17 NETWORK INFRASTRUCTURE MARKET FAILURES

Key points

There is a risk that network infrastructure market failures relating to electricity grids and carbon dioxide transport systems could increase the cost of adjustment to a low-emissions economy.

The role of the proposed national transmission planner should be expanded to include a long-term economic approach to transmission planning and funding.

A similar planning approach is necessary to ensure that network infrastructure failures do not unnecessarily delay deployment of large-scale carbon capture and storage.

The Building Australia Fund should be extended to cover energy infrastructure.

There is a case for special feed-in tariffs for household electricity generation and co-generation. The case can be quantified by reference to timing and transmission considerations.

A well-integrated national energy network with the capacity to cope with potentially large shifts in flows will allow for structural change and the smoothing of shocks following the introduction of an emissions trading scheme and recent fuel price volatility.

The imposition of a price on emissions through an emissions trading scheme will drive demand for low-emissions goods and services. The price of emissions permits will depend in part on the availability of low-emissions alternatives, which in turn will rely on the infrastructure supporting those alternatives. Two important markets that will be particularly affected are energy and transport.

In energy, there are clear differences between the location and character of supply and demand today and into the future.

For energy, the transmission networks are geared to handle increments of supply from near the established grid, with consistent supply, on a large scale, and highly centralised. The new technologies tend to be far from the grid (geothermal, thermal solar, wind), have intermittent supply (wind, solar), operate on a smaller scale (including tidal), and be decentralised or embedded (photovoltaic solar, biomass). Without major change in the transmission infrastructure, new technologies will find it difficult to compete, even in circumstances in which they are expected to be highly competitive once compatible infrastructure has been established.

An emissions trading scheme will make higher-emissions forms of energy generation more expensive, shifting demand towards lower-emissions sources, and towards technologies that capture and sequester emissions. However, the extent to which consumers can express these preferences will be strongly dependent on the availability of appropriate network infrastructure to support the delivery of the new technologies.

In transport, an emissions trading scheme will make higher-emissions forms of transport more expensive, shifting demand to lower-emissions forms. Again, the degree to which consumers can express these preferences will be strongly dependent on the availability of lower-emissions transport and the appropriate network infrastructure.

A number of market failures may prevent the private sector from providing the optimal level of some forms of infrastructure services:

- **Public goods:** Infrastructure that is a pure public good (that is, non-rival and non-excludable) may be underprovided because the infrastructure provider is unable to capture the full benefits of its investment.
- **Natural monopoly:** Where infrastructure is best provided by a single firm, the firm may, without competition, underprovide and overcharge for use of the infrastructure.
- **Externalities:** Where infrastructure has positive or negative spillovers to third parties, the level of infrastructure provided may not be socially optimal. Subsets of externalities in infrastructure important to the supply of energy and transport include:
  - **Early-mover spillovers:** The first individual or firm to invest in infrastructure may face all of the costs, but some of the benefits accrue to later movers.
  - **Coordination externalities:** Private companies may not coordinate to provide infrastructure where trust is low or the cost of reaching agreement is high.

There may be circumstances in which private activity can overcome the failures. Occasionally the cost of a market failure will be more than the cost of government intervention, with all of its political economy and other risks and costs. In these cases, regulatory or fiscal intervention by government may be required to ensure an optimal response.

This chapter discusses market failures in:

- infrastructure for the transmission of electricity
- infrastructure for the distribution of electricity
- infrastructure for the transmission of gas
- infrastructure for the transportation of carbon dioxide for geosequestration.

Transport and urban planning infrastructure and services will be discussed in the Review's supplementary draft and final reports.

Because the vast majority of electrical energy in Australia is bought and sold on the National Electricity Market,[1] the Review's analysis of barriers to electricity infrastructure provision will focus on that market.[2] That said, the analysis of potential problems and solutions will be relevant to the other electricity markets in Australia.

17.1 Infrastructure for the transmission of electricity

17.1.1 Public good aspects of electricity interconnectors

In the National Electricity Market, electricity is imported into a region when demand exceeds the capacity of local generators, or when the price in an adjoining region is low enough to displace the local supply. Interconnectors are the high-voltage transmission lines that transport electricity between adjacent regions. However, an interconnector's ability to transfer electricity is limited by the extent of its physical transfer capacity. When the technical limit of its capacity is reached, an interconnector is constrained.

The adequacy of interstate interconnection will be a key infrastructure issue for the National Electricity Market in the near future. There are two public good arguments for reducing these constraints in light of the expected changes required for Australia's transition to a carbon-constrained future.

First, adequate interconnection will allow the National Electricity Market to accommodate any structural change in the electricity sector that may be required. The emissions trading scheme will deliver quick and profound shifts in the fundamental relative economic values of low- and high-emissions forms of electricity generation. Dramatic price changes for fuel source commodities such as tradable coal and natural gas would also contribute to the pressures for structural change. Both the permit price and international commodity prices will result in changes to the regional comparative advantages associated with different fuel sources.

There will therefore be a special need for a network of interconnectors with enough capacity to cope with the potentially large shifts in interstate flows of electricity over time. Market fragmentation due to limited interconnector capacity means much of the generation capacity must remain within a region, even if there are more economic sources elsewhere.

For example, the high price of export coal may make brown coal electricity from Victoria cheaper than black coal electricity produced in New South Wales, even with the permit price. However, interconnector constraints between these regions may mean that local demand in New South Wales still has to be met by black coal generation. Alternatively, a large fall in black coal export prices may generate the opposite pressures. The inability to capitalise on comparative advantage may thus adversely affect the economic fortunes of both brown and black coal producers. Confidence in the capacity of a national system will be particularly important for the period of transition, and interconnector constraints will have a high opportunity cost in the form of higher energy and higher emissions permit prices.

While it may seem inefficient to have permanent abundant excess capacity in the interconnectors between regions, in the world of structural change Australia is entering, it could become more likely that generation cost differences will exceed the distribution losses and infrastructure costs. A fine balance will be required: there needs to be adequate interconnector capacity that promotes efficiently located generation, but not to the extent that the sunk costs of that capacity outweigh the public good benefits.

Second, adaptation to climate change and more frequent disruptions of electricity supply will require deeper interconnection capacity. Having excess capacity in interconnectors provides additional security for the system as a whole.

Adequacy of current arrangements

At present, interconnector constraints do not appear to be significant; the most constrained interconnector is DirectLink from New South Wales to Queensland, which was constrained for 285 hours in 2005–06 (Energy Supply Association of Australia 2007). That being said, any investments in additional generation capacity could be deferred in the light of limited interconnection capacity.

The current regulatory arrangements provide for the sharing of interconnection costs between the regions involved, subject to a dual test of reliability and market benefits. While the same tests can be applied when delivering these benefits across state boundaries to balance supply and demand and while the benefits of reliability often accrue to both regions, there may be situations where one region reaps most of the benefits. In these circumstances, the sharing of costs may be a challenge.

One obstacle to the construction of additional interconnector capacity could be state government protectionism in relation to native energy generation. State governments may place limits on interconnectors to ensure that local generators are able to maintain market share within their region.

Interconnectors can also be privately provided. The recent announcement of a private transmission line from central Queensland to the Hunter Valley suggests that the current regulatory and investment environment is providing the opportunity and incentives for investment in interconnectors where economically appropriate.

Reforms to the regulatory and institutional arrangements for the planning and funding of improvements to interconnector capacity are under way. The key focus of reform should be the facilitation of new private interconnection capacity. Attention should be given to whether there are adequate private incentives to install socially optimal levels of capacity to allow flexibility in the amount of interstate electricity trade.

17.1.2 Market failures in transmission network extensions

Many new sources of electricity could come from areas not currently serviced by transmissions lines or, alternatively, where the electricity distribution or transmission network is not currently able to cope with the additional energy output from new generators. In either case, extension or augmentation of the transmission network may be warranted. There are, however, two barriers to successful network augmentation that could significantly slow or even halt the progressive deployment of lower-emissions generation technologies.

Free-rider problems and first-mover disadvantage

The current regulatory regime requires those seeking connection to cover the cost up to the point of connection. For a single remotely located generator (including wind, solar and geothermal) the additional cost of connection is likely to be insurmountable. If the costs can be shared between multiple generators, the likelihood of a successful network extension increases, but still may not eventuate because there is a strong incentive to free ride on the efforts of early movers.

The first party (or parties) that connect to the network are faced with all the cost of extending the network. Later parties are then able to connect to the expanded network at a substantially reduced cost. The incentive is therefore for potential larger-scale generators to delay the development of their investment in the hope that others will take the first step, or to select plant sizes and locations that simply ‘use up’ existing capacity in sections of the grid.

Barriers to achieving optimal scale in network extensions

Current processes for extending the electricity network are likely to be suboptimal from a societal perspective because they do not provide any mechanism for the exploitation of economies of scale. In some circumstances, it may be desirable to provide additional transmission network capacity ahead of generation capacity. At present, additional network capacity can only be funded by the broader customer load if it is the best alternative to meet reliability requirements or provides net market benefits. From this perspective, it will usually be better not to install the additional network capacity until there is concrete proof of need,[3] and so projects may not install new capacity at a socially optimal scale.

Funding for network capacity will thus depend on the project proponent, who will have no incentive to fund a larger capacity than required. When the next project to develop a resource in close proximity is proposed, the transmission network will have to be augmented, and the additional cost will exceed the incremental cost of the new capacity had it been built into the network from the outset.

These tendencies are exacerbated by the long lead times for transmission investment compared to the shorter lead times for generation capacity or changes to demand load. Responses to these market signals will typically come too late.

17.1.3 Expanded role for proposed national transmission planner

Current electricity market reforms propose the introduction of a national transmission planner[4] to promote the development of a strategic and nationally coordinated transmission network. The proposed planner would have regard to 'the most efficient combination of transmission, generation, distribution and non-network options that will deliver reliable energy supply at minimum efficient cost to consumers under a range of credible future scenarios' (Australian Energy Market Commission 2008: 10). It would also take into account demand side, embedded generation and fuel substitution alternatives (see Australian Energy Market Commission 2008).

These new arrangements are expected to deliver a coordinated and efficient national transmission grid that meets local and regional reliability and planning requirements, and is flexible enough to respond to generation and load changes.

The core function of the national transmission planner will be to prepare and publish a national transmission network development plan each year. An integrated long-term development plan will contribute to improving the efficiency of transmission network investment decisions by providing signals for efficient generation investment (see Australian Energy Market Commission 2008).

The Review endorses the recommendations for national transmission planning arrangements in the draft report by the Australian Energy Market Commission (2008), and proposes that the role of the national transmission planner be extended to incorporate (1) an economic approach to transmission planning and (2) financial incentives for priority projects.

An economic approach to transmission planning

The Review endorses the Australian Energy Market Commissions' proposed recommendation that the national transmission network development plan should 'present a broad and deep analysis of different future supply and demand scenarios ... taking account of various policy, technology and economic assumptions and looking out at least 20 years into the future' (Australian Energy Market Commission 2008: 23). The Review proposes that the national transmission planner also adopt an economic approach to transmission planning that covers more forward-looking demand and supply scenarios, rather than simply focusing on technical feasibility. The Renewable Energy Transmission Initiative in California provides some important lessons for such an approach (see Box 17.1).

The national transmission planner could undertake a similar process to that followed in California's Renewable Energy Transmission Initiative, but unlike the California initiative, the planning process should be technologically neutral and consider potential projects for both the renewable and non-renewable fuels. The process would start with a resource assessment that builds on existing assessments. Resource assessments typically stop short of identifying economically 'developable' potential, and are thus inadequate for use in transmission planning. Instead, the planner would analyse the resources considered in previous studies and identify the most cost-effective developable renewable resources in areas throughout Australia. Among other things, this analysis should also take into account engineering feasibility and environmental factors that may not have been considered in previous studies in order to avoid areas that cannot be developed for technical or environmental reasons.

This analysis would be informed by a comprehensive stakeholder consultation process with private sector generation companies. Firms would submit proposals and estimates of the costs of developing the generation resources within an area and delivering that energy to consumers. These project and technology costs would by necessity be estimates, intended primarily to provide information to compare areas. The open and transparent process would support the emergence of a consistent set of assumptions.

Ultimately, based on analysis of developable potential, comparative economics and other factors, resource areas would be grouped into high-demand zones. These areas would then be prioritised to allow identification of economically efficient suitable network extensions.

Financial incentives for priority projects

The Australian Energy Market Commission (2008: ix) states that, 'the [national transmission planner] will be required and resourced to produce its own development strategies, including its own transmission investment options'. The Review proposes that in addition to the identification of options, financial incentives are necessary to overcome the free-rider issues of transmission augmentation. Incentives can reduce the likelihood of transmission extensions being hindered by early-mover problems, and help to ensure that augmentation is undertaken at a socially optimal scale.

Box 17.1 California's Renewable Energy Transmission Initiative

The Renewable Energy Transmission Initiative is a statewide initiative of the California Energy Commission that aims to identify the transmission projects needed to accommodate the state's renewable energy goals. The purpose of the initiative is to bring together all of the renewable transmission and generation stakeholders in the state to participate in a consensus-based process to identify, plan and establish a rigorous analytical basis for regulatory approvals of the next major transmission projects needed to access renewable resources.

The initiative will assess all competitive renewable energy zones in California (and possibly also in neighbouring states) that can provide significant electricity to California consumers by the year 2020. It also will identify zones that can be developed in the most cost-effective and environmentally benign way and will prepare detailed transmission plans for zones identified for development.

The effort will be supervised by a coordinating committee made up of California entities responsible for ensuring the implementation of the state's renewable energy policies and development of electric infrastructure. There are five core steps to the process:

1. identifying competitive renewable energy zones having densities of developable resources that best justify building transmission to them
2. ranking zones on the basis of environmental considerations, development certainty and schedule, and cost and value to California consumers
3. developing conceptual transmission plans to the highest-ranking zones
4. supporting the California Independent System Operator Corporation, investor-owned utilities and publicly owned utilities in developing detailed plans of service for commercially viable transmission projects
5. providing detailed analysis regarding comparative costs and benefits to help establish the basis for regulatory approvals of specific transmission projects (starts in steps 1 and 2, but is revised based on new information developed in steps 3 and 4).

The Office of Gas and Electricity Markets in the United Kingdom undertakes a similar exercise with its long-term electricity network scenarios.

Source: RETI Coordinating Committee (2008).

As currently conceived, the national transmission network development plan will outline the strategic long-term development of the transmission network, but network service providers will still be responsible for upgrading their transmission systems. The national transmission planner will not be empowered to compel any particular investment outcome[5] and investment decisions will remain wholly with service providers.

The national transmission planner can play a more substantive role in the development of National Electricity Market network infrastructure by adopting a planning process that identifies and coordinates the overarching interests of transmission network service providers and new entrants and by providing the national transmission planner with a pool of funds to support suitable network projects.

It is envisioned that for appropriate projects, early movers and the national transmission planner would share the initial upfront capital costs of the infrastructure project. Public funds managed by the planner would be used to pay for the portion of capacity that would be expected to be taken up by later market entrants. The regulatory structure would include arrangements that allow the planner to recover its investment from later users either through access charges or, preferably, eventual sale of the asset into private ownership. To ensure that network economies of scale are exploited, the fund would need to be sufficiently large to bear the upfront investment costs incurred during the initial phases of augmentation, up to the time that the full capacity of the network is utilised.

It is proposed that funds be made available for this purpose from Infrastructure Australia, and its newly established $20 billion Building Australia Fund. The Building Australia Fund is currently earmarked for national transport (roads, rail and ports) and communications infrastructure (broadband) that cannot be delivered by the private sector or the states. It would be appropriate for the Building Australia Fund to be extended to finance high-value national electricity transmission infrastructure.

17.2 Infrastructure for the distribution of electricity

17.2.1 Externalities of embedded generation

There are three main externalities of embedded generation that may contribute to inefficient investment decisions. The possible inefficiencies relate to overinvestment in network infrastructure and centralised generation, and underinvestment in embedded generation like solar photovoltaic and cogeneration.

- **Reduced transmission losses:** Energy losses from electrical resistance in transmission cables are significant when electricity is transported over long distances. The average weighted distribution loss in Australia in 2005–06 was 5.9 per cent, with the highest loss factor of 7.2 per cent in Tasmania (Energy Supply Association of Australia 2007). Embedded generation does not suffer transmission losses to the same extent as generation located far from demand centres.[6] However, current rules do not provide recognition for the reduction in losses that embedded generation brings to the system. While National Electricity Market rules currently require network businesses to pass on these savings[7] to larger embedded generators, there is no requirement to similarly compensate the smaller embedded generators.
- **Benefits of deferred network augmentation:** During times of peak system demand, the marginal network costs are much higher than the averaged network charges faced by customers. This is because the cost of network augmentation to manage system load is driven solely by the extent of peak demand. The costs of building and maintaining infrastructure capacity increase with the level of the peak. Any embedded generation at peak periods helps to avoid or defer the high costs of network augmentation. In an efficient market, the price paid for electricity supplied would include the benefits of avoided network augmentation.
- **Higher value of energy supplied during peak periods:** There is significant variability in the wholesale price of electricity in Australia. For example, in 2005–06 the average volume weighted price for electricity in New South Wales was $43.04 per MWh—but there were spikes in the spot price in the peak summer periods of up to $9738.95 per MWh (just below the market bidding cap of $10 000 per MWh) (Energy Supply Association of Australia 2007). However, because embedded generation does not participate in the wholesale market, it does not experience these price spikes—either higher during peak periods or lower during off-peak periods. This is mainly an issue during peak periods, when embedded generation may be more competitive with more expensive forms of centralised generation and therefore more likely to be profitable.

These three externalities from embedded generation can be seen in the market for small-scale solar photovoltaic generation. Solar photovoltaic generation that provides energy during high demand periods is significantly undercompensated for its lower levels of losses, network benefits and timing of supply. This will increasingly be the case as temperature rises, since daytime peaks in demand as a result of air conditioner use would correlate more strongly with solar photovoltaic output.

The current regulatory framework encourages and rewards investment in infrastructure because revenue is directly related to the value of the asset base. This means that deferred augmentation as a benefit of embedded generation would be in direct conflict with the incentive structures for network businesses, making suboptimal investment decisions even more likely.

To date, feed-in tariff policies have been implemented primarily on the basis of infant industry assistance. This is not a valid reason for support. The market failure associated with new industries is best corrected by providing direct support for research, development and commercialisation of new technologies (see Chapter 16). If this were the sole basis for higher feed-in tariffs, its application would raise the cost of the transition to a low-emissions economy.

There are, however, valid economic arguments for an appropriate feed-in tariff regime, at levels commensurate with the associated external benefits.

17.2.2 What should the value of a feed-in tariff be?

There are two main ways by which feed-in tariffs can be paid—gross metering and net metering. Gross metering pays the embedded generator for all electricity it generates, while net metering pays for just the energy exported to the grid (gross generation minus local energy consumed).[8] Feed-in tariffs in Spain and Germany, for example, are calculated on a gross-metering basis. In Australia, most feed-in tariff commitments have been based on the net quantity of energy exported to the grid.

For small embedded generation systems installed by households or firms that are consuming electricity throughout the day, it is likely that no exports to the grid will be possible. However, the benefits of embedded generation (lower transmission losses, deferred costs for network augmentation, and displacement of high-cost generation during peak periods) are present for every unit of electricity produced, not just the amount exported. A feed-in tariff based on gross metering is thus a more accurate means of pricing these benefits.[9]

17.3 Gas transmission infrastructure in Australia

Australia's gas transmission system is privately owned, and today serves the dual purpose of connecting gas fields to gas markets and interconnecting regional systems. Interconnections provide a degree of supply diversity and security.

Do the market failures identified in section 17.1 for electricity transmission also apply to gas? While the theoretical impediments, such as first-mover and free-rider barriers, do, no doubt, exist in the gas market, there is evidence that the market has been able to overcome them.

First, Australia's east coast gas transmission system underwent rapid expansion over the last 30 years through private sector investment, with little need for government intervention. The network has expanded to support the growth in demand and the diversification of supply sources—all through the private sector ownership structure. In some cases, pipelines originally built by state governments are now under private ownership.

A recent example illustrates the way in which this market has functioned efficiently without government intervention. The SEA gas pipeline connects the Victorian and South Australian gas systems through its link between Port Campbell and Adelaide. The pipeline was the outcome of an alignment of the joint interests of gas producers in Victoria and a gas generator and gas retailers in South Australia, and was ultimately constructed as a three-way joint venture. In addition to direct access for Victorian gas to the South Australian market, the pipeline provides diversity and security of supply to both states directly, and to the overall east coast market indirectly.

Second, in contrast to electricity transmission, the majority of Australia's gas transmission pipelines are not regulated. Pipeline owners use pricing structures with their shippers that have avoided such a requirement.

One key driver for this outcome is that gas pipeline developers and owners are able to contract directly with shippers. This contrasts starkly with the electricity market. Parties with a vested interest in the development of a gas pipeline, such as gas producers, wholesalers, retailers or major end-use customers, have been able to align their commercial interests to deliver the requisite facility.

There is no reason to suggest that existing impediments would be any more significant following the introduction of an emissions trading scheme. Lessons should be drawn from the circumstances that have led to this market operating efficiently without government intervention.

17.4 New infrastructure for the transportation of carbon dioxide

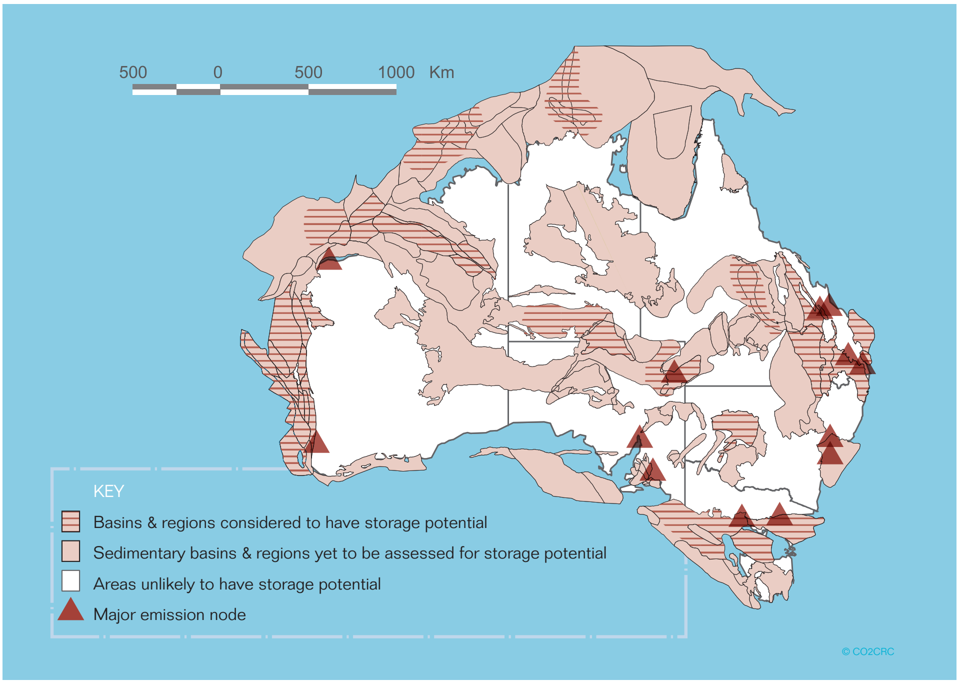
17.4.1 Infrastructure challenges for the transportation of carbon dioxide

Due to the relative immaturity of the technology for geosequestration of carbon dioxide, current projects in Australia are located close to storage sites of varying capacities. This close proximity eliminates the costs of transportation over long distances.

As the number of sources and discovery of suitable sites increases, there will be a corresponding increase in the need for pipeline networks to transport carbon dioxide between locations. In the long term, some suitable sequestration sites could be relatively isolated, requiring an even larger pipeline network. There may also be good arguments for locating a point source far from a sequestration site if the source needs to be close to a natural resource that is expensive to transport. The current location of many coal-fired power plants close to coal seams is an example.

While fossil fuel electricity generation is the primary candidate for geosequestration technologies, transport infrastructure policy must be flexible enough to cope with a variety of non-electricity-related carbon dioxide applications.

Figure 17.1 Major sequestration sites and carbon dioxide sources in Australia



Source: Image courtesy of CO2CRC.

Carbon dioxide gas is most efficiently transported when compressed to a supercritical state (a temperature and pressure at which it shows properties of both liquids and gases). Because of its potential corrosive effects, water (and possibly some contaminants) is removed before transport. Compressing carbon dioxide also enables the injection and storage of greater volumes. Carbon dioxide can be transported by truck, rail or, in the case of a geological storage site deep beneath the seabed, by ocean tanker. However, pipelines are the economic mode for transporting large amounts of carbon dioxide for distances of up to 1000 km. This method of transporting pressurised carbon dioxide is already a mature technology. In the United States, for example, about 40 million tonnes per year travels through a 2500 km network of high pressure pipelines (mainly in Texas) for the purpose of enhanced oil recovery (International Energy Agency 2001).

17.4.2 Potential roles for government

Government needs to consider the future need for a system of pipelines for transporting carbon dioxide from the point of capture to the point of storage. There is a potential for market failures in the provision of such a pipeline network in three phases.

Pre-commercial planning

While carbon dioxide geosequestration technology matures and approaches commercial feasibility, an appropriate independent body could start assessing appropriate carbon dioxide sources, sequestration sites, existing projects and potential future projects. This process could go beyond a study of technical feasibility, and explore economic competitiveness based on consultation and proposals from the carbon capture and storage industry. The aim would be to identify the major centres for carbon dioxide capture and sequestration around Australia, and thereby highlight some of the possible long-term priorities for key pipeline infrastructure.

Government should not act on its plans for physical infrastructure until substantial demand has been confirmed. However, planning and foresight are necessary given the long lead times between the recognition of need and the completion of any infrastructure project of this scale.

Establishment

Once the industry has matured to the point of being potentially commercially competitive, government will need to be prepared with efficient mechanisms for initial development and funding of a pipeline grid. As has been the experience with the gas industry in Australia (see section 17.3), it is possible that the physical infrastructure for carbon dioxide transport could be successfully provided by the private market, thereby requiring minimal intervention by government. If the private market can overcome the natural monopoly market failures and coordination failures that are characteristic of network infrastructure, this would be the preferred outcome.

However, the magnitude of these market failures or the cost of delays in overcoming them may warrant government intervention. This could involve supporting the construction of the main pipelines at a socially optimal scale, regulating pipeline construction, providing a contingent subsidy, or providing adequate information regarding sites and sources. If government funding were required in the establishment phase then future users should be charged for use of the spare capacity so that the funds could be recovered. Government could divest itself of the asset by sale to a private operator as the pipeline approaches full utilisation.

As discussed in section 17.1.3 in relation to electricity infrastructure augmentation, a program (also based on the Californian Renewable Energy Transmission Initiative) could provide an efficient mechanism to determine the initial coverage and scale of a carbon dioxide pipeline grid. As discussed in section 17.1.3, it would be appropriate for the body administering the resource assessment process to be able to fund identified carbon dioxide pipeline priorities (with some excess capacity to cater for additional users in the future) if this proves to be necessary. Arrangements for cost recovery and eventual sale to the private sector should be structured so as to maintain incentives for purely private pipeline investment.

Long-term management and access

Since the pipeline system would be a natural monopoly, access arrangements for multiple users may be required. The gas industry has privately established these arrangements; the carbon dioxide sequestration industry may be able to do the same. If not, the Australian Competition and Consumer Commission would need to establish an appropriate regime.

Notes

1 The National Electricity Market is a wholesale market for electricity supply covering the Australian Capital Territory and the states of Queensland, New South Wales, Victoria, Tasmania and South Australia. In 2005–06, approximately 88.6 per cent of electricity generated was sent out in the National Electricity Market.

2 The report commissioned by the Review from McLennan Magasanik Associates contains detailed discussion of market failures in the National Electricity Market (see www.garnautreview.org.au).

3 This onerous burden of proof is necessary to ensure that only essential infrastructure extensions are undertaken and to avoid the possibility of multiple underused extensions to the grid.

4 The Council of Australian Governments and the Ministerial Council on Energy have provided some guidance and prescription on the characteristics of the new arrangements.

5 The Council of Australian Governments has explicitly agreed that the national transmission network development plan will not replace local planning or bind transmission companies to specific investment decisions, override network service providers' performance standards, or constrain the time frames for the revenue approval process for transmission companies.

6 There are technological solutions to transmission losses such as lower-resistance power lines, but the capital costs are currently prohibitive.

7 This is known as the avoided transmission use of system charge.

8 The selection of the type of tariff will depend on the technological capabilities of the meters installed.

9 Some argue that a gross-metered feed-in tariff is undesirable because, from a sustainability perspective, it does not encourage embedded generators to consume less electricity, whereas under a net-metered scheme profits can only be made by exporting more to the grid. This reasoning is erroneous because the incentives to consume should come through the retail tariff paid for electricity, not through the feed-in tariff system.

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