several more years were then needed to negotiate the funding agreement between developer and government. Then private finance and detailed project planning and permitting must be concluded before construction can commence. In Australia, funded projects have required an average of five to ten years to produce meaningful outcomes of any sort.

Figure 6.2 Australian governments capital grant expenditure for emissions abatement projects[33]



Source: Grattan Institute (Daley et al., 2011a)

There may be genuine factors that invalidate bid assumptions or otherwise lead to projects being withdrawn. Evolving understanding of the technology, project requirements or regulatory changes can make the bid unviable.[34] Commodity

[31] For instance, the original design of the Solar Flagships program aimed to deliver 1000 megawatts of capacity with $1.5 billion in funding, with the private sector to invest $2 for every $1 of government support. However, industry participants indicated that private funds cannot earn an adequate return on these terms. In addition, many developers interviewed by Grattan Institute indicated that unclear criteria made it very difficult to develop bids and judge future investment decisions. Daley*, et al.* (2011b)

[32] Daley*, et al.* (2011a)

[33] LETDF: Low Emissions Technology Development Fund (Commonwealth), GGAP: Greenhouse-gas Abatement Program (NSW) & ESF: Energy Savings Fund (NSW)

[34] Daley*, et al.* (2011a). For example, the HRL lower emissions coal-fired power plant became unviable when the 2008 Carbon Pollution Reduction Scheme

prices can change significantly over the long project lead-time, pushing up the cost of construction. Difficulties in securing a power purchase agreement can make it very hard to obtain finance.

Ideally this uncertainty should be built into the price that companies bid. But competitive pressure pushes developers to strip it out. Poor experience with tender schemes is not limited to Australia. In the United States, for example, aggressive bidding has been identified as a threat to states achieving their renewable energy targets. A 2006 survey of 21 utilities found an average failure rate of 20 to 30 per cent for large tenders conducted over multiple years. More recently, California's three investor-owned utilities reported project failure rates of 30 to 50 per cent.[35]

In India, the results of a national solar auction held in December 2011, stretch the bounds of credibility. The auction awarded contracts for 350 megawatts of new capacity at rates as low at 7.5 rupees per kilowatt-hour. But the minimum cost to build and operate a new solar PV plant is thought to be around 10 rupees per kilowatt-hour. Proponents are effectively betting on the future providing better technology, lower equipment costs and/or cheaper finance being available. [36]

White Paper indicated that plants that had not been committed to before mid-2007 would not be eligible for free carbon emission permits.

[35] Kreycik*, et al.* (2011b). These were tenders run by utilities for electricity generation, not government grants. However, they highlight the same issue with tender programs.

[36] The Economist (2012) Some analysts consider that many solar PV projects will be delivered, because the technology price has fallen so much, but consider concentrating solar power projects to be more doubtful. Pers comm Asian Development Bank 2012

On their own, low-cost loans are not likely to produce large-scale deployment

Low-cost 'soft' government loans may help to facilitate additional private sector investment in low-emissions technologies. In Germany, for instance, loans offered by the state-owned KfW Bank (~1.5% below market rate) are thought to lower project costs, directly, through lower interest repayments, and by increasing the tenor of the loan.[37]

In Australia, the Government's recent Clean Energy Finance Corporation Expert Review highlighted a number of areas where low-cost government loans or investment may improve clean energy project financing.[38] Westpac Bank suggested the following examples in its submission to the Review:[39]

- projects with significant technology risks
- projects that are not viable given the current low cost of electricity, including RET funding
- projects that are too small for merchant banks but too complicated for commercial banks. These include five to 10 megawatt commercial rooftop solar PV installations.

Yet for two reasons, such loans are unlikely to produce large-scale deployment without some other form of policy support. First, government debt programs can support only a narrow range of projects. They focus on projects that are sufficiently developed to

[37] de Jaeger and Rathmann (2008)

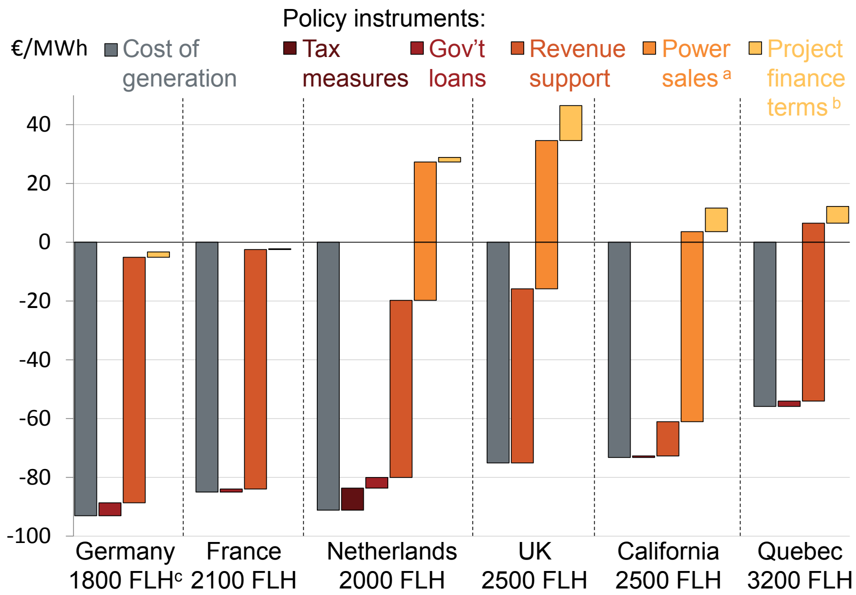
[38] Clean Energy Finance Corporation (2012)

[39] Westpac Institutional Bank (2011)

provide a return, but not so advanced that they can obtain finance on commercial terms. Even if non-commercial projects are cross-subsidised by commercial investments, this approach can only develop technologies that are already close to full commercial stage or have access to some other form of support.

Second, project finance modelling suggests that the overall impact of low-cost loans is not great.[40] A 2008 study commissioned by the IEA simulated support policies in six jurisdictions, together with local finance and technology costs and typical resource availability.[41] The results, shown in Figure 6.3, suggest that revenue supports[42] (light brown) have been far more significant than government loans (dark red) in meeting the cost of developing and operating on-shore wind farms. Both tax measures and loans made very small contributions towards the levelised cost of electricity — less than €5 per megawatt-hour in all examples. The same study showed that investment incentives had a slightly larger impact for solar PV projects, because the cost of finance was more important. But these also relied on revenue support.[43]

Figure 6.3 Contribution of government policies to the levelised cost of 20 MW on-shore wind power projects in 2006, based on the average wind resource in each country



Source: de Jaeger and Rathmann (2008)

Notes: *(a) Revenue from electricity sales is modelled only in countries whose support policies permit projects to seek revenue from the market (not feed-in schemes) (b) The authors modelled the impact of 'better' financing terms as a 9% Return on Equity, a Debt Service Coverage Ratio of 1.3 and debt term of 15-20 years. (c) FLH = Full-Load Hours, the number of hours during which wind turbines operate at full capacity per year. Each country's FLH depends on its average wind resource. In several cases above the average FLH is too low for projects to break even – a better quality site would be needed for developers to proceed.*

[40] The effect of low-cost 'soft' loans can be ambiguous, because so often they have been implemented alongside other technology support schemes. Modelling is one way to disentangle the effects of multiple policies.
[41] de Jaeger and Rathmann (2008)
[42] Feed-in or TGC revenue support, or production tax incentives. In Figure 6.3 'Tax measures' refers to fiscal adjustments such as tax deductions on capital investment, or accelerated depreciation
[43] An example illustrates this. In Germany the *100,000 roofs* solar PV program offered a low-cost loan at 1.9% pa over 20 years. Initially uptake was modest, but installations accelerated after 2000. This coincided with a massive increase in the German solar PV feed-in tariff from 8.2 to 50.62 €c/kWh — it is hard to believe that the loan program did the heavy lifting. Bechberger and Reiche (2004)

In Brazil the state-owned lender BNDES appears to have played a significant role in stimulating wind power development through low-cost loans. But this is only because it offers interest rates in the order of 6 per cent lower than commercial finance and the bank has committed a very large amount of capital to wind power (about $10 billion since 2000).[44] This approach is very different to a loan program that requires a near-commercial rate of return.

It is unclear whether capital support schemes are efficient for government or produce an incentive to reduce costs over time

The private sector uses higher discount rates than do governments, meaning they place a lower value on costs and benefits that will (or might) occur in the future. Upfront capital payments therefore have an advantage to governments over revenue support schemes.[45] That benefit, however, must be set against the difficulties governments face in selecting individual projects for support. This casts doubt on whether capital support schemes are cost-effective for government.

A grant, soft-loan or equity investment does not in itself provide any incentive to developers to reduce their costs in future. If companies succeed at reducing their costs, they may simply get a smaller grant for the next project. On the other hand, a series of well-executed tenders, or auctions, could provide the necessary certainty and competition to induce the private sector to invest in the skills, systems and experience needed to reduce costs.

Low-cost loan programs may struggle to both produce a commercial return and avoid crowding out private investment

Government may require a low-cost loan program to produce a minimum rate of return. This limits the net budget impact and permits the program to make a mix of commercial and non-commercial investments. However, it is not clear that such an approach can produce returns good enough to meaningfully support non-commercial projects yet at the same time avoid crowding private financiers out of viable projects.[46]

6.5.3 Portfolio of options

Investment incentives can produce technology diversity, but only if government chooses a range of technologies to support. This substantially increases overall complexity and the scope for 'picking winners' mistakes. For soft loans, requiring a commercial rate of return on investment means that technology diversity is less likely.

The total policy cost is easily capped, being on budget and under government control.

6.5.4 Feasibility

A system of grants or loans can work with an emissions-trading scheme. Yet as for all instruments discussed in this chapter, support will alter the carbon market and probably depress the

[44] US PREF (2012)
[45] Garnaut (2008)

[46] Several investors consider this to be a risk. Westpac Bank has recommended that the CEFC should implement an additionality (not crowding out the private sector) investment test, as do Low Carbon Australia and the Clean Development Mechanism Executive Board. Westpac Institutional Bank (2011)

carbon price. Interactions should be limited, however, while technologies are immature and expensive.

6.5.5 Predictability and Flexibility

Providing support through upfront payments is clean: there is a single transaction and once it is completed there is no policy risk for the company. But policy risk is a serious issue for the industry as a whole. Ongoing grant programs often lack transparent rules about how long they will endure and how much support will be offered from year to year. Funding can easily be appropriated for a different use. For example, in February 2011 the Commonwealth Government planned to cut its Solar Flagships program in order to help fund an assistance package in response to floods in Eastern Australia.[47]

6.5.6 Design options to reduce weaknesses

A project bond to provide a strong incentive to deliver projects on time and on budget

To help reduce the risk of unrealistic bidding in tender and reverse auction schemes, government can require the successful bidder to post a project bond against the risk of late or non-delivery. This must be an amount large enough to create a strong incentive for the developer to deliver the project as bid.

The bond could be a fixed sum or a percentage of the project's estimated capital value. Alternatively, the bond could be designed to increase as the value of bids decreases. This approach progressively raises the risk of aggressive bidding. It requires government to publish a minimum bond amount, a "reserve price" range that corresponds to the minimum and the rate of increase that will be applied to bids below the reserve price. The approach has been implemented in India with some success. However, the relationship between the project and bond size needs careful consideration.

A drawback of this approach is that it requires additional capital funds from developers that already may be struggling to acquire project finance. The effect may be to reduce the number of participants that can credibly bid in a tender or reverse auction process. Relative to the risk of unrealistic bidding, this is the lesser evil.

Grants paid on performance, rather than promise

Instead of paying at proposal stage, government can spread payments over a set of project milestones or gateways. These could be a commitment to construction, completion of civil engineering works, transmission connection or a number of months of commercial operation. Taking this approach — in effect a series of prizes — reduces government exposure to project delivery risk. On the other hand, developers are more exposed to policy risk and government may still need to select individual projects for support.

Another approach is to offer a major bonus to the first developer to clear a pre-specified performance hurdle. A race would give developers an incentive to deliver projects rapidly and at low cost. Yet if there is a race, developers face a new risk of not winning a

[47] The cuts did not proceed because of opposition by the Australian Greens Party. Climate Spectator (2011).

contract, or winning insufficient government support, and few may choose to compete.

Government can use the private sector to improve project selection

For grant tender or reverse auction schemes, a simple way to improve government project selection is to require developers to have an agreement for private finance ahead of bidding for a grant. The financial backing can be conditional on winning the grant. This approach significantly increases the onus on the project proponent to develop a realistic bid, as it will be carefully scrutinised by their financiers. It also means that proponents must commit much more time and resources without any certainty of winning government support. To make this investment worthwhile for developers, government would probably need to commit to a series of auctions over time, so that any bid would have several opportunities to win funding.

For debt or equity investment, government can use private sector capability by partnering with private investors.[48] One approach is to co-invest in projects on similar terms to a lead investor. This adds a check to the due diligence, financial structuring and contractual arrangements negotiated by government. An alternative is to invest through a third party-managed fund. If such a fund achieved a commercial rate of return, it would enable government to focus on investing in higher-risk projects on sub-commercial terms.

[48] Recommended by the Investor Group on Climate Change in its submission to the CEFC Expert Review. IGCC (2011)

6.6 Feed-in revenue support schemes (feed-in tariffs, feed-in premiums)

Table 6.2 Summary of feed-in strengths and weaknesses

		Strengths	Weaknesses	Design options to improve weaknesses
Efficiency & effectiveness		Overall allocation of risks supports technology development. Addresses carbon market, technology spillover and electricity market risk Feed-in instruments have produced very large-scale deployment Clear incentive to reduce technology costs Often cost-effective	Risks of project overpayment, scheme oversubscription and a boom-bust market No mechanism to ensure that government funds do not crowd out private investment	Short-term risk: Reverse auction tariffs to reveal developer cost expectations and introduce competitive pressure Long-term risk: two-way contract for difference. Excess profits are paid to government / consumers if the market price exceeds an agreed strike price
Portfolio of options	*General*	Largely successful at deploying a range of technologies	Government must estimate multiple technology-specific tariffs to produce options	
	Feed-in Tariffs		Developers have no incentive to meet variable electricity demand, and government bears electricity market risk	
	Feed-in Premiums	Developers have an incentive to produce projects that can meet variable electricity demand, because they bear electricity market risk	Developers' exposure to electricity market risk increases the cost of finance and favours large incumbents	Revenue floor to limit downside risk to developers and separate revenue ceiling to return excess profit to government or consumers
Feasibility		Can work with an emissions-trading scheme	Will depress the carbon price	
Predictability & flexibility		Government does not select projects ahead of delivery	High levels of budgetary and political risk for government mean that policy changes are more likely	Rules to automatically reduce, or degress, the rate of support. Degression can be staged over time or triggered when installed capacity reaches pre-determined thresholds. These have had mixed results

6.6.1 Overall assessment of feed-in schemes

Feed-in, or direct revenue, support shifts a large proportion of project risk to government (or to electricity consumers). In particular, carbon market, technology spillover risks and electricity market risk are transferred to government, but project selection and delivery risks remain with developers. Feed-in schemes have been very successful at deploying new capacity for a range of technologies. Large amounts of investment make learning-by-doing cost reductions very likely.

However, there is a genuine danger of government being exposed to too much risk, because total cost can easily spiral out of control. There are some options to at least partly manage this.

6.6.2 Efficiency and effectiveness

Overall allocation of risks supports technology development

Feed-in schemes are able to compensate for technology spillover risk and carbon policy risk, provided the payment is high enough. This is because support is guaranteed and ongoing payments provide a better match for the enduring carbon policy risk. The ‘first-in-first-served’ approach to awarding contracts means that government does not bear project selection or delivery risks.

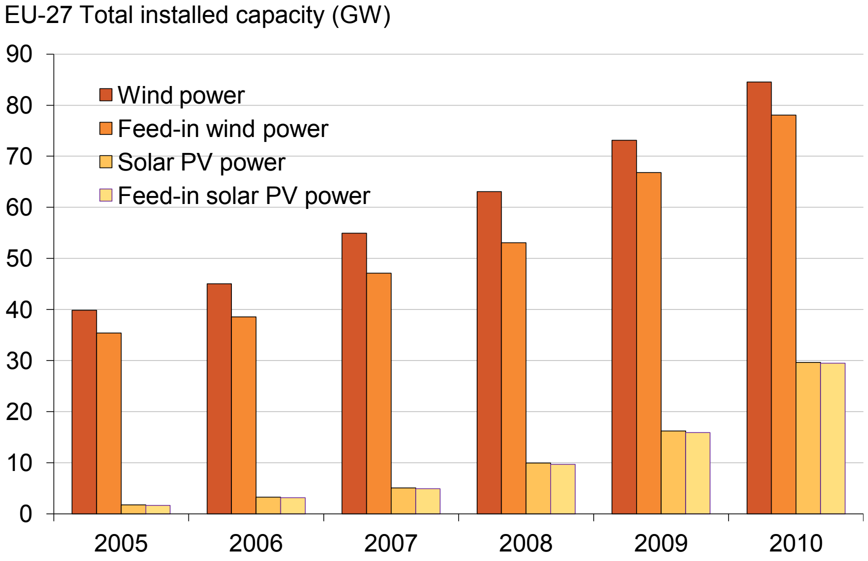
For developers, the combination of simplicity and long-term certainty is very attractive. According to investor surveys and project finance modelling, what matters most to investors are the duration of policy support, revenue certainty and the perceived level of risk.[49] However, government bears significant risks of project overpayment and total policy cost, as is discussed below.

Feed-in instruments have produced very large-scale deployment

With developer risk so low, feed-in policies have produced the strongest conditions for major investment in new capacity relative to all other instruments (Figure 6.4). Analyses by the European Commission and the IEA broadly support the conclusion that Feed-in Tariffs (FiTs) have produced more capacity than other schemes over the period 2001 to 2009.[50]

[49] Luthi and Prassler (2011);Rathmann, *et al.* (2011);Varadarajan, *et al.* (2011)
[50] IEA (2011); Commission of the European Communities (2008). Recently TGC schemes appear to be catching up in wind power, but not solar PV. This may reflect that wind power technology is now more mature than it was in the early 2000s. IEA (2011).

Figure 6.4 Renewable energy deployment supported primarily by feed-in instruments, EU-27 countries



Source: Ragwitz et al. (2012)

A clear incentive to reduce technology costs

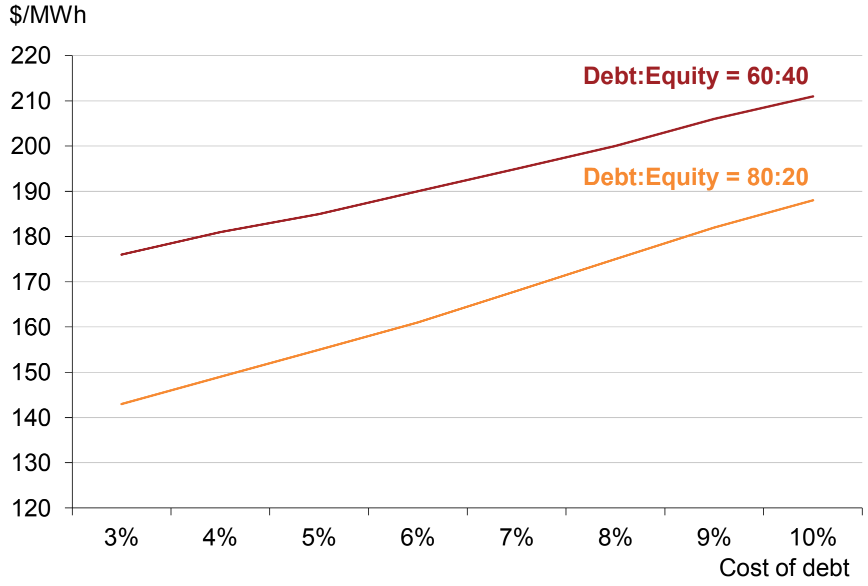
Feed-in schemes do not produce competition between developers on price. But there is an incentive to reduce cost, because the level of government support is guaranteed and any innovations will increase profit. A tariff that is designed to fall over time can also put pressure on developers to reduce their costs. Feed-in schemes may also promote competition between equipment and construction suppliers.[51] Many analysts consider fixed revenue to be the very attractive instrument for developers, and highly likely to stimulate innovation.[52]

Feed-in revenue support schemes have often proved cost-effective

While feed-in schemes do not produce developer competition, the long-term certainty they offer can translate into lower costs. In Germany the security of a 20-year feed-in tariff allows for very low-cost financing. Bloomberg recently reported a ratio of debt-to-equity in the range of 80:20 for German solar PV developments.[53] Projects in the US, by contrast, achieve ratios of around 60:40 (with the production tax credit) or 70:30 (loan guarantee).[54] The difference makes for a substantial saving in the electricity produced (Figure 6.5).[55]

[51] Butler and Neuhoff (2008)
[52] Menanteau, *et al.* (2003);de Jaeger and Rathmann (2008);del Rio Gonzalez (2011);Haas, *et al.* (2011);Batlle, *et al.* (2012)
[53] World Economic Forum / Bloomberg New Energy Finance (2011), pp32-33
[54] *Ibid*
[55] Energy projects are capital intensive and the cost of equity finance is typically 15 to 20 per cent per annum, compared with 6 to 8 per cent for debt.

Figure 6.5 The cost of solar PV power[56] varies with the ratio of debt to equity



Source: pers comm Clinton Foundation (2012), using data from Bloomberg New Energy Finance

Similarly, increasing the contract length for a US solar PV project from 10 to 20 years significantly impacts on the overall cost. A longer contract, and consequently a longer debt term can reduce the power price from $270 per megawatt-hour to $170 per megawatt-hour.[57]

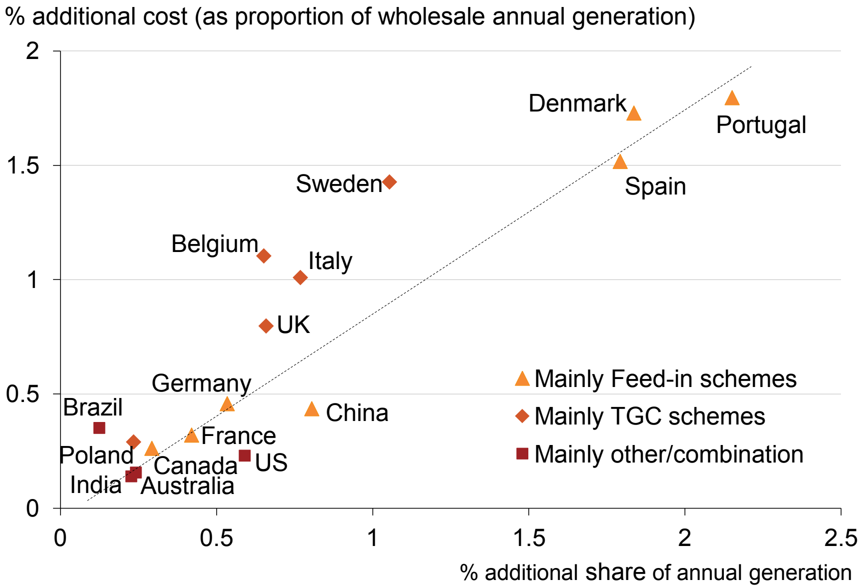
Feed-in schemes also perform well when compared with alternative policies. Figure 6.6 shows the additional cost produced by on-shore wind power generation in a range of countries.[58] The data suggest a more or less straight line along which most have traded-off a higher electricity price against additional megawatt-hours of wind power.

[56] Assumptions: 10MW crystalline PV array, construction breaks ground in 2013. Capacity factor 18 per cent, global horizontal irradiance 1,800 kWh/m^2, capex $2.18/W, opex $0.015/W, operating life 21 years

[57] Assumptions: 1 MW dual-axis tracking solar PV plant at Colorado Springs. 60% project debt and 30% Federal Investment Tax Credit. Speer (2012)

[58] Wind power is a relatively mature technology and the underlying equipment cost does not vary greatly. Given this, cost variation must result from scheme or country differences.

Figure 6.6 Cost-effectiveness of technology support schemes for on-shore wind power, 2009[59]



Source: IEA (2011)

But on average, feed-in schemes have produced additional wind power more efficiently than indirect revenue support, or Tradeable Green Certificate (TGC) schemes. The primary reason is that developers enjoy more certainty under the feed-in approach. It is thought that non-economic barriers, like land-use planning and transmission connection challenges, pushed up TGC scheme costs in the UK, Italy and Belgium. This tempers the conclusion that TGCs are more expensive. However, there is no evidence that TGC schemes are cheaper.[60] Section 6.7 explores the TGC issue in detail.

There are risks of overpayment, oversubscription and a boom-bust market

In practice feed-in schemes tend to overpay developers. Governments must estimate the appropriate level of revenue support, because the optimal price is unknown. They tend to over-compensate developers rather than risk a scheme that offers too little and produces no projects. Governments are particularly vulnerable to the technology cost falling so fast they cannot reduce support in an orderly way.[61] Cumulatively, this can have a major impact — a generous tariff tends to quickly produce a surge in activity. This is undesirable. Experience shows that spiralling costs often provoke governments into clamping down on the program. In turn this can undermine investor confidence and send markets rapidly from boom to bust.

The Spanish experience with government support for solar PV power is a prime example of how this can play out. In the late

[59] This indicator does not account for the merit-order effect, where increases in penetration of renewable generation can lower the average wholesale price for electricity. This occurs because most of the cost of renewable generation is in construction. With zero or very low fuel cost, renewable generators can bid very low prices for a marginal unit of power. This lowers the average price of electricity.

[60] Differences in resource quality between countries can also account for significant variation in the average cost of renewable power generation. Yet IEA data indicate the same trend once these differences are taken into account. IEA (2011)

[61] The case in point: the average solar PV module cost fell by about 20% over 2009. This left many countries committed to now overly generous feed-in rates. Ibid.

2000s the Spanish government's tariff was already generous. At between 248 and 475 euros per megawatt-hour (depending on the system size) it was based on rates set in north European countries, but the sunshine is better in the south, and therefore the economics of solar power is too.[62] But in 2007-08 Spain's policy became exceedingly generous, as it was ill-equipped to respond to the plummeting price of solar PV technology.

In 2007 the Spanish government set a nominal target of 371 megawatts of solar PV, to be achieved by 2010. Most of the quota, 315 megawatts, was installed in the first six months. The government then moved to limit its liability — the scheme was not capped — by announcing that no projects would receive the tariff beyond September 2008.

The deadline spurred the booming market into a headlong rush. A total of 506 megawatts was installed by the end of 2007. In 2008, 2,661 megawatts of new capacity went in. This quintupled Spain's capacity in just one year and made it temporarily the largest market for solar PV in the world. Subsequently, the Spanish government revised the scheme to better track technology costs and control total policy cost.[63] By comparison, Australia's total installed solar PV capacity over 1992-2010 was about 600 megawatts.[64]

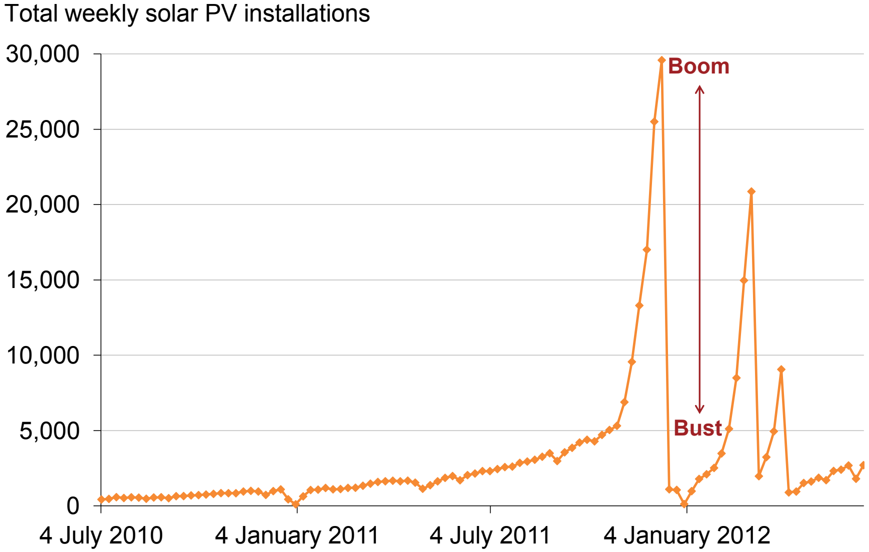
[62] EREF (2009);BMU (2011a)
[63] Despite this, major policy changes were introduced in 2010, cutting solar PV subsidies by 45%. Further changes were announced in early 2012, this time to temporarily suspend the scheme from 2013. However, these most recent revisions are driven by major debt and capacity issues in Spain's electricity market, rather than defects in the feed-in scheme. For more detail see Couture (2012).
[64] Australian PV Association (2011)

The boom-bust experience is not limited to Spain. In the UK, a series of legal challenges to Government attempts to cut back on solar PV support — and three subsequent appeals — have set the solar PV market seesawing up and down (Figure 6.7). In the Czech Republic feed-in supported solar PV installations overshot the Government's target 2020 target (1,700 megawatts) a decade ahead of schedule. In 2010, its market boom had installed 1,900 megawatts of new capacity, creating a liability for government equal to approximately 18 per cent of the entire Czech wholesale electricity market.[65]

Ad hoc changes have been imposed on schemes in most Australian States.[66] In 2011 the Victorian Government reduced its solar power support rate by 58 per cent, from 60 to 25 cents per kilowatt-hour. The New South Wales Government cut its feed-in rate from 60 to 20 cents per kilowatt-hour, but was prevented by State Parliament from applying the changes retrospectively. The Queensland Government has very recently introduced cutbacks (from 44 to 8 cents per kilowatt-hour), and it may succeed in applying them to existing solar PV installations. Solar PV support has also been cut in WA, SA and the ACT.

[65] IEA (2011) p20, p128
[66] These have focussed on support for small-scale PV, not large installations.

Figure 6.7 Boom and bust in UK solar PV installations

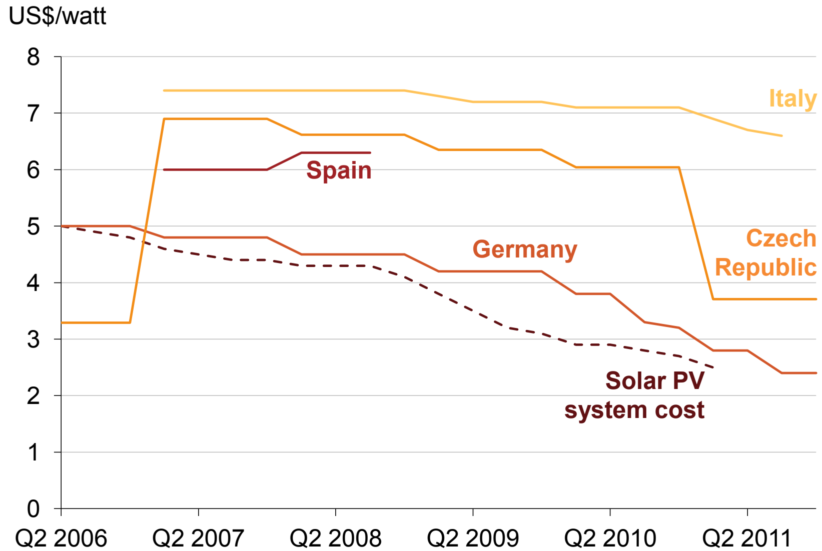


Source: Department of Energy & Climate Change (2012)

Good scheme governance can mitigate these risks to some extent. Governments have controlled costs by capping the total capacity available at a given rate, or by introducing a series of tariff reductions (known as 'degression'). These can be staged over time or triggered when installed capacity reaches pre-determined thresholds. Often these are used in conjunction with regular reviews of the feed-in rate.

The challenge is to reduce support by the right amount, at the right time, in an orderly and predictable way. As Figure 6.8 suggests, some countries have managed this better than others. Germany arguably has had the most success with feed-in tariff policy, but even there recent, drastic cuts to feed-in rates (ranging from about 20 to 29 per cent) have led to public protests and tension between the government executive and the Bunderstrat, the German Federal Council.[67]

Figure 6.8 Solar PV system costs and feed-in tariff rates



Source: (Fulton and Mellquist, 2011)

[67] Olson (2012)

There is no mechanism to ensure that feed-in support is additional to private investment

While technologies are immature and their costs high relative to the wholesale electricity price, there is no risk that government support will replace private investment that would have happened anyway. However, while automatic mechanisms can reduce the rate of support over time, reviews are the only means to estimate whether support remains additional to rather than a substitution for private investment. Government intervention is needed to cease support for a specific technology.

6.6.3 Portfolio of options

Multiple, technology-specific rates are needed produce options

A single feed-in tariff will make some technologies commercially viable. But technology diversity will emerge only if the cap is high enough to progressively deploy higher-cost technologies once lower cost alternatives are effectively exhausted. In practice, feed-in tariff schemes either accept single technology deployment or employ a system of technology-specific rates.

The latter will deploy multiple technologies, provided that the level of support for each is sufficient. However, it greatly expands the number of rates that government must estimate, making the scheme considerably more complex. Germany, for instance, offers support in about 70 distinct categories, ranging from small-scale biogas plants to large-scale offshore wind farms.[68] The multiplicity increases the scope for mistakes, overpayment and the boom-bust cycle.

Feed-in premiums: developers have an incentive to produce projects that can meet variable electricity demand, because they bear electricity market risk

Unlike a fixed-rate feed-in tariff, a feed-in premium is an amount paid on top of the wholesale price of electricity. Therefore, total revenue varies with changes in the electricity price. This provides the private sector with an incentive to develop projects that have more capacity to despatch power according to demand.[69] Despatchable power is inherently more valuable in an electricity market with variable demand, because it can be sold when the market needs it most.

However, a feed-in premium shifts electricity market risk to developers, making higher costs of finance more likely. Project finance modelling suggests that relative to a feed-in tariff, a feed-in premium can increase the cost of finance from 2 to 6 per cent, depending on the project.[70]

While it is broadly appropriate for developers to take electricity market risk, this may prove a burden for new entrants. They tend to be smaller companies, for whom the risk burden is proportionally greater. Secondly, they have little influence over the wholesale electricity market prices, unlike large generator-retailers, who own or operate coal or gas-fired plants and are better able to manage this risk.

[68] BMU (2011b). This does not include pre-determined annual degression rates, which goes forward 10 years in some categories.

[69] Couture and Gagnon (2010);Batlle, *et al.* (2012);Klessmann (2012)

[70] Rathmann, *et al.* (2011);Varadarajan, *et al.* (2011)

Observations in the Spanish market support this. Batlle et al. (2012) notes that many smaller investors left the market when Spain shifted from a tariff to a premium in 2004.

6.6.4 Feasibility

A feed-in scheme can work with an emissions-trading scheme. But as with investment incentives, support will alter the carbon market and probably will depress the carbon price.

6.6.5 Predictability and Flexibility

Managing a scheme with objective criteria improves predictability, but does not guarantee it

As the preceding discussion outlined, there is a number of options to help to contain total policy cost and maintain scheme transparency. But countries have had mixed success with these and they have not fully avoided governments making additional, unpredicted policy changes. Managing a scheme with objective criteria does not guarantee that decisions will always be predictable and transparent.

Direct revenue support can be funded by a levy on electricity consumers. As a result, future governments may be less likely to interfere with a policy that has no direct impact on the budget bottom line. However, this may not hold if consumers become concerned about electricity prices. In this case political pressure could work against stability in the program.

6.6.6 Design options to improve weaknesses

Reverse auction to select projects and control total policy cost

Reverse auctions can be used to award feed-in contracts. This approach avoids government having to estimate the optimum feed-in rate. Bidding reveals the efficient level of revenue support. A series of auctions can push project costs down over time and government retains control over the total policy cost. Auctions have been implemented in Britain, Brazil, Chile, California, China and India, among other jurisdictions. They have recently been developed in South Africa and the Australian Capital Territory. Saudi Arabia has announced its intention to auction five gigawatts of solar power capacity beginning in 2013, as the first step to reaching a stated goal of 41 gigawatts of solar capacity by 2032.[71]

The evidence is that auctions do put significant downward pressure on the cost of low-emission energy technology projects. Wind power auctions in Brazil in 2010 produced an average price that, while still credible, was 42 per cent lower than projects supported by the Brazilian Government between 2002 and 2005.[72] Results from August and December 2011 have pushed the price down further still.[73] Similarly, from auction round one to round two, the South African program reduced the bids for solar PV projects by about 40 per cent, from $US275 to $US165 per

[71] Solar Server (2012)
[72] Kreycik, *et al.* (2011a)
[73] US PREF (2012)

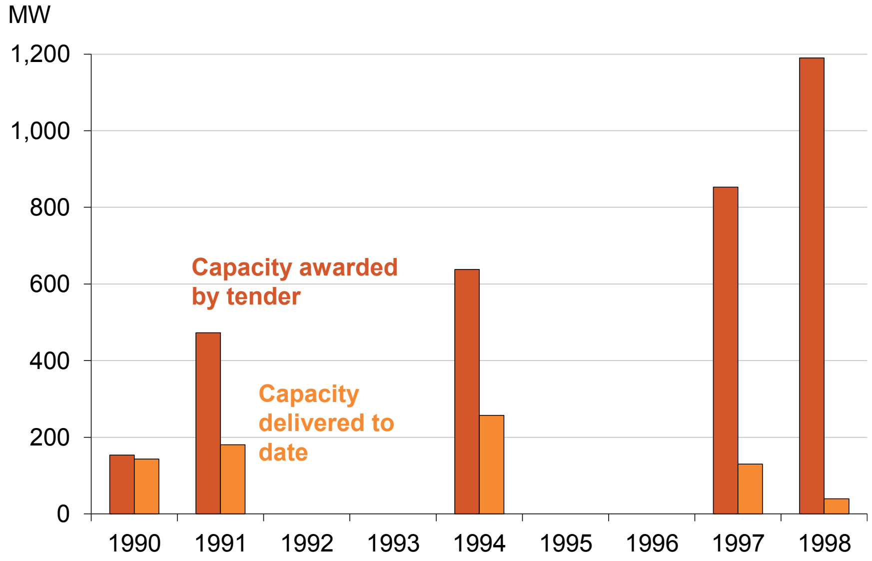
megawatt-hour. In the same period wind power projects fell from US$114 to $89 per megawatt-hour.[74]

Yet these schemes have a mixed record. Like grant tender schemes, auctions carry a significant risk that developers will bid extremely low in order to win the auction, but then fail to deliver the project. This problem, so-called 'contract failure', has arisen in schemes around the world, such as China, California and the UK,[75] and may prove to be a challenge for wind power in Brazil and concentrating solar power in India.[76] In Britain the Non-Fossil Fuel Obligation (NFFO) scheme produced far less capacity than had been contracted for (Figure 6.9).

As outlined in Chapter 4, our proposal addresses this weakness in several ways. These include paying only for electricity delivered, so that government is not exposed to project selection and completion risks, requiring proponents to negotiate project finance before bidding, and requiring proponents to post a bond, a strong financial incentive to deliver projects on time. The UK scheme lacked financial penalties, and was also inhibited by land-use planning issues.[77]

[74] pers comm Clinton Foundation (2012); Parkinson (2012); Deparment of Energy - Republic of South Africa (2012)
[75] Kreycik*, et al.* (2011a); Haas*, et al.* (2011)
[76] Brazil: US PREF (2012). India has seen aggressive bidding for both solar PV and concentrating solar power projects. But solar PV developers may have found a lucky safe landing in the very rapid fall in global PV prices. The CSP projects have not yet been constructed, but it is thought that they are more likely to face problems. Pers comm Asian Development Bank (2012).
[77] Mitchell and Connor (2004);Haas*, et al.* (2011)

Figure 6.9 England and Wales Non-Fossil Fuel Obligation: new capacity projected and delivered



Source: Haas et al. (2011)

Two-way contract for difference to recoup support

There is a longer-term risk of revenue support becoming a source of windfall profits if over time electricity market prices rise — because of a rising carbon price, for example — and make support unnecessary. To limit this risk, a revenue support contract may be structured as a two-way 'Contract for Difference' agreement. In this approach, government agrees to subsidise developer revenue up to an agreed strike price. If in future profit is earned above that price, the developer must pay all additional profits back to government or consumers. The recent UK Government white paper on electricity market reform makes a proposal along these lines.[78]

Feed-in premium: floor and ceiling prices to limit developer and government risk

Exposing developers to electricity market price signals is desirable, but it also means that both developers and government bear additional market risks. Developers risk that wholesale prices will drop below the minimum level needed to make their project viable, even with the premium. Governments risk wasting funds when electricity market price fluctuations are high and the full level of support is unnecessary.

A possible response is to modify the premium so as to offer a floor and a ceiling on developer revenue. In this case the floor acts somewhat like a feed-in tariff, a guaranteed level of support for the developer that reduces risk. Changes in the wholesale electricity price may push the level of support above the floor price but up only as far as the revenue ceiling, beyond which the developer pays back profits as per the two-way agreement described above. In effect, the ceiling compensates government for insuring developers against the risk of prices falling too low.

[78] Department of Energy & Climate Change (2011b)

6.7 Tradable Green Certificate revenue support schemes

Table 6.4: Summary of tradable green certificate scheme strengths and weaknesses

	Strengths	Weaknesses	Design options to improve weaknesses
Efficiency & effectiveness	Can deploy new capacity at large scale Limited or no risk of government funds crowding out private investment Can drive learning-by-doing innovation	Replaces carbon market risk with separate renewable credit market risk Substantial developer risk can increase project costs and the overall cost of support	Long-term contracts for certificate supply may increase investor confidence and reduce the cost of project finance
Portfolio of options		Complex modifications are needed to produce multiple technology options beyond lowest cost today	
Feasibility		Likely to overlap with the emissions-trading scheme, and depress the carbon price. Other climate change policies may depress the certificate price	
Predictability & flexibility	Overall capacity target is typically legislated and difficult to revise downwards or remove Off-budget funding increases likelihood of scheme persistence	Governments have a record of frequently changing scheme rules Governments have a chequered history enforcing scheme compliance An arbitrary target and end-date create uncertainty about the scheme in the longer-term	Predictable reviews and timely announcement of changes reduce regulatory uncertainty Absolute target (MW or MWh) reduces uncertainty

6.7.1 Overall assessment

Tradeable Green Certificate (TGC) schemes do not match well with the objective of reducing technology costs and risks. While TGC schemes have a track record of producing significant new deployment, in effect they replicate the conditions of an emissions-trading scheme but with narrower scope. Developers bear most risks, including technology and market-related risks. The market mechanism naturally focuses on lowest-cost deployment and does not easily adapt to supporting the development of a portfolio of options. To achieve this aim government must impose complex constraints on the market. These interventions are unlikely to produce the best results.

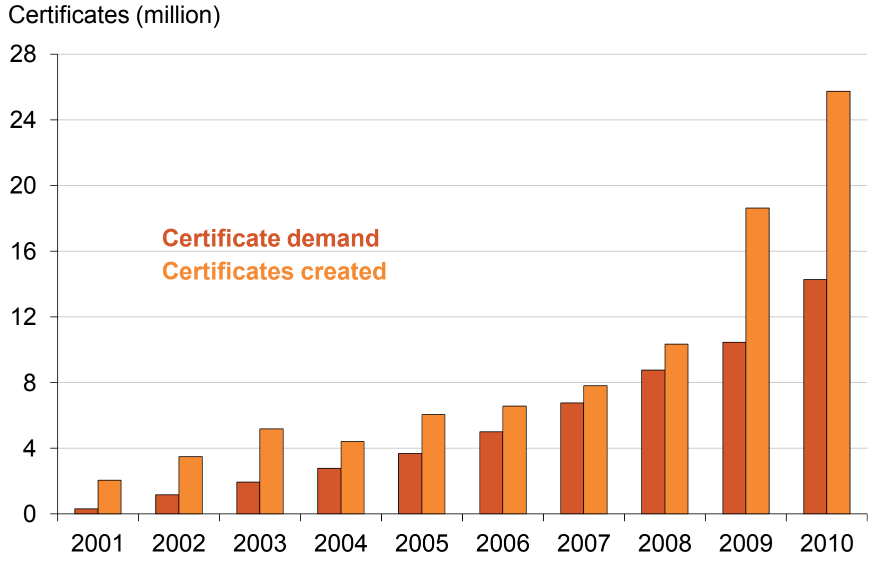
Moreover, governments around the world have at best a mixed record implementing TGC policies. Rule changes have been common and regulators have proved at times reluctant to enforce compliance. As a result interim deployment targets have gone unmet. Some design options can address these weaknesses, but their impact is limited and they may create new complications.

6.7.2 Efficiency and effectiveness

TGC schemes can deploy new generation at large scale

Indirect revenue schemes have shown that they can deploy significant generation capacity. In Australia, the Renewable Energy Target (RET) has actually produced the targeted capacity before it was required to meet its market obligations (Figure 6.10).

Figure 6.10 Australian Renewable Energy Certificate demand and supply 2001-10



Source: Grattan Institute (Daley et al., 2011a)

In the United States more than 9,000 MW of new renewable energy was installed in states with a Renewable Portfolio Standard in the decade to 2008. These schemes have been a major influence on wind energy deployment: one analysis concluded that, discounting all other policies, adopting a TGC scheme has increased US states' wind power capacity by an average of 498 megawatts per year, compared to states without a legislated RPS.[79]

TGC schemes generally do not crowd out private investment, but they do shift the relative benefits of different investments.

Being a market mechanism, a TGC scheme provides support through the private sector. So by definition the government avoids crowding-out private investment in technologies that are included in the scheme.[80] The approach has proved especially popular in deregulated markets because it is seen as compatible with competition.[81] In the US every state with a competitive retail electricity sector also has a Renewable Portfolio Standard.[82]

There is a risk that TGC-supported deployment will crowd-out technologies that are viable but not included in the program. This could occur for small-scale technologies, but is unlikely in large-scale generation. It is also possible that a TGC scheme will subsidise deployment that would have occurred in any case. Yet this will be visible in the certificate market — it will depress the certificate price — and government can take steps to manage the impact.

The risk burden is similar to that of an emissions-trading scheme

Indirect revenue support helps to address carbon policy risk by guaranteeing demand for low- or zero-emissions electricity. Yet developers still face several risks that they cannot easily manage.

First, they bear technology and project delivery risk. The certificate market effectively removes carbon and electricity market risks, but it replaces them with new certificate market risks. For instance, developers may not be certain of the price or volume of demand for their product over the longer-term.[83] TGC schemes also suffer the same type of regulatory uncertainty as emissions-trading schemes. Developers are often reluctant to invest in higher-risk projects on the basis of the certificate price being higher in the future, because it is uncertain whether government will maintain the target and enforce the necessary penalty charge.

Governments and consumers bear very few project-related risks under a TGC scheme.

Substantial developer risk can increase the cost of support

Several analyses suggest that government support costs can be higher in a TGC scheme than comparable deployment under a feed-in scheme.[84] Project developers must pay for higher cost finance and and/or larger margins for investors. This increases overall project cost.[85] Measures to increase technology diversity,

[79] Adelaja and Hailu (2008)
[80] This does not hold for technologies that are excluded from the scheme — these may be crowded out. The narrower the scheme, the more likely this becomes.
[81] Finon and Perez (2007)
[82] Rickerson and Grace (2007); Caperton (2012)

[83] This can be mitigated by requiring participants enter into long-term contracts, but this has other drawbacks. See discussion below.
[84] Faber, *et al.* (2000);Johnston, *et al.* (2008);Haas, *et al.* (2011);IEA (2011)
[85] de Jaeger, *et al.* (2011)

such as multipliers that boost the value of electricity from a specific technology may make the situation worse by increasing regulatory uncertainty and making it harder for investors to predict future certificate prices.[86]

The situation may limit competition by favouring large, vertically-integrated utilities that also own the distribution and retail business that must purchase certificates. By contrast, small developers and new entrants can find it difficult to obtain finance.[87]

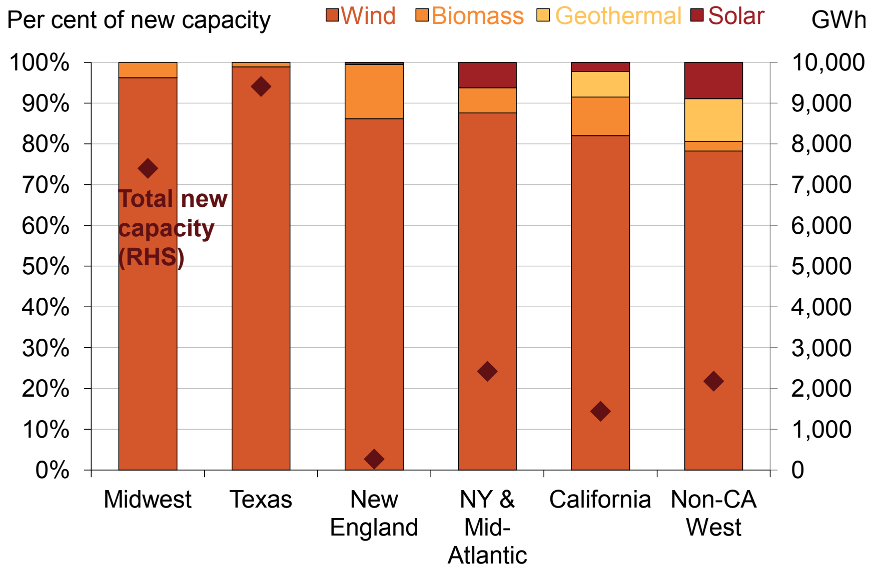
6.7.3 Portfolio of options

Complex modifications are needed to produce options

TGC schemes do not naturally deploy a range of technologies. Competition puts pressure on developers to seek out the lowest-cost technology options. Moreover developers, already exposed to substantial risk and uncertain of the future certificate price, tend to avoid technology experiments that might produce learning but would further increase their risk.

Focussing on the lowest-cost options is precisely how a market-based scheme ought to operate, and there is ample evidence to suggest that TGC schemes have done this.[88] To illustrate, in the US an overwhelming 94 per cent of the new capacity installed under state-based Renewable Portfolio Standard schemes has been delivered by wind power, in general the lowest-cost technology option (Figure 6.11).[89] Wind power accounts for practically all new RPS generation in Texas and the Midwest, where high-quality wind resources make it very attractive, able to produce power at about US$35 and $46-54 per megawattt-hour, respectively. The price of wind power tends to be higher in California and other western US states.

Figure 6.11 US renewable energy installed in RPS states 1998-2009



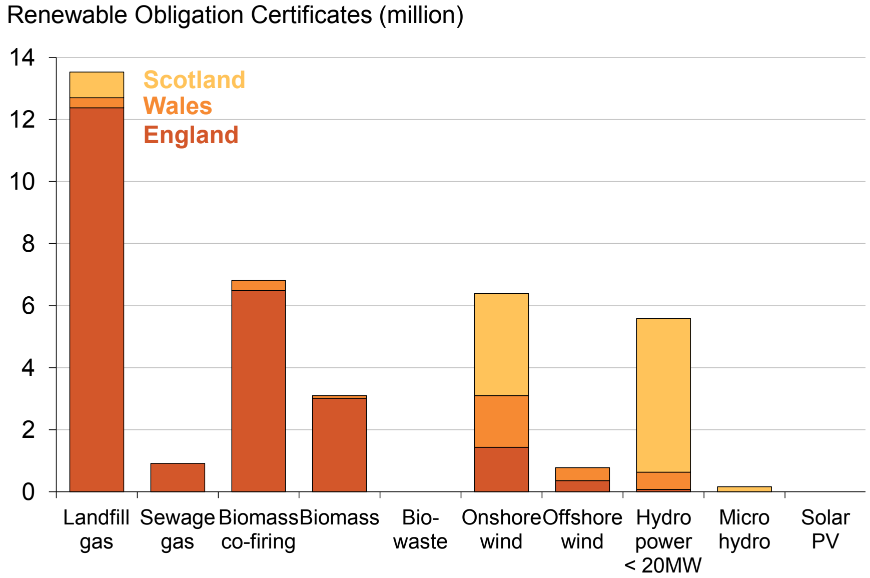
Source: Wiser et al. (2010)

[86] Johnston, *et al.* (2008). In this context, 'grandfathering' of certificate entitlements for existing projects can provide some assurance for investors. This has been implemented in the UK.
[87] Gipe (2006)
[88] Eg van der Linden, *et al.* (2005);Chen, *et al.* (2007);Wiser and Bolinger (2007);Fischer and Preonas (2010);Loomis and Ohler (2010);Powers and Yin (2010)

[89] See EIA (2010) for recent technology costs in the US.

Likewise, deployment under the Renewables Obligation (RO) scheme has reflected relative technology costs in the UK (Figure 6.12). According to UK Government figures published in 2011, landfill gas has been the cheapest option, at an average £45 per megawatt-hour, followed by biomass co-firing (£98-110 per megawatt-hour) and onshore wind power (£91-104 per megawatt-hour).[90]

Figure 6.12 UK Renewable Obligation Certificates issued April 2002 – March 2006



Source: Haas et al. (2011)

A TGC market will eventually bring more expensive technology options forward, but only when all the opportunities for lower-cost projects have been exhausted.[91] This is cost-efficient in terms of the overall scheme; again, exactly what the market-mechanism is designed to do. But it means that consumers must pay for many

[90] Department of Energy & Climate Change (2011a), Annex A p94. The levelised cost of sewage gas is also very low, at around £81/MWh, but a significant proportion of the technical potential has already been realised. The UK RO deployed about 8,500 MW of new capacity over 2002-10. It is thought that the UK scheme's effectiveness was reduced by several implementation issues, such as low penalty price, buy-out provisions that allowed recycling of penalty revenue to participants, planning constraints and no option to bank certificates Haas, *et al.* (2011), Mitchell and Connor (2004).

[91] As discussed earlier, investors are unlikely to invest in higher-risk technologies now on the basis of certificate prices being higher in the future, because of uncertainty about whether government will maintain the target and raise the penalty charge.

more projects, than is necessary to begin developing other options whose costs are higher today. To optimise technology cost-reduction, government support should tail-off as the technology cost-curve flattens out. However, TGC schemes do the opposite.

Government intervention is needed to make TGC schemes support a range of technologies at the same time. Governments can either increase the relative value of certificates produced by a specific technology or technology category (multipliers or banding) or they can devote a portion of the overall target to a technology (a carve-out or set-aside).

Such modifications are difficult to design and manage. Both approaches require government to specify which technologies should receive additional support and the optimal level of support, to adjust it as circumstances change and to decide when (if ever) it should end. This is similar to a feed-in tariff, but subsidising higher-cost technologies through the certificate market adds complexity. There are many factors that can alter how much impact modifications have, such as certificate market volatility, other TGC scheme changes and separate climate change policies.

Nevertheless, many governments have decided to adopt this approach. Australia has applied both these modifications to the RET. Banding was introduced into the UK RO scheme in 2009 and of the 30 RPS programs in the US, 26 have included rules to encourage specific technology types.[92]

[92] Wiser*, et al.* (2010)

Yet there are many examples of governments getting the settings wrong. In Australia, a five-fold multiplier was applied in 2009 for solar PV systems. The combination of a very generous multiplier and rapidly falling PV prices provoked a dramatic surge in supply, from 310,000 certificates in 2008 to 19.3 million in 2010.[93] Certificate prices crashed and the Government was forced to establish a separate market (a carve-out) for small-scale solar systems, to avoid large-scale projects being unviable. Today, solar PV continues to dominate the small-scale market.[94] By contrast, US states with multipliers of two or three have not seen significant changes in solar power deployment. It is thought that this number is too low to favour solar as developers continue to favour large-scale wind power generation.[95]

A broader disadvantage of multipliers is that they alter the relationship between certificates and electricity produced. This can mean that less low-emissions electricity is produced, diluting the overall scheme and further affecting the certificate price.

Carve-outs avoid the issue of overpayment because they are a miniature market in themselves. But government still has to specify the size of the carve-out and, eventually, may have to close it down. Moreover, the narrow carve-out market means less competition, which is normally a major benefit of TGC schemes.

[93] Australian Energy Market Operator (AEMO) (2011). Installations in 2010 represent those in that year plus many from 2009, which were attributed to 2010.
[94] Department of Climate Change and Energy Efficiency (2012). Multiplier credits are available for micro-wind turbines and hydro.
[95] Wiser (2007)

Total scheme cost is not capped, but effectively is under government control

Since electricity providers must purchase enough certificates to meet their obligations under the scheme, the price of certificates will in theory rise as much as necessary to meet the overall target. This increases total scheme cost, which in most cases is passed through to consumers. In practice this will happen only if government keeps the penalty rate for non-compliance higher than the average certificate price. If it does not, companies will opt to pay the penalty rate. Therefore, government in effect controls the total cost.

6.7.4 Feasibility

Likely to overlap with the ETS and interact with other government policies

As with the other approaches, indirect revenue support can be expected to depress the carbon price and discourage investment within the ETS. Therefore a TGC scheme may increase the economy-wide cost of meeting the same emissions-reduction target.[96]

Other government policies — such as energy project grants or loans, or energy efficiency policies — may also depress the certificate price. This is analogous to the impact of a TGC scheme on the carbon price discussed above. The interaction such policies may increase the total cost of meeting the TGC target.

[96] Garnaut (2008) p355

6.7.5 Predictability and Flexibility

History suggests that governments will change the rules

Certificate scheme design is complex. It requires government to make a number of significant decisions about scheme structure, size and application of targets, parameters for eligible technologies, rules to encourage resource diversity and penalty rates. The complexity raises concern about the likelihood of government review or rule challenges.[97]

However, most TGC schemes are established through legislation so they can offer investors greater certainty about their ongoing existence and ambition. Altering the target for how much low-emissions energy is to be produced usually requires a legislative change.[98] Grants or rebates, by contrast, are established through regulation. In both Australia and the United States, TGC scheme targets have only ever been made more ambitious and no schemes have been repealed, despite changes in government.[99] Further, certificate schemes are usually funded by a levy on electricity consumers and scheme administration costs are likely to be low, provided it is well-designed.[100] Future governments are

[97] Wiser, *et al.* (2004)
[98] Otitoju (2010)
[99] Wiser and Barbose (2008)
[100] In 2010 the RO cost just 0.22% of the scheme's value to administer Duncan (2011). In the Netherlands administration costs have been in the order of 2% of the price paid for certificates Faber, *et al.* (2000).

less likely to interfere with a policy that has no direct impact on the budget.[101]

Yet within these bounds governments have made changes more often than not. Ten EU countries adjusted their schemes in some way between 2005 and 2008.[102] The UK's Renewables Obligation has been altered in most years since its introduction in 2002. Of the 23 renewable energy targets in the US 11 were significantly revised in the four years prior to 2007.[103]

Changes can have major consequences for the balance of supply and demand. The probability of change can increase project finance costs and thereby the cost of the scheme overall.[104] In Connecticut, the list of eligible technologies was expanded to include several existing generators, causing certificate prices to fall from $35 to $5 over just a few months. Changes to Texas' Utility Commission's RPS calculation procedure saw certificate prices halve in that state within a year.[105]

Governments have a chequered history enforcing compliance

Penalty payments, sometimes called shortfall charges, apply to utilities that do not meet their obligations under the TGC scheme. They may be pre-specified, or set arbitrarily upon a violation. Either way they are necessary to the proper operation of the market. If they are set too low, funds will leak out of the scheme (utilities will pay the penalty instead of purchasing certificates), limiting project revenues and deterring investment.

There are recurring problems with penalty enforcement. Governments have capped the maximum penalty value (sometimes called a cost-cap) jeopardising interim targets.[106] Both New York and Arizona missed their carve-out targets as a result of having penalty cost-caps and being unwilling to increase the levy on electricity consumers. This curtailed investment.[107] Similarly, penalty waivers or exemptions have made schemes less effective. In some US states waivers are generous and eligibility is vague. Arizona for instance, accepts non-compliance 'for a good cause'.[108] The UK has repeatedly failed to meet its annual targets, partly because of its penalty design, which returned a share of the penalty revenues to the penalised parties.[109]

An arbitrary target creates uncertainty about the scheme in the longer-term

A TGC scheme target is arbitrary; it does not follow from a specific policy goal in the way that an economy-wide emissions cap should.[110] Therefore its long-term direction is also somewhat arbitrary and uncertain. Although the target is legislated, it can be expected that stakeholders will pressure government to make

[101] van der Linden, *et al.* (2005) This holds until the scheme cost becomes clearly visible in the electricity price and consumers may start to complain. At this point it can become unappealing for governments.
[102] Commission of the European Communities (2008)
[103] Rickerson and Grace (2007)
[104] Otitoju (2010)
[105] Cory and Swezey (2007)
[106] Blair, *et al.* (2006)
[107] Cory and Swezey (2007);Wiser, *et al.* (2010)
[108] Cory and Swezey (2007)
[109] de Jaeger, *et al.* (2011)
[110] eg the emissions cap should correspond with a level of national abatement consistent with limiting global warming to 2°C

changes according to current circumstance. This has occurred recently in Australia.[111]

Equally, the exact end point of a TGC scheme is arbitrary and probably will create market uncertainty. To end the scheme government will have to announce a cut-off date, or a capacity limit (in megawatts) that approximates the target (in megawatt-hours). If a date is used but the scheme then continues at this level,[112] there is some risk of undermining the ETS. If a date or a capacity limit is used and no new capacity is eligible to generate certificates, this could well spark a rush to complete projects ahead of the deadline — provoking a spike in new generation and prices, as Spain experienced (see previous section). Lastly, if instead the target were extended, this would increase the overlap with the ETS and increase uncertainty about the future of both schemes.

6.7.6 Design options to improve weaknesses

Modifications to reduce developer risk

A number of design options can reduce the cost of finance and overall risk for developers. Yet these tend to create further issues.

Predictable scheme reviews

Regulatory risk can be reduced, to some extent, by announcing scheme reviews well in advance. The scope of any review ought to be predictable and the timing of any changes should allow adequate lead-time for the private sector to react.

Certificate banking

TGC schemes generally require utilities to 'surrender' to government a specified number of certificates each year. Certificate banking allows surplus certificates to be carried over from their year of production for use in future years. This can be useful because electricity investments are often 'lumpy' — they have large, fixed upfront costs and initially may produce certificates in excess of demand.[113] Without banking, this value would be lost. Banking also makes the market more liquid, which tends to reduce costs overall.[114]

However, banking may discourage technology diversity. Banking reduces scope to quickly develop technology options, because it increases the supply of certificates from today's low-cost technologies.[115] This is the situation in Australia, where currently there is a significant oversupply of low-cost RECs that can be banked indefinitely (cf Figure 6.10 above).[116]

[111] eg Origin Energy CEO Grant King's recent comments reported in the *Australian Financial Review.* Macdonald-Smith and Priest (2012)
[112] ie allowing new generation capacity to be built, but freezing the penalty charge and the number of certificates to be surrendered each year. With this arrangement the certificate price should fall over time and the scheme should fade away. Eg Garnaut (2008);Garnaut (2011a)

[113] Panfil (2011)
[114] de Jonge*, et al.* (2008)
[115] Cory and Swezey (2007)
[116] Department of Climate Change and Energy Efficiency (2012)

Require long-term contracts for certificate supply

Governments can require developers and utilities to enter into long-term contracts for certificate supply. These provide developers with greater certainty about their future revenue and may mean that investors will provide finance at a lower cost.[117] TGC schemes that have required participants to sign long-term contracts, such as California (10+ years), Illinois, Ohio and North Carolina, have generally been more successful in meeting targets, and have seen compliance levels above the national average.[118]

It is unclear whether requiring participants to enter into these arrangements is beneficial. One view is that if long-term contracts are desirable then participants will negotiate them of their own accord.[119] Moreover, mandating long-term contracts can make it more difficult for small-scale generators to participate in the market, since their certificate supply is comparatively small and less regular (if they are renewable energy generators). This year California will make contracting optional rather than compulsory, in part to provide a more open market for distributed solar PV power.[120] Contracting also makes the certificate market less liquid and less transparent, since contracted prices are generally kept confidential.[121] This may depress competition and developers' incentive to reduce costs.[122]

[117] Gipe (2006)
[118] Cory and Swezey (2007);Hurlbut (2008)
[119] Kildegaard (2008)
[120] Johnson (2011)
[121] Gipe (2006)
[122] Kildegaard (2008)

Set a target in absolute terms

Although a TGC target is arbitrary, an absolute target, expressed in megawatts or megawatt-hours, is still more desirable than a target expressed in relative terms (10 per cent of energy from renewable sources, for example).[123] The latter links renewable generation to fossil fuel power generation. Expansion of one means expansion of the other, making it harder to predict the total amount of generation needed.

This is something to consider in the Australian context, where demand growth is dropping beneath projections, due to a range of factors.[124] Whichever approach is chosen, to avoid ambiguity it is important to select one and maintain consistency.

[123] Kneifel (2008). Targets in Australia and Texas are expressed in absolute terms, although Australia also has a (roughly corresponding) goal of 20% renewable energy by 2020.
[124] Australian Energy Market Operator (AEMO) (2012)

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