

ROLE OF GEOTHERMAL ENERGY IN SECURING LOW CARBON EMISSIONS OPTIONS FOR THE AUSTRALIAN AND GLOBAL STATIONARY ENERGY SECTOR

**Critical considerations relating to government support for research
and commercialisation**

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Executive Summary	3
1. Context and Purpose.....	5
2. Background.....	5
a. Enhanced Geothermal Systems (EGS) Electricity Supply.....	5
b. The Size of the EGS Resource.....	6
c. Long Run Marginal Cost (LRMC) of EGS compared with alternative baseload supply options for eastern Australia.....	7
a. Knowledge development and transfer.....	8
b. EGS – a zero carbon electricity, low risk electricity supply option for Australia.....	9
c. Global EGS opportunities.....	11
4. Market and Regulatory Barriers to Geothermal Baseload Supply.....	11
a. Pathway to mature plant economics	11
b. Closing the gap between capital market risk appetite and new entrant economics.....	12
c. Provision of transmission infrastructure	13
5. Options for Addressing Market Failure	14
a. Allocating priorities and resources – framing considerations and proposed criteria	14
b. Methods of assistance.....	15
Annex 1: Approach and assumptions used for modelling of LRMC of alternative baseload supply	17
Annex 2: Geodynamics international cooperation on EGS development	18
Annex 3: Illustrative outline of Low Emission Guarantee Company (LEG Co)	20

Executive Summary

This submission to the Garnaut Climate Change Review addresses a number of issues raised in the Review's Issues Paper 4, "Research and Development: Low Emissions Energy Technologies" and also discusses a number of broader themes relevant to moving Australia and the world on to a dramatically lower carbon emissions path.

Briefly, EGS resources in the Cooper Eromanga Basin alone are sufficient to displace Australia's entire current coal fired generation (~30,000 Mwe capacity) for more than 250 years. Globally, China and India, the world's fastest growing coal fired electricity markets, both have substantial EGS energy resources that have the capability to displace very large elements of baseload capacity that would otherwise be met from coal or nuclear generation.

The long run marginal cost for mature EGS plants is competitive with fossil fuel based power when taking account of carbon pricing, the need for carbon capture and storage in fossil fuel based power generation and trends in global and domestic gas markets. Near term geothermal investment therefore provides the basis for both domestic and overseas electricity supply to transit to much lower carbon emissions at lower risk than fossil fuels or nuclear.

In terms the case for public support for bring to market, Geodynamics' experience is instructive. The company has so far spent some \$150m. To date, its activities have exhibited important technical and industry capability spillover effects. This knowledge transfer will continue as remaining key risks to be resolved are addressed in the development of the first 50 Mwe commercial scale demonstration unit.

Completion of this unit will establish EGS on a commercially sustainable pathway to mature EGS plant economics involving a build out to some 400-500Mwe over the period 2011-2016. Important barriers, however, to this commercialisation remain in the form of the interaction between:

- the gap between early plant economics and equity/debt markets appetite for risk/reward (the "valley of death" problem discussed in the R&D Issues Paper); and
- the current regulatory arrangements governing the provision of transmission infrastructure that disadvantages new entrants, particularly in remote locations.

These problems exemplify the challenges of bringing new low carbon technologies into the market in the face of entrenched legacy advantages enjoyed by conventional energy supply options. Geodynamics therefore believes there is a compelling case for public support for the development and early commercialisation of low emissions technologies. Such support should be directed to projects that:

- Are demonstrably additional to what the proponent would have undertaken in the absence of the support.
- Demonstrate sufficient Australian resource to realistically supply a substantial proportion of Australia's energy needs over the period to 2050, with a preference for projects/technologies that can achieve early cost effective build out at scale.
- Have a very low environmental impact overall (including both zero/very low emissions), and be sustainable in the long term in terms of the size of the resource and its ongoing environmental impacts.
- Have a demonstrably realistic chance of commercialisation at scale domestically and internationally.

- Are capable of potentially leveraging a significant multiple of private sector funding.

Broadly, there are four possible ways of providing public financial support for the development and commercialisation of low emissions technology: payments through the tax system; direct subsidies in the form of grants or loans; government equity investments; and loan/financing guarantees

In principle, any of these methods can be configured to have the same impact from an investor risk/return point of view. Given the nature of the policy problem under consideration – the acceleration of development/commercialisation of low emissions technologies - support through the tax system would still need to be evaluated against selection criteria of the type suggested above. In large measure, therefore, the choice of mechanism is a second order issue which should be driven by considerations of transparency and ease of administration.

In general, Geodynamics favour a straightforward grant scheme with competitive qualification against the criteria suggested above. This would be simple to administer and would provide a clear incentive for private investors to control capital expenditure and manage technical risk. Government/societal carbon portfolio risk (arising from over concentration on one technological option) could be managed by ensuring a requisite degree of diversity constrained by the proposed selection criteria, including support for strategic transmission investments that facilitate development of competing low carbon energy supply solutions.

1. Context and Purpose

This submission addresses a number of issues raised in the Review’s Issues Paper 4, “Research and Development: Low Emissions Energy Technologies” and also discusses a number of broader themes relevant to moving Australia and the world on to a dramatically lower carbon emissions path.

In particular, it seeks to address the important questions relating to the existence of public good or spillovers and/or capital market failures as a basis for identifying potential candidate technologies for public support; and the methods by which such assistance might be offered in ways that strike an appropriate balance between, on the one hand, spreading assistance too thinly to produce results and, on the other, choosing a reasonably diversified portfolio of options to insure against technological and commercial uncertainties (the “picking winners” problem).

The rest of this submission sets out the evidence for:

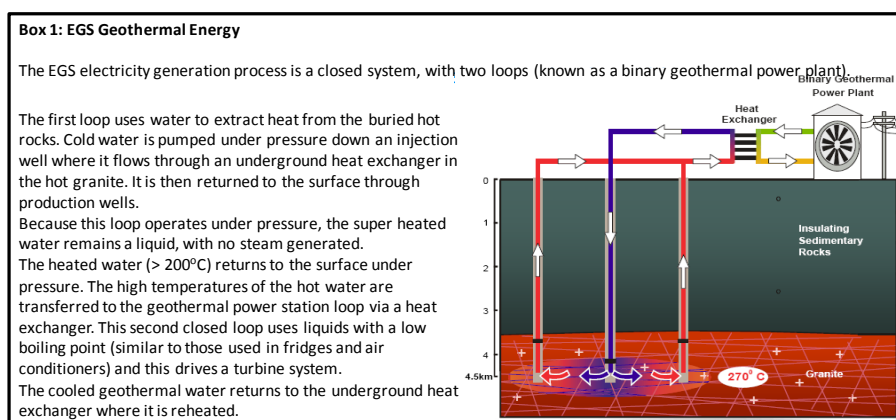
- Actual and major potential public good and spillover impacts from the scale deployment of baseload electricity supply from geothermal energy based on hot fractured rocks in Australia and overseas;
- the existence of market and regulatory barriers to this scale deployment; and
- the resulting need for, and possible form of criteria and mechanisms of government support to address these barriers in order to provide domestic and international options for deployment of near zero carbon baseload electricity supply.

2. Background

a. Enhanced Geothermal Systems (EGS) Electricity Supply

EGS geothermal energy relies on the presence of high heat production granites deep underground, typically at depths of between 3 and 6kms. These granites have special naturally occurring radiogenic minerals which produce their own heat. The heat is trapped inside these granites by an overlying blanket of insulating rocks. Such a blanket has to be about 3km thick for the temperatures of over 200°C to be maintained that are necessary for economically viable large scale electricity production.

To generate electricity the heat is extracted from these granites by circulating water through them in an engineered, artificial reservoir or underground heat exchanger. The heat energy from the superheated water is then transformed into electrical energy via a surface based heat exchanger and turbine system (Box 1.)



As the energy is derived from converting heat extracted from hot rocks there are no gas emissions. Unlike burning fossil fuels, no CO₂ is therefore released into the atmosphere. The process does not produce any waste dumps and has a low noise impact. The construction of a HFR geothermal power plant leaves only a small environmental footprint. Site disturbance is limited to drill holes and pipelines, and a building to house the power plant.

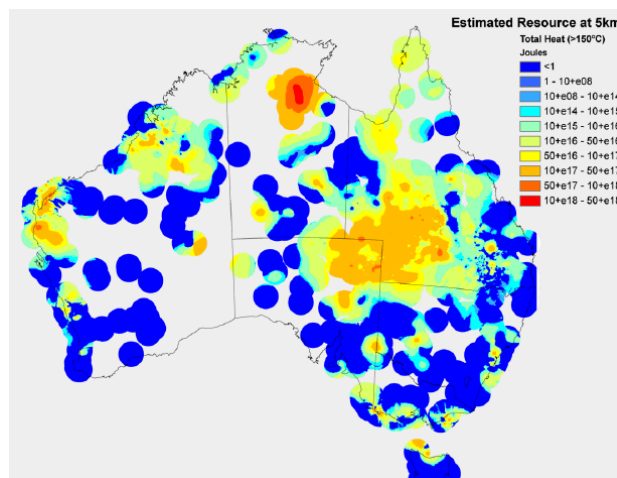
EGS based electricity is thus the only source of renewable, low environmental impact energy with a capacity to carry large base loads 24 hours per day. This makes it the only known zero carbon energy source with the recognised potential to replace fossil fuels, rather than just augment them, as is the case for most other renewable energy sources.

b. The Size of the EGS Resource

Heat producing granitic rocks are very widespread in Australia and globally. The required combination of hot deep granitic rocks and a 3km insulating overlay to generate temperatures of 200°C required for commercial generation is more restricted but still constitutes a very large potential baseload energy source. For Australia Geosciences Australia has estimated an EGS minimum thermal energy resource of 120,000 Exajoules (Figure1).

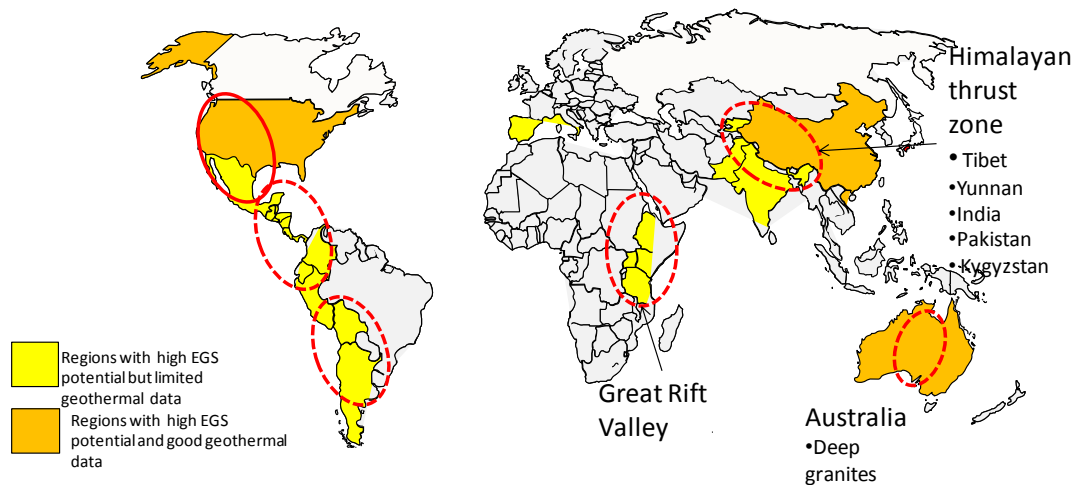
The estimated resource in Cooper Eromanga Basin alone is estimated to be 10,000 Exajoules (2 Exajoules/25KM² over 120,000 Km²). This is sufficient to displace Australia's entire current coal fired generation (~30,000 Mwe capacity) for more than 250 years.¹

Figure 1: Australian EGS Energy Resources at 5km (Source: Geosciences Australia)



Globally, China and India, the world's fastest growing coal fired electricity markets, both have substantial EGS energy resources. The USA, the world's largest energy consumer also has very large EGS resources (Figure 2).

¹ Assumptions: 20% thermal energy recovery and 12% electricity conversion; >35,000 MWe capacity for 250 years; 2007 Australian coal fired capacity ~ 30,000 Mwe; developable Cooper Eromanga Basin EGS capacity by 2050 >30,000 Mwe

Figure 2: Global EGS Resource Potential

c. Long Run Marginal Cost (LRMC) of EGS compared with alternative baseload supply options for eastern Australia

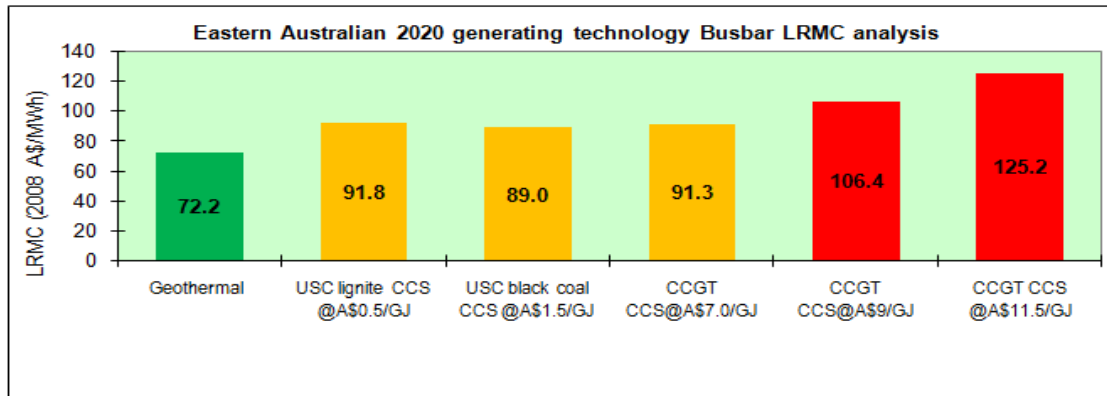
The long term supply costs of alternative baseload electricity supply options for eastern Australia are subject to a number of critical uncertainties, notably the future level and path of domestic gas prices the price of CO₂ following the introduction of an emissions trading scheme and the technical and commercial feasibility of carbon capture and storage applied at scale to fossil fuel plants. Geodynamics has therefore commissioned analysis to the impact of critical variables on the LRMC of competing alternatives to 2020.

The work, which is described in more detail in Annex 1, modelled the LRMC of new build base load gas, coal and nuclear generating plants in eastern Australia to 2020 across a plausible range of natural gas and CO₂ prices, assuming a 10% pre-tax IRR and 100% equity financing. The modelling reflects:

- State-of-the-art technology assumptions for generating plants:
 - For EGS this assumes “nth plant” (i.e. mature) geo-thermal base load electricity generation; plausible learning curves for drilling and completion costs; and commercially and competitively available above-ground generating plant technology.
- Current (2008) new build economics assumptions from industry participants.
- Current estimates of carbon capture, transport and storage costs.
- Natural gas price estimates using “triangulation” approach – long run marginal cost of supply, gas-on-coal competition and LNG export net-backs.
- CO₂ price range based on estimated international abatement portfolio costs

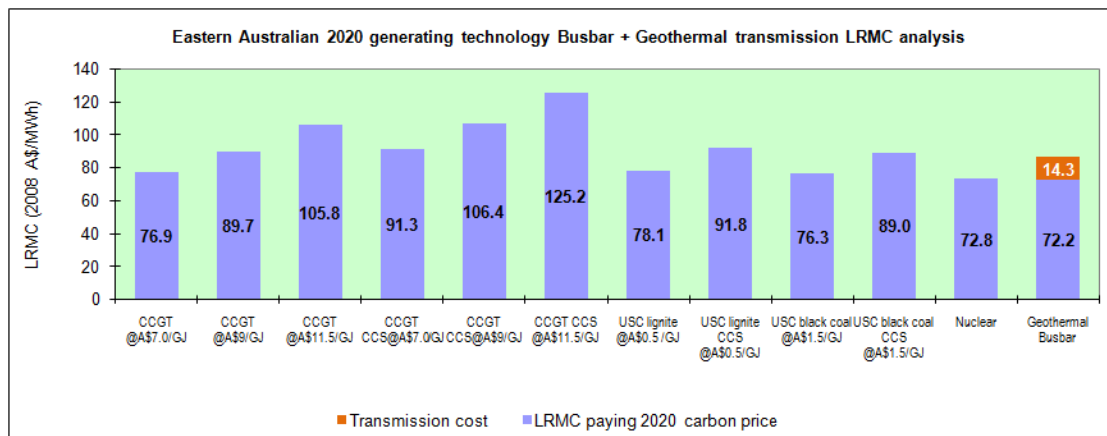
On these assumptions, the long run marginal cost at the busbar (i.e. excluding transmission costs) of “zero carbon” geothermal power from the Cooper Eromanga Basin in 2020 is expected to be A\$72/MWh (2008 real). By comparison, the busbar LRMC of advanced gas CCGT with carbon capture will vary from A\$91 – A\$125/MWh at gas prices of A\$7.00-A\$11.50/GJ; and the busbar LRMC of advanced black coal and lignite plants with carbon capture will vary from A\$89-A\$92/MWh (Figure 3).

Figure 3: LRMC busbar costs for baseload generation



Allowing for geothermal power carrying the full transmission costs for a new 600km 1000MW, 800KV direct current transmission line from Innamincka to the South Australian NEMCO grid (A\$14/MWh), it remains competitive with all low carbon base-load alternatives other than nuclear (Figure 4).

Figure 4: LRMC of geothermal with transmission costs



3. Spillover Effects and Option Value of EGS Electricity Supply

a. Knowledge development and transfer

The development of commercial scale EGS electricity supply involves building on and extending existing technology and knowhow, much of which has been developed by Geodynamics and its collaborators. As such it involves significant but tractable levels of risk that can be expected to be resolved over the period to 2011 with the deployment of both pilot plant (1MWe) and the first commercial scale demonstration plant (50Mwe) if the current important commercial barriers to the first 50Mwe plant can be overcome.

Geodynamics has already invested some A\$150 million to date in drilling three wells to depths exceeding 4 kilometres into the hot granite basement rocks in the Cooper Eromanga Basin. Key breakthroughs achieved include:

- Demonstrating the size of the resource -the large bodies of granite have been clearly delineated and proven to exist through drilling;

- Demonstrating the quality and potential of the resource - temperatures have been measured up to 250 degrees Centigrade
- Developing the world's largest enhanced underground heat exchanger and successfully producing the first hot fluids to the surface.
- Enhanced understanding of and capabilities in drilling at depth in hard rock, high temperature environments.

Geodynamics is sharing the results of its EGS development efforts with researchers from China, India, USA, Mexico, Switzerland, Germany, Poland, France and New Zealand (see Annex 2 for details). Some of this collaborative work can be expected to generate commercial benefits for Geodynamics but much of it is being transferred into the wider EGS practitioner community in Australia and overseas.

This knowledge transfer will continue as remaining key risks to be resolved are addressed in development of the next 9-11 wells that, subject to financing, will complete the first 50 Mwe commercial scale demonstration unit, viz:

- ability to stimulate multiple depth zones in a single well.
- ability to control circulation in multiple stimulated zones in a single well.
- development of improved down-hole monitoring tools to manage the high temperature reservoir.

The drilling out of the initial production wells will help establish the technical capability to allow rapid deployment of further generating capacity for Geodynamics and the increasing number of other players in the EGS field in Australia. In particular, this can be expected to promote industry capability development in drilling technology, reservoir mapping and stimulation and fluid handling and heat exchange design/management.

b. EGS – a zero carbon electricity, low risk electricity supply option for Australia

As shown in Section 2, rising oil and gas prices, the emergence of carbon emission pricing post 2010 and the expected costs of large scale power plant carbon capture and sequestration can be expected to change the economics of competing electricity generation technologies over the next decade.

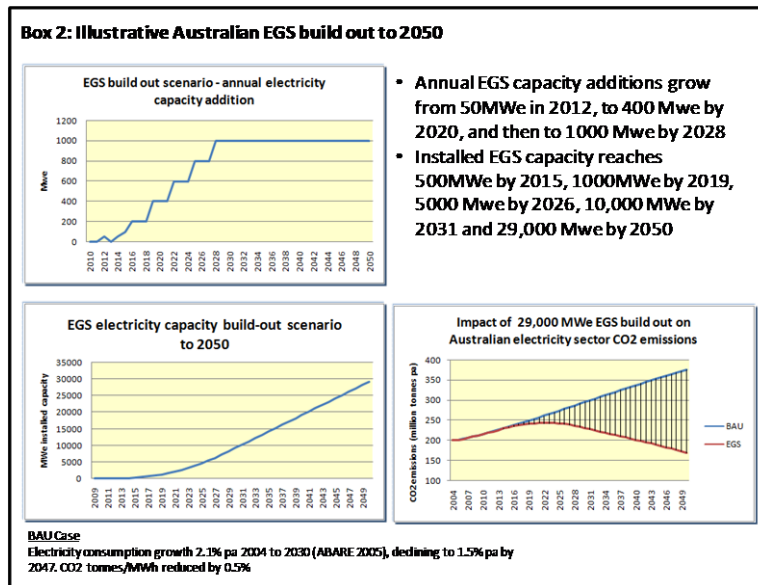
Near term geothermal investment provides the basis for both domestic and overseas electricity supply to transit to much lower carbon emissions at lower risk than fossil fuels or nuclear. This is because Government can have greater confidence in long term base load geothermal electricity costs by 2012-14 as the key geothermal reserve risks can be resolved with current technology.

By comparison, the practicality and economics of large scale carbon capture require new technology and will not be resolved until much closer to 2020. Uncertainty about public acceptance of a nuclear future for Australian electricity generation will likely only be resolved when the economics of carbon capture and sequestration are clear. Oil and gas price uncertainty will remain a permanent feature of energy economics.

A national energy strategy that ignores early investment in geothermal base load also exposes Australia to the risk of very high cost gas fired power generation in the event that large scale carbon capture and storage is economically delayed.

In summary, therefore, EGS is the lowest cost generation option offering a low emissions path compared with advanced coal and gas fired generation options using as yet unproven large scale carbon capture.

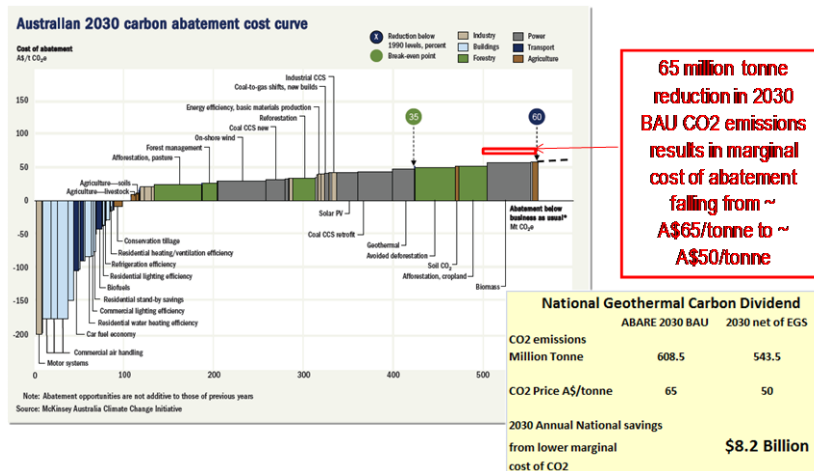
An aggressive but feasible build out of EGS energy capacity in Australia of 29,000 MWe by 2050 could reduce the business as usual (BAU) Australian electricity sector CO2 emissions by 205 million tonnes per year in 2050, a cumulative reduction of 3.2 billion tonnes of CO2 compared with BAU (see Box 2).



In addition to offering lower cost, zero emissions electricity to eastern Australia, a successful early demonstration of the economics of geothermal power would reduce the expected marginal cost of carbon emissions for the entire Australian economy by shifting down long term expectations for stationary CO2 emissions.

Analysis based on the 2030 CO2 cost abatement curve recently published by McKinsey for Australia suggests that that a 65 million tonne reduction in demand for CO2 abatement permits in 2030 has the potential to reduce the market clearing price of abatement by ~A\$15/tonne across 543 million permits, resulting in national annual savings in 2030 of A\$8.2 billion (Figure 5). The NPV (2008 real @8%) of national savings from reductions in the marginal cost of CO2 abatement from large scale EGS deployment in Australia from 2020 to 2030 could exceed A\$13 billion.

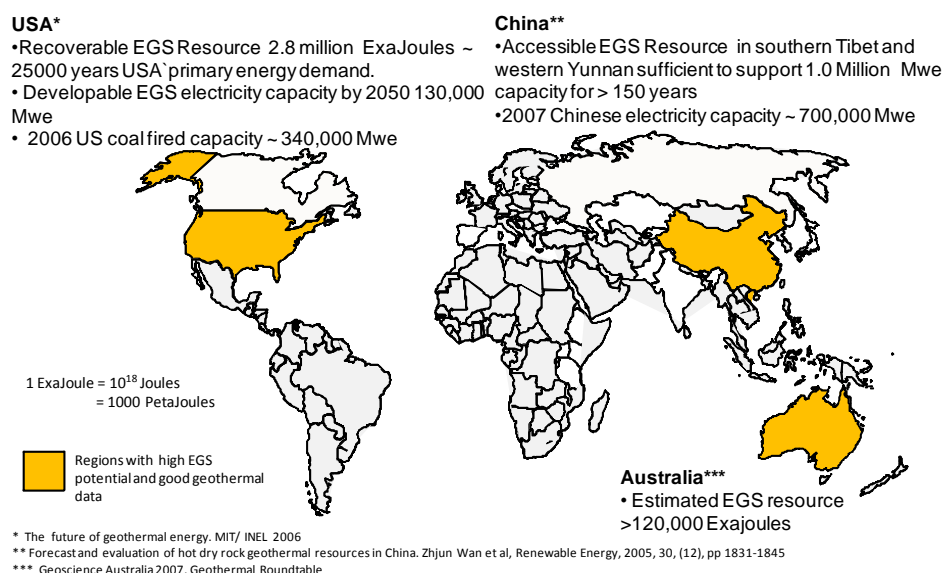
Figure 5: EGS impact on marginal cost of abatement



c. Global EGS opportunities

EGS development internationally has the potential for major displacement of coal fired electricity by zero emission base load electricity by 2050. For example, in the USA there is a potential to build out some 130,000Mwe by 2050, compared with a total installed capacity of in 2006 of 340,000Mwe. The potential is even larger for China which is currently set to become the largest global emitter of carbon (Figure 6).

Figure 6: EGS electricity capacity potential in USA and China



4. Market and Regulatory Barriers to Geothermal Baseload Supply

The remaining barriers to commercialisation of EGS in the Cooper Basin do not involve path breaking technological breakthroughs of the type already delivered by Geodynamics R&D effort to date. Instead they arise from the interaction of:

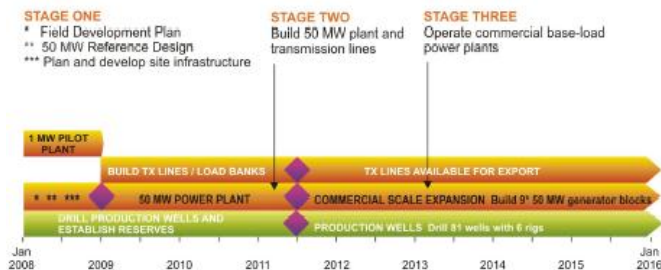
- the gap between early plant economics and equity/debt markets appetite for risk/reward (the “valley of death” problem discussed in the R&D Issues Paper); and
- the current regulatory arrangements governing the provision of transmission infrastructure that disadvantages new entrants, particularly in remote locations.

This section describes these barriers in more detail and suggests options for addressing them.

a. Pathway to mature plant economics

The pathway to mature EGS plant economics requires a build out to some 400-500Mwe over the period 2011-2016 (Figure 7). The initial 50Mwe demonstration plant (involving the drilling of 9-11 wells) is critical to both resolving remaining technical issues and establishing an initial cashflow from electricity sales that will establish EGS with capital markets as a viable baseload supply option.

Figure 7: Time path to mature plant economics

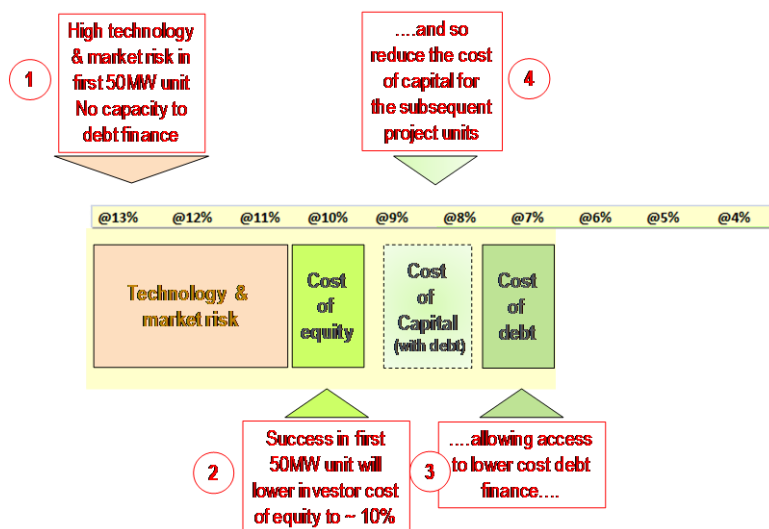


b. Closing the gap between capital market risk appetite and new entrant economics

Investors considering investment in new commercial scale EGS business confront a range of critical risks that are not present with established utility investments. These investments typically attract a high level of leveraging (debt/equity ratios of 60/40-70/30) associated with mature technologies, ready access to markets (via already established transmission networks) and hence predictable and stable cash flows.

For EGS, though remaining technological barriers are tractable, they interact with market and price uncertainty to generate a market cost of capital that renders the initial commercial scale investment uneconomic (Figure 8).

Figure 8: Gap between new entrant and mature cost of capital for utility investments

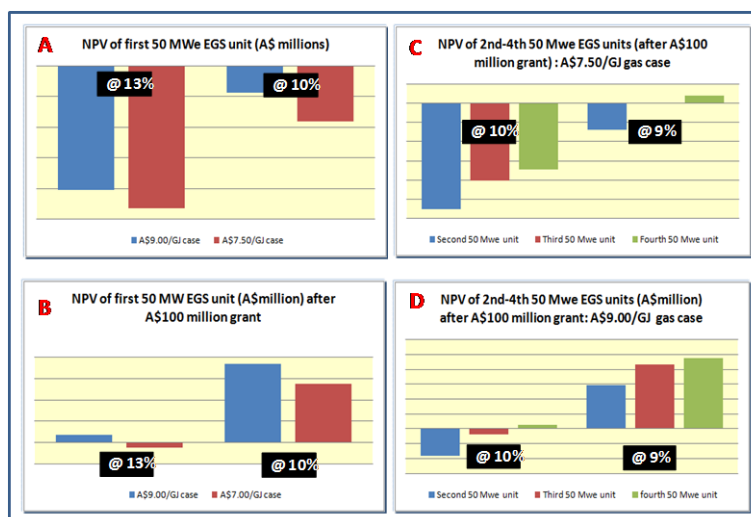


The practical implications of this for a Cooper Basin investment are illustrated graphically in Figure 9 for two different gas prices. Technical risk in first 50MWe unit is critical barrier to private sector investment. There is no private investor incentive to fund the first 50MWe EGS unit due to high technical risk (even in the high gas price case) – NPVs are negative for plausible costs of capital (graph A). Compare this with graph B which assumes the application of a A\$100 million grant that results in a breakeven NPV for the first 50 Mwe EGS unit, despite technical risk. The effect of the government investment is to lever in private equity investment of A\$250 million (a ratio of 2.5:1).

The second round impact of the government grant on the impacts for units 2-4 is even more pronounced (graphs C and D for different gas prices). With reduction in technical risk after first 50 Mwe unit, access to debt finance at 9-10% makes subsequent investments possible even in the low “price” scenario.

Private equity investment in this case totals A\$1.3 billion at completion of unit 4, a government multiplier impact of 13:1

Figure 9: Risk reduction and leverage effect of government assistance



c. Provision of transmission infrastructure

The current regulatory arrangements governing the augmentation of the transmission network in eastern Australia effectively require new entrant generators to pay for all the costs associated with connecting into the transmission network. This contrasts with earlier arrangements under which much of the legacy transmission assets have been built where the costs were distributed across all electricity customers and/or taxpayers.

The current arrangements exacerbate the capital markets risk problem for new technologies referred to above by increasing the capital costs of entry. As such, they are ill suited to facilitating low/zero carbon supply options. The problem is particularly marked in relation to geothermal energy production in the Cooper Basin because of the large distance from any major load centre in the Australian National Electricity Market (NEM). This requires extensive transmission infrastructure to be built to enable the delivery of the zero emission energy into the grid.

One option would be to build small capacity lines to match the generation output (say 50MW) and duplicate them each time a new generation plant comes on line. This is probably the cheapest option for an individual 50MW unit in isolation, but is sub-optimal when taking a holistic view of the resource and transmission requirements over the longer term (see below).

The most cost effective option in the long term would be to build a foundation transmission network that is able to commence operation with low output from the region but can be scaled up incrementally to be fully utilised over time (i.e. start with 50MW but be able to ramp up on the same infrastructure to 1,000MW at minimal additional cost). This could be designed to address the emerging need to strengthen the already overloaded interconnections into the east coast electricity grid between South Australia (SA) and Victoria and New South Wales/Queensland. Such strengthening will be needed to facilitate the transfer of increasing amounts of wind power generation arising from the expanded MRET scheme that will mainly be located in SA and southern Victoria.

This second option is likely to be far more cost effective in the long term but would almost certainly not be built under existing arrangements: it will underutilised in the early years of its operation, as the power

stations are introduced incrementally, and hence not be able to meet capital market financing benchmarks. Hence, it would only be built with some form of government support.

This challenge reflects not only the relatively narrow economic framework within which this form of critical infrastructure is managed but also the absence of a national strategic framework for planning the transition to a low carbon energy supply for Australia. The current system of state based ownership and regulation is ill-suited to putting in place a network that facilitates supply from a range of potentially cost competitive zero carbon options that are relatively disadvantaged by distance from load centres. It is not clear that potentially ad hoc government intervention, for example, one off payments from the Renewable Energy Fund requiring 2:1 private/public sector contributions, will deliver an optimal outcome.

In a carbon constrained world, there would appear to be a strong case for government funded investment in strategic infrastructure critical to facilitate the emergence of competitive low carbon energy supply options. In principle, this would not only include electricity transmission but also gas and CO₂ transmission infrastructure.

5. Options for Addressing Market Failure

a. Allocating priorities and resources – framing considerations and proposed criteria

Fossil fuel based electricity currently forms the backbone of the Australian energy supply system. Its scale and form reflect both Australia's resource endowment of large amounts high quality coal and gas, coupled with a history of government investment decisions that have overwhelmingly favoured the creation of highly centralised, large scale electricity generation and long distance transmission networks.

Despite significant market reforms and the expansion of the Mandatory Energy Renewables Target to 20% by 2020, the current pattern of ownership, regulation and pricing in the industry continues to create formidable barriers to alternative, low/zero carbon supply options. In addition to the transmission issues mentioned in Section 4, this includes such things as: government ownership of major generators in certain jurisdictions that has favoured broader industry development objectives over commercial returns; underpricing of key inputs (like water); and large scale and persistent electricity subsidies for energy intense manufacturing.

Against this background, Geodynamics believes there is a compelling case for public support for the development and early commercialisation of low emissions technologies and that such assistance should be directed to projects that:

- Are demonstrably additional to what the proponent would have undertaken in the absence of the support – as measured by the gap between typical returns required by investors and the project with and without assistance.
- Demonstrate sufficient Australian resource to realistically supply a substantial proportion of Australia's energy needs over the period to 2050, with a preference for projects/technologies that can achieve cost effective build out at scale early – the metric could be expressed in Gwh deliverable by 2020, 2025, 2030 etc (as per the MRET target).
- Have a very low environmental impact overall (including both zero/very low emissions), and be sustainable in the long term in terms of the size of the resource and its ongoing environmental impacts – the metrics here would be both tonnes CO₂e avoided and air pollution, water draw/pollution, land/biodiversity impacts on a full cycle basis.

- Have a demonstrably realistic chance of commercialisation at scale domestically and internationally - metrics here would a minimum internal rate of return (post government assistance) commensurate with the appropriate risk profile and prevailing long term debt costs.
- Are capable of potentially leveraging a significant multiple of private sector funding – a minimum gearing ratio might be 1:1 but possibly differentiated according major classes of asset.

It is for consideration how CCS and other related fossil fuel emissions reducing technologies should be treated in relation to future government assistance for low emissions technologies. Clearly, coal-fired generation is currently is a major source of emissions that requires appropriate adjustment assistance to move to a carbon constrained future.

On the other hand, the Australian fossil fuel based electricity sector is a large mature sector with a turnover of \$36bn (ABS, 2005-6) but has so far the established domestic industry has only committed some \$100m a year since 2006 towards CCS and other low carbon technologies; it is already receiving substantial assistance from Federal and State Governments to support clean coal/CCS technologies; and it has received clear signals over a long period about the nature of the climate change problem and the likely role that carbon pricing would play (the first Australian National Greenhouse Strategy was published in 1992).

More importantly, the currently available evidence suggests that “clean coal” will still emit some 100-200ktonnes CO₂e/MWh. This begs the question what should constitute low emissions for the purposes of R&D/commercialisation support. The emerging evidence of the potential need for the acceleration and tightening of emissions reductions targets discussed in the Garnaut Review’s Interim Report suggests the need for a stringent definition to generate options capable of delivering more demanding targets.

b. Methods of assistance

Broadly, there are four possible ways of providing public financial support for the development and commercialisation of low emissions technology:

- Payments through the tax system (tax deductions or tax credits)
- Direct subsidies in the form of grants or loans
- Government equity investments
- Loan/financing guarantees

The first three methods involve a direct, immediate call on the public purse, while the fourth involves a contingent call on public funds (which would normally be counted as a liability for public expenditure control purposes). The cost of tax concessions tends to be open ended (as it is driven by the size of complying business spending) while the other forms can be limited by administrative or legislative fiat.

The bulk of Australian Government support for business expenditure on research and development (BERD) in recent years has been directed through the tax system (via the 125/175% R&D tax deductions), with the broad policy objective of increasing BERD on the basis of broad spillover benefits for the economy as a whole. The nature of the policy objective avoids the “picking winners” problem but at the risk of loss of additionality (i.e. there can be no assurance that the company would not have undertaken the R&D in the absence of the tax concession).

Both State and Federal Governments have also provided significant direct subsidies (usually on a sectoral basis). Loan guarantees and equity stakes have only tended to be used in very limited circumstances.

In principle, any of these methods can be configured to have the same impact from an investor risk/return point of view. Given the nature of the policy problem under consideration – the acceleration of development/commercialisation of low emissions technologies - support through the tax system would still need to be evaluated against selection criteria of the type suggested above. In large measure, therefore, the choice of mechanism is a second order issue which should be driven by considerations of transparency and ease of administration.

In general, Geodynamics favours a straightforward grant scheme with competitive qualification against the criteria suggested above. This would be simple to administer and would provide a clear incentive for private investors to control capital expenditure and manage technical risk. Government/societal carbon portfolio risk (arising from over concentration on one technological option) could be managed by ensuring a requisite degree of diversity constrained by the proposed selection criteria, including support for strategic transmission investments that facilitate development of competing low carbon energy supply solutions.

An alternative, modelled on export finance guarantee arrangements, would be the establishment of a specific purpose low emissions loan guarantee company wholly owned by government. This would provide for detailed decisions on the allocation of support to be taken within a more commercial culture at arm's length from government. An illustrative outline of how such an arrangement might be configured and managed is at Annex 3.

Annex 1: Approach and assumptions used for modelling of LRMC of alternative baseload supply

1. Establish the range of Long Run Marginal Costs of new build base load gas, coal and nuclear generating plants in eastern Australia to 2020 across a plausible range of natural gas and CO2 prices, assuming a 10% pre-tax IRR:
 - State-of-the-art technology assumptions for generating plants.
 - Current (2008) new build economics assumptions from industry participants.
 - Current estimates of carbon capture, transport and storage costs.
 - Natural gas price estimates using “triangulation” approach – long run marginal cost of supply, gas-on-coal competition and LNG export net-backs.
 - CO2 price range based on estimated international abatement portfolio costs
2. Establish the range of Long Run Marginal Costs of Cooper- Eromanga Basin “nth plant” geo-thermal base load electricity generation and transmission costs to the NEMCO grid in 2020., assuming a 10% per-tax IRR:
 - Plausible learning curve for drilling and completion costs.
 - Commercially and competitively available above-ground generating plant technology.
 - Include LRMC of new 600km high voltage current transmission link 800KV, 1000MW from Innaminka to Davenport (South Australian NEMCO grid)
 - Compare the risk profile of geo-thermal electricity generation, nuclear generation, and carbon capture and sequestration for fossil fuel fired generation.
3. Eastern Australian term-contract gas prices are expected to increase from current levels (~A\$3.50/GJ) to A\$7.00-A\$11.50/GJ by 2020 (2008 real) as a result of gas on coal competition in new power projects under CO2 emission constraints, and through the development of oil-to-gas price linkages in new coal bed methane based LNG export projects in Queensland.
4. Carbon emission prices are expected to be A\$35-A\$40/tonne CO2e in the period 2020-2030, based on comparisons of international carbon abatement cost curves.
5. Based on current costs, the long run marginal cost at the busbar of “zero carbon” geothermal power from the Cooper Eromanga Basin in 2020 is expected to be A\$72/MWh (2008 real).
6. By comparison, the busbar LRMC of advanced gas CCGT with carbon capture will vary from A\$91 – A\$125/GJ @ gas prices A\$7.00-A\$11.50/GJ, the busbar LRMC of advanced black coal and lignite plants with carbon capture will vary from A\$89-A\$92/MWh, and the LRMC of nuclear is expected to be ~A\$73/MWh.
7. If geothermal power carries the transmission cost penalty (A\$14/MWh) for a new 600km 1000MW, 800KV direct current transmission line from Innamincka to the South Australian NEMCO grid, it remains competitive with all low carbon base-load alternatives other than nuclear.

Annex 2: Geodynamics international cooperation on EGS development

Organisation	Timing	Area of Interest
Dept of Chemical Engineering, Massachusetts Institute of Technology	2006-2008	Collaboration on HFR research in Australia and USA
CRIEPI, Japan	2003-2008	Acoustic emission monitoring/HFR in general
Japex Research Centre	2003-2004	Acoustic emission analysis and reservoir analysis
Tohoku University	2001-2004	Acoustic emission research for HFR
University of Utah	2004-2008	Chemical tracer testing of geothermal systems
Soultz project, France	2002-2008	HFR specialist
Los Alamos project, New Mexico	2002-2004	HFR specialist
University of Auckland	2004-2008	World authority on geothermal scaling and corrosion
Sandia Laboratories, New Mexico	2006-2008	High temperature down hole logging
Indian Institute of Technology, Bombay	2004-2006	HFR in India, India's leading geothermal specialist
US Geological Survey	2007-2008	High temperature down hole logging
Swiss Federal Institute of Technology	2004-2008	Reservoir engineering specialist on HFR
Instituto de Investigaciones Eléctricas, Mexico	2004-2005	World authority on H ₂ O-CO ₂ -CH ₄ system
Geothermal Explorers Ltd, Switzerland	2006-2008	HFR in Switzerland, leading project in Basel.

Sinclair Knight Merz, Auckland	2007-2008	NZ geothermal resource and reserves expert
University of Auckland	2007-2008	Analysis and deployment of acoustic emission monitoring systems
National Institute of Advanced Industrial Science and Technology (AIST)	2004-2006	Japanese HFR expert (Hijiori project)
Institute of Geology & Geophysics, Chinese Academy of Sciences	2007-2008	Chinese geothermal expert
Chevron Technology Ventures LLC, Houston Texas	2006-2008	Chevron is world's largest geothermal company
Q-Con GmbH, Germany	2002-2008	HFR reservoir experts
Southern Methodist University, Dallas Texas	2005-2007	US geothermal resource expert
Swiss Federal Institute of Technology	2004-2008	World geothermal authority
Geothermex, Inc, California	2004-2008	World's largest geothermal consulting company
Polish Geological Institute, Poland	2006-2008	Leading HFR geothermal studies in Poland

Annex 3: Illustrative outline of Low Emission Guarantee Company (LEG Co)

LEG Co would be formed by the Federal Government. It would have a substantial balance sheet, funded by proceeds from the auctioning of permits to emit under a National Emission Trading Scheme (NETS) proposed by the Federal Government.

LEG Co funding would only be a proportion of the total proceeds from the auction process. It is envisaged that the balance would be used to satisfy energy intensive industry requirements and low income households.

LEG Co would then be in a position to provide commercial guarantees to lenders for specific unmanageable risks faced by them and the Low Emission project proponents. This would be similar to the structure of export credit guarantee agencies.

The eligibility of projects to receive LEG Co support would be subject to a number of strict criteria, viz projects :

- Are additional to what the proponent would have undertaken in the absence of the support – as measured by the gap between typical returns required by investors and the project with and without assistance.
- Demonstrate sufficient Australian resource to realistically supply a substantial proportion of Australia’s energy needs over the period to 2050, with preference for projects/technologies that can achieve cost effective build out at scale early – the metric could be expressed in Gwh (as per the MRET target).
- Have a very low environmental impact overall (including both zero/very low emissions), and be sustainable in the long term in terms of the size of the resource and its ongoing environmental impacts – the metrics here would be both tonnes CO2e avoided and air pollution, water draw/pollution, land/biodiversity impacts on a full cycle basis.
- Have a demonstrably realistic chance of commercialisation at scale domestically and internationally - metrics here would a minimum internal rate of return (post government assistance) commensurate with the risk profile.
- Are capable of potentially leveraging a significant multiple of private sector funding – a minimum gearing ratio might be 1:1 but possibly differentiated according major classes of asset.

Every project would be unique and the support provided by LEG Co would be different for each project depending on the various risks being faced, whether they involve low emissions technology directly or facilitating investments (such as transmission augmentation).

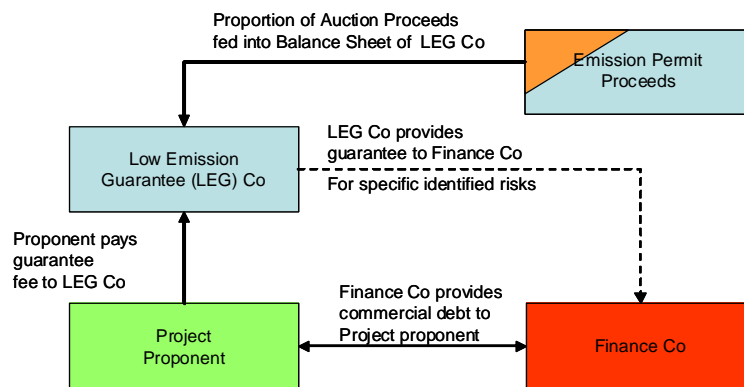
In these guarantee structures the project lenders (Finance Co below) will then be in a much better position to provide sufficient levels of debt at commercial rates as they are basically receiving a government guarantee for specific risks that are unable to be assumed by the lenders or the project proponents.

The project proponent will service the debt as normal with the lenders and will pay LEG Co a commercially based fee for providing the specific risk guarantee.

The effect of this structure is to support low emission generation proponents on the road to commercialisation without the need for direct government subsidy. Specific risks can be isolated and borne by the various parties to the project being the Proponent, Lender and LEG Co.

Proposed Scheme Mechanism

Each project will be unique and whilst there will be some similarities / crossovers in the risks being faced this is not a cookie cutter approach with standard agreements and terms. There will undoubtedly be a significant amount of time and effort to draw up these complex risk allocation guarantee structures, but it will lead to a more commercially focused arrangement and will drive significant commercial rigour into the development and negotiation of financing arrangements.



LEG Co would ultimately aim to be self financing, funding its guarantee liabilities through guarantee fees. However, LEG Co’s guarantee obligations would be backed by the Federal Government.

The size of the directly funded balance sheet (from the proceeds from the emissions trading scheme) would enable it to potentially leverage the amount of the project guarantees by some multiple and give it the ability to cope with the inevitable failure of a proportion of the projects.

For example, if the expected and actual failure rate was 1 in 5 and the balance sheet of LEG Co was funded by \$500 million of proceeds from the emissions trading scheme, LEG Co could expect to guarantee \$2.5 billion of project obligations before the Federal Government were required to fund any obligations.

Such mechanisms will allow traditional debt financing approaches to be used to fund projects of a renewable nature where the traditional lending criteria would not otherwise be met (i.e. technology certainty, revenue certainty, low risk, bankability) due to the risk characteristics of the project. This reduces the need for explicit government funding / support.