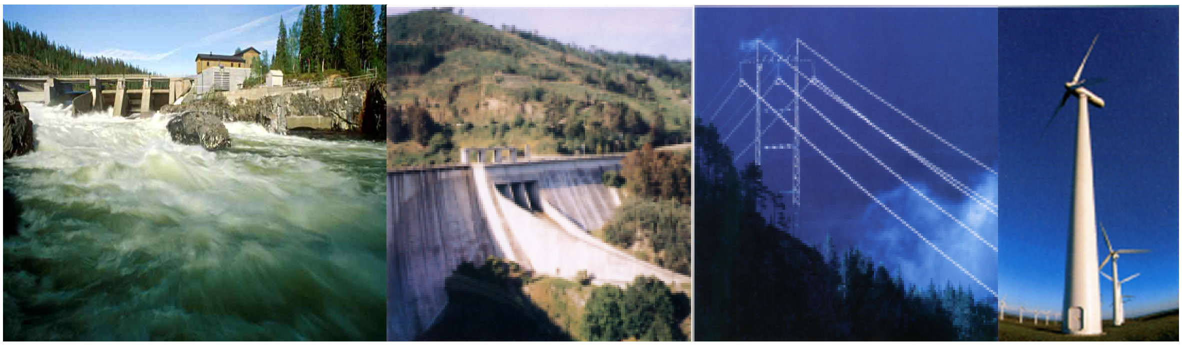
Regulatory Study to Encourage Energy Efficiency through Investment in Rehabilitation of Coal fired Generation Plant in India



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Energy Sector Management Assistance Program (ESMAP)

October 2008

IPA Energy + Water Consulting

KPMG

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LIST OF COMMON ABBREVIATIONS

ABT...................... Availability Based Tariff
AC .... Alternating Current
ADB .... Asian Development Bank
AG&SP .... Accelerated Generation and Supply Programme
AHP...................... Ash Handling Plant
ANSI .... American National Standard Institute
BHEL .... Bharat Heavy Electricals Limited
C&I....................... Control & Instrumentation
CEA...................... Central Electricity Authority
CAPEX................. Capital Expenditure
CDM..................... Clean Development Mechanism
CERC .... Central Electricity Regulatory Commission
CHP...................... Coal Handling Plant
CW .... Cooling Water
DC .... Direct Current
DERC .... Delhi Electricity Regulatory Commission
Discom .... Distribution Company
ERC……………...Electricity Regulatory Commission
EU .... European Union
EUR...................... Euro
FBA...................... Furnace Bottom Ash
FoR....................... Forum of Regulators
FSA .... Fuel Supply Agreement
GEF .... Global Environment Facility
Genco……………Generating Compnay
GHG..................... Greenhouse gases
GOI....................... Government of India
GT .... Gas Turbine
HFO...................... Heavy Fuel Oil
HHV..................... Higher Heating Value
HP......................... High Pressure
HR .... Heat Rate
IP .... Intermediate Pressure
IPP .... Independent Power Plant/Project
JV .... Joint venture
kWh...................... kilowatt hours
LE......................... Life extension
LHV .... Lower Heating Value
LIBOR.................. London Interbank Offered Rate
LP .... Low Pressure
MoP...................... Ministry of Power
MYT/MYTO........ Multi Year Tariff/Order
NEP .... National Electricity Plan
NPV...................... Net Present Value
NTPC .... National Thermal Power Corporation
O&M .... Operation & Maintenance
OEM..................... Original Equipment Manufacturer
OPEX .... Operation Expenditures
PC......................... Pulverised Coal
PF .... Pulverised Fuel
PFA .... Pulverised Fuel Ash

PFC....................... Power Finance Corporation
PiE........................ Partnership in Excellence
PLF.................Plant Load Factor
PPA .... Power Purchase Agreement
PPP .... Public Private Partnership
Rs .... Indian rupees
R&M .... Renovation and modernisation
RLA...................... Residual life assessment
SEB .... State Electricity Board
SERC.................... State Electricity Regulatory Commission
SHR .... Station Heat Rate
ST .... Steam Turbine
T/A .... Turbine Alternator
UPERC................. Uttar Pradesh Electricity Regulatory Commission
WB .... World Bank
WBERC................ West Bengal Electricity Regulatory Commission
YTD .... Year-to-date

Prefix Symbols and Multiples

P	-	pera	=	x 10^{15}
T	-	tera	=	x 10^{12}
G	-	giga	=	x 10^{9}
M	-	mega	=	x 10^{6}
k	-	kilo	=	x 10^{3}
h	-	hecto	=	x 10^{2}
da	-	deca	=	x 10
d	-	deci	=	x 10^{-1}
c	-	centi	=	x 10^{-2}
m	-	milli	=	x 10^{-3}
µ	-	micro	=	x 10^{-6}
n	-	nano	=	x 10^{-9}

Units

bar	-	bar = 10^{5} Pa (pressure)
cal	-	calorie (energy)
ºC	-	degree Centigrade (temperature)
h	-	hour (time)
Hz	-	Hertz (frequency)
K	-	kelvin (temperature)
kg	-	kilogram (mass)
J	-	Joule (energy)
m	-	metre (length)
N	-	Newton (force)
Pa	-	Pascal (pressure)
s	-	second (time)
t	-	tonne = 10^{3} kg (mass)
V	-	Volt (electrical potential)
VA	-	Volt Ampere (power)
W	-	Watt (power)
Wh	-	Watt hour (energy)

1. EXECUTIVE SUMMARY

- **Background**

The Indian power sector suffers from considerable supply shortages. The Government of India (GoI) is addressing this problem both through a major new build programme (including certain fiscal incentives for construction of larger and more efficient plant) and through rehabilitation (renovation and modernization or R&M as it is known in India) of existing coal fired plant. Around two-thirds of India's existing 65,000 MW of coal fired plant capacity is owned by State Government utilities, but much of this is reported to be in a poor condition, with low load factors and station heat rates of up to 4,000 kcal/kWh. Current R&M activity is not keeping pace with the requirements. R&M implementation has lagged significantly behind the requirements over the 10th plan period (2002-07), and during the current 11th plan period nearly 13,000 MW of R&M is targeted.

The GoI has taken several policy initiatives to support R&M activity. This is reflected in the Electricity Act 2003 and the National Tariff Policy (2006). The National Tariff Policy states that - *"Renovation and modernization (it shall not include periodic overhauls) for higher efficiency levels needs to be encouraged"*. The tariff policy goes on to advocate the use of a multi-year tariff framework that includes capital costs of rehabilitation and allows the sharing of these benefits. However, despite several policy and programme initiatives by the GoI, pace of R&M in India remains extremely slow. Clearly, there are a number of barriers affecting the rate of investment. The GoI has requested the World Bank and Global Environment Facility (GEF) to demonstrate the viability of energy efficient R&M practices in three coal-fired generation units across the states of Maharashtra, West Bengal and Haryana.

Within this context, this study has the objective of providing power sector regulators and other stakeholders in India with "a coherent understanding of regulatory options available to encourage investment in … energy efficient renovation and modernization (EE R&M) at the state level." The project also aims to develop workable regulatory solutions derived from a comprehensive understanding of the issues in India and, where relevant and appropriate, from international best practice.

- **Approach**

The Inception mission and discussions with stakeholders held during early and mid-December 2007 provided us insights from a range of stakeholders on the barriers and constraints to promotion of energy efficient R&M projects. These discussions and analysis are contained in Annex 4, and summarised in Section 2 of this report. A review of international experience that could apply to considerations in India is documented in Annex 7. Based on these, a range of potential options was developed and discussed with the project steering committee members[1]. These options were analysed and refined using a financial model and subsequently discussed in a Workshop[2] with a focussed group of senior representatives of regulators, utilities, generators and policy makers.

[1] This study was endorsed by the Indian Forum of Regulators and the steering committee for the study comprised Dr. Pramod Deo (whilst Chairman, Maharashtra Electricity Regulatory Commission now Chairman, Central Electricity Regulatory Commission), Mr. K. Venugopal (Member, Delhi Electricity Regulatory Commission), Mr. Vijoy Kumar (Chairman, Uttar Pradesh Electricity Regulatory Commission), Mr.S.Kujur (Chairman, Jharkhand Electricity Regulatory Commission) and Mr.S.N.Ghosh (Chairman, West Bengal Electricity Regulatory Commission).

[2] Workshop entitled "Regulatory incentives for investing in renovation & modernization of coal-fired generating plants focusing on energy efficiency" Friday 2nd May 2008, The Claridges Hotel, New Delhi. List of attendees is provided in Annex 9.

The diverse contexts in different Indian states, combined with the different pace of power market development, necessitated that this study identify a range of options suitable for different conditions. The various options identified are not mutually exclusive. The options developed in this report can co-exist as it is expected that Regulatory Commissions will use various approaches, depending upon the status of the power market in their state and the readiness of the Discom and the Generator to absorb the risks and benefits inherent in our options.

This study has developed certain options, evaluated them against barriers & constraints, and identified the implementation prerequisites. However, regulators would need to undertake analysis of impact on power purchase price and other relevant factors, before adopting any of the options. Equally, given that over 80% of the generating capacity is still under cost-plus regulation, the regulatory approach towards these plants can significantly impact the evolution and growth of the power market.

- **Barriers & Constraints**

In order to provide a clear understanding of the constraints and barriers to EE Renovation and Modernization (R&M) projects in India, Annex 4 sets out in detail the existing legal provisions, policies and regulations. It also sets out the barriers that have been identified. The key ones have been identified as:

Barriers & Constraints within the regulatory framework

a) **Gaps in the present evaluation framework: following unbundling of electricity generation and distribution activities** the evaluation of the potential benefits and risks of R&M options tends to be focussed either on a simple engineering assessment, or, at best, it takes account of the overall financial impact on the Generating company. In practice, a significant portion of the overall economic benefit of R&M investments would actually accrue to the power purchasing entity (the distribution company) who may pass it on to end consumers. However, this benefit is not at present captured in the present project evaluation approach.

b) **Misalignment of risks and benefits in the existing cost-plus approach:** as indicated above, R&M investments can be expected to provide substantial benefits to discoms (and their consumers)[3]. However, responsibility for R&M investment decisions and efficient operation rests with the generating company. Thus, the risks and benefits associated with inefficient decisions and operations are unevenly divided between generating companies and discoms and projects that are economically viable overall may not seem so attractive to an individual genco decision maker.

Barriers & Constraints beyond the regulatory framework

a) **Power market situation:** the massive supply-demand gap in India poses significant challenges for R&M investments. New build investments, with their ability to add a larger quantum of capacity at one go tend to attract higher management attention. At the same time, the necessity for outages that would permit R&M works to be carried out would further aggravate energy shortages.

[3] We don't take a view here on the extent to which the prevailing regulatory framework may require the Discom to pass through benefits to consumers.

b) **Institutional capacity:** institutional capacity to conceptualise, develop and execute R&M projects, in the context of a generally low-risk orientation of state owned generating companies, also emerges as a significant barrier to R&M investment. This is reflected in other factors such as the absence of an agreeable risk sharing arrangement between generating company and R&M vendors and overall perceptions of a lack of R&M capability and/or interest amongst vendors in India.

- **Evolving power market context important for choice of regulatory mechanism**

At present returns for more than 80% of the generation capacity (which includes nearly all the capacity with potential for R&M) are determined by some variant of cost-plus regulation, whereas new capacity generally expects a more market based approach to determining returns. The situation however can also vary considerably from one State to another.

Given this diversity it was considered to be critical to arrive at a range of regulatory options that have the potential to fit varying circumstances, rather than prescribing a single “preferred” approach. This should enable regulators in different states to adopt the option that fits best with the power market context of their state and with the intended pace of power market development.

- **Range of options identified**

In Section 4 we therefore identify a number of approaches based on three broad approaches to regulation of R&M projects, ranging from the traditional Rate of Return model, to variants of Performance Based Regulation and to regulation of markets, rather than of prices. These are illustrated in Figure 1 below, whilst the key features of the different approaches are described below and summarised in Table 1.

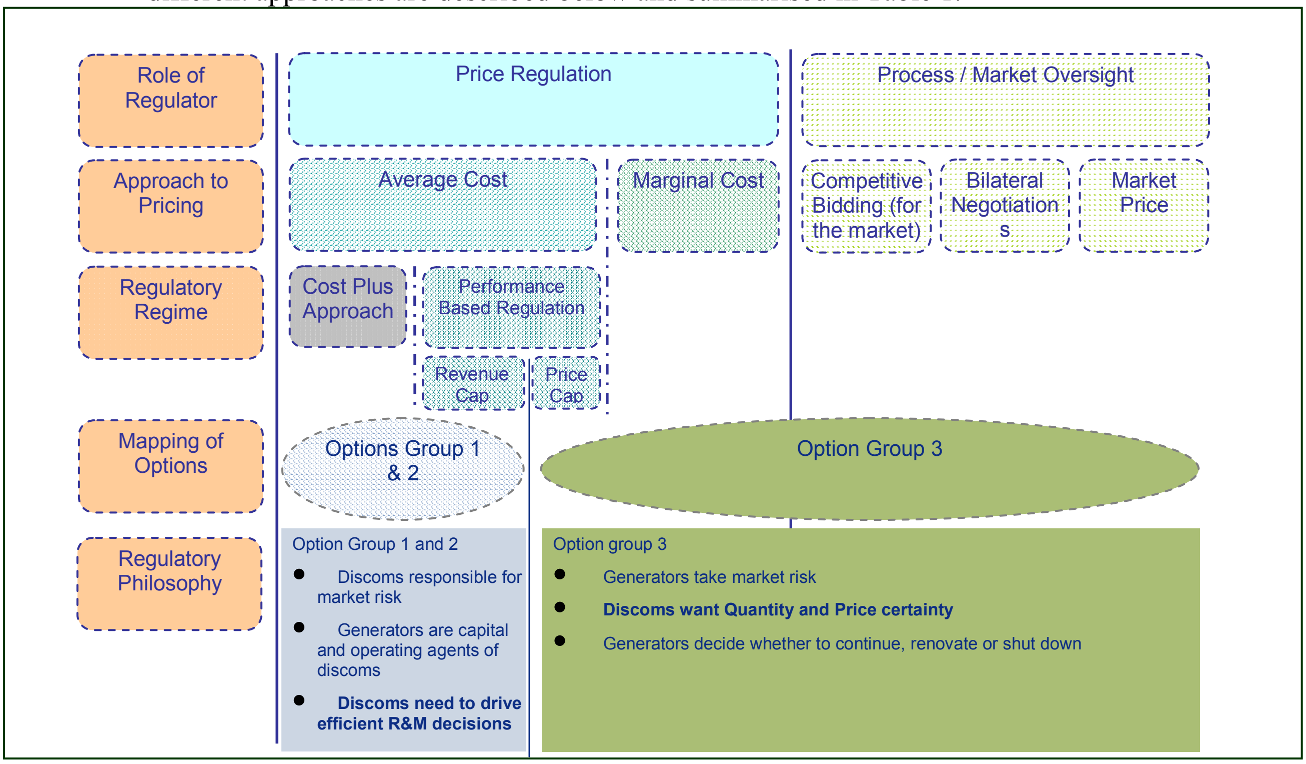

Figure 1 - Framework for selecting Options under different Regulatory Regime in incentivising efficient R&M decisions

The range of possible options that has been considered is: -

- **Option 1:** ***Modification of Traditional cost-plus approach*** This is a cost-plus approach, with allowable costs based on historic costs incurred. However, the R&M proposal is Discom driven. The Discom considers those R&M options which would fit with its least cost power procurement plan. The framework is similar to the existing regulatory framework except that a band of operating norms is set and the proposal is Discom driven, rather than Generator driven. If actual performance is within the band of norms the Generator may recover actual costs, but if it is worse than this band cost recovery is limited to normative levels
- **Option 2:** ***Advanced cost-plus option with price certainty over longer period*** This is an advanced cost-plus approach, based on Performance Based Regulation. The choice of R&M investment is made in the same way as in Option 1 i.e. the Discom proposes the investment only if it fits its least cost power procurement plan. However, there is price certainty over a longer control period, which could be set equivalent to the extended plant life. This price certainty allows for cost planning and profit retention for a longer period. The operating norms are thus set for the extended plant life.
- **Option 3:** ***Marginal cost based tariff determination for additional generation*** This option is distinct from options 1 and 2 in that the R&M investment decision does not involve the regulator and the Discom. In response to the pricing regime, the Generator would decide whether to renovate, continue or scrap the plant. The Generator is committed to supply only the equivalent of the pre-R&M quantity, at pre-R&M rates, for an agreed period. The price of the additional quantity supplied (whether through R&M or otherwise) is determined through marginal cost principles. There can be a number of variants of this option depending on the principle of marginal cost determination. This approach ranges from Performance Based Regulation (PBR) to market based contracting.

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Table 1 - Key Elements of Regulatory Approach under various Options

Key aspect of regulatory approach	Existing Approach (of SERCs)	Proposed Option 1	Proposed Option 2	Proposed Option 3
Investment decision process				
Origin of R&M Proposal	Developed by Genco	Discom develops R&M options as part of Least Cost Power Procurement plan. Genco develops alternative efficiency improvement proposals	Same as Option 1	Genco carries out assessment and takes decision to pursue R&M or not, depending on the marginal cost of the additional supplies
Approach for Viability assessment	Engineering approach. At best, Genco perspective (assesses costs and benefits to Genco)	Regulator to take Discom perspective (e.g. including cost of power purchase without R&M)	Regulator to take Discom perspective (e.g. including cost of power purchase without R&M)	Genco to assess based on marginal costs and tariffs. Regulatory approval not required. Tariff to reflect long run marginal cost of generation (cost of new entry) and not linked to actual costs of the plant
Tariff determinants				
Tariff philosophy	Cost plus	Cost plus. Reduced risk to generator compared with existing approach	Performance Based Regulation, with cost-plus building blocks. Increase return potential for generator compared with existing approach	Tariff to reflect long run marginal cost of generation (cost of new entry). Tariff not based on costs of the plant, nor dependent on whether R&M investment is made or not.

Key aspect of regulatory approach	Existing Approach (of SERCs)	Proposed Option 1	Proposed Option 2	Proposed Option 3
Capex included in tariffs	Actual	Actual	As approved ex-ante (no ex-post claw back)	Determination not required, as tariff/plant revenue is not based on the cost of the plant
Operating Parameters for tariff	Norms pre-set – don't distinguish between R&M or No R&M. Control Period 1 to 5 years	Actuals, within a normative band; to be reset at end of Control Period	Normative, trajectory set for the entire plant, for the Extended life (at least greater than Control Period)	Not required, since tariff/plant revenue is independent of specific cost of the plant
Return on Capital incorporated in tariff	Same as new build	Existing returns to continue	More attractive than new build/ continue (lower D/E; higher RoE)	Not required, since tariff/plant revenue is independent of specific cost of the plant
Supply and offtake commitments	Generator is responsible for actual generation and Discom is committed to the extent of actual generation.	Generator is responsible for actual generation and Discom is committed to the actual generation.	Generator is responsible for actual generation and Discom is committed to the actual generation.	Generator has the contractual commitment to supply pre-agreed quantities (or face penalties for non-delivery) and the Discom has to off take the pre-agreed contracted volume.
Tariff Structure	Two part, plus incentive	Two part, plus incentive	Two part, plus incentive, plus UI regime	Single part for committed supply

While these options address the regulatory barriers to different degrees (as evaluated below), we also developed a number of variations, to facilitate private sector participation, as one of the means to address the institutional capacity barrier. These are:

Option 2B: IPP type model – The regulatory approach is the same as for option 2 described above (i.e. driven by the distribution company). However, the private sector participant and tariff is determined through a competitive bidding process, and the private sector participant is required to enter into a bundled R&M and O&M contract for a long term, over which period the investment is to be recouped through the committed tariff.

Option 3B2: Generation franchise model – The plant is franchised to a private sector investor/operator for a pre-determined time period (by the generator), along with a Power Purchase Agreement, with certain committed supplies at a predetermined price, and additional supplies at a price to be determined through competitive bidding. The PPA commitments may not necessarily be serviced through the specific plant. Thus, the private sector participant is encouraged to determine the most appropriate action for the plant (continue, scrap, renovate, etc).

Some of the implementation prerequisites for various options are discussed in Section 4.2

- **Evaluation of options**

In Section 6, we evaluate these options against the barriers and constraints identified in Section 2 and in Annex 4. Using a high level financial model, we show that benefit sharing between the generator and discom is better balanced under option 2 and option 3. With option 1 the benefits lie largely with the discom, thus requiring the active involvement of the discom in the R&M decision making process. This is illustrated in Figure 2 below.

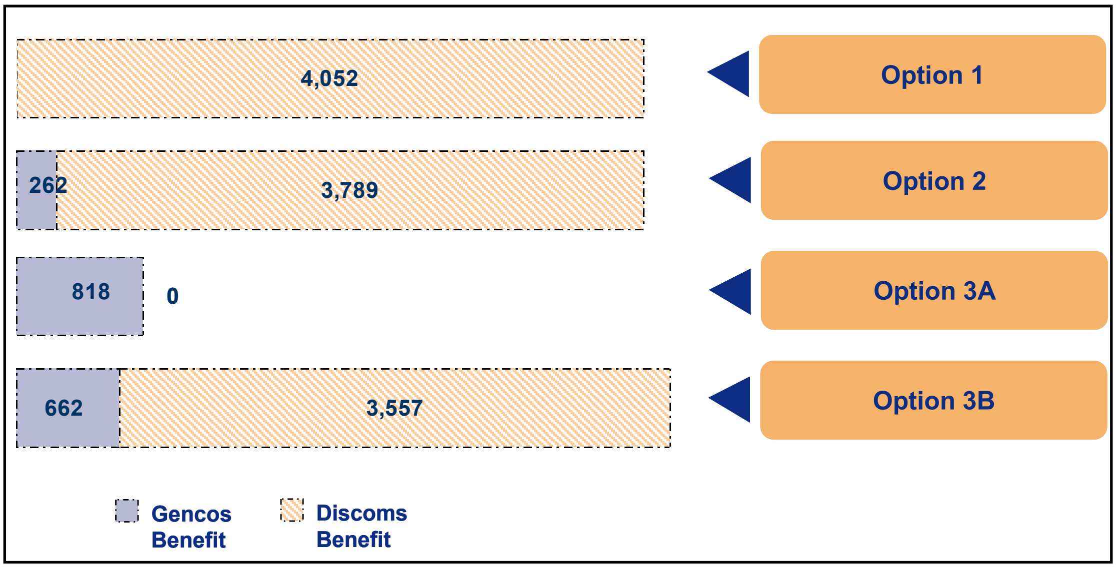


Figure 2 - Cost Benefit Analysis of the selected Options

Option 3B is described in detail in Section 5 and differs from Option 3 in that it requires the generator to continue to sell a base quantity of power at the present regulated tariff, with the additional quantity that can be generated post R&M priced at marginal cost.

Each of the three options improves the responsibility – risk sharing alignment, compared to the present regime. In case of option 1, the responsibility and risks shift somewhat towards the discom, improving over the current alignment. In option 3, they shift substantially towards the generating company, providing strong incentives for appropriate choice to be made. In option 2, investment responsibility and risk is aligned towards the Discom, while the operating responsibility and risk is aligned towards the generating company. This is illustrated in figure 3 below.

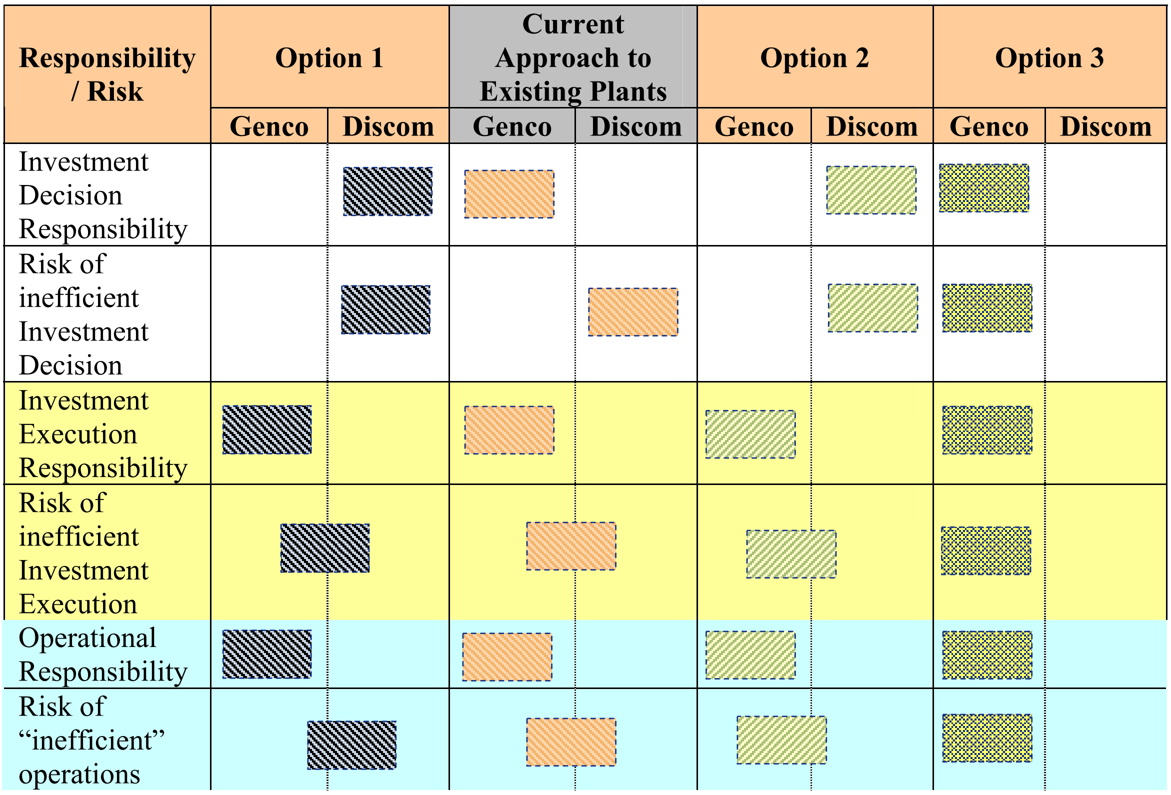


Figure 3 - Risk - Responsibility Sharing under various Options

In Figure 3 Option 1 is shown to the left of the current approach, in order to emphasise that it is a step backwards from moving to a market based approach and is a purer cost-plus regime. The current approach has started incorporating elements of Performance Based Regulation and completing that process would lead to Option 2. However, it is important to note that the current approach, which can be said to represent a transition between option 1 and option 2, has a lower degree of alignment than any of the three broad options we have developed.

Options 1 and 2 require the discom to play a significant role in the investment decision. Of course, this will need to be formalised through regulatory processes for least cost planning and investment approval. The approach to such dialogue, its focus areas, the technical issues involved and frameworks to support decision making, are illustrated in Annex 3, extracted from the detailed discussion in Annex 4

- **Conclusions**

As indicated above, given the diverse contexts and pace of market development in Indian states it was necessary for this study to identify a range of options. The options described are not mutually exclusive but coexist and Regulatory Commissions will be able to use the approach that best meets their circumstances.

This study has evaluated the options against key barriers & constraints and identified a number of implementation prerequisites. However, regulators should undertake their own analysis of the likely impacts on power purchase price and other relevant factors, before adopting any option.. Such further analysis (specific for each state) will show the need for a calibrated path for transition in the power market and the role of existing power plants in this process.

Having identified the barriers in a sharper focused manner and developed the framework for addressing them, a logical next step would be to implement one or more of the options as demonstration pilots in select states and to use this work to identify the detailed implementation needs. Because a key finding of this study is that gaps in institutional capacity are also a strong barrier to efficient choices, pilots based on Private Sector Participation models could play an important role, serving to demonstrate the potential upsides of R&M choices and helping to address the risk perceptions surrounding such investments.

2. INTRODUCTION

The Indian power sector suffers from considerable supply shortages. The Government of India (GoI) is addressing this problem both through a major new build programme (including certain fiscal incentives for construction of larger and more efficient plant) and through rehabilitation (renovation and modernization or R&M as it is known in India) of existing coal fired plant. Around two-thirds of India's existing 65,000 MW of coal fired plant capacity is owned by State Government utilities, but much of this is reported to be in a poor condition, with low load factors and station heat rates of up to 4,000 kcal/kWh. Current R&M activity is not keeping pace with the requirements. R&M implementation has lagged significantly behind the requirements over the 10^{th} plan period (2002-07), and during the current 11^{th} plan period nearly 13,000 MW of R&M is targeted.

The GoI has taken several policy initiatives to support R&M activity. This is reflected in the Electricity Act 2003 and the National Tariff Policy (2006). The National Tariff Policy states that - *"Renovation and modernization (it shall not include periodic overhauls) for higher efficiency levels needs to be encouraged"*. The tariff policy goes on to advocate the use of a multi-year tariff framework that includes capital costs of rehabilitation and allows the sharing of these benefits. However, despite several policy and programme initiatives by the GoI, pace of R&M in India remains extremely slow. Clearly, there are a number of barriers affecting the rate of investment. The GoI has requested the World Bank and Global Environment Facility (GEF) to demonstrate the viability of energy efficient R&M practices in three coal-fired generation units across the states of Maharashtra, West Bengal and Haryana.

This report develops a number of options and recommendations for incorporation in the existing regulatory and market framework. It also combines the analysis set out in Annexes 4 and 5, covering, respectively:

- the existing legal provisions, policies and regulations and the constraints and barriers applicable to EE R&M projects in India; and
- the somewhat limited range of international practice in the sphere of energy policy, with specific regard to the incentivisation of energy efficiency and the rehabilitation of coal fired generating plant.

Specifically:

- Section 2 sets out the context of the study;
- Section 3 summarises the constraints and barriers to energy efficient R&M in India, which are set out in further detail in Annex 4;
- Section 4 provides a framework for the main options identified, given present state of the Indian Power Market and describes the key lessons from our review of international best practice, which are described in Annex 5;
- Section 5 identifies the various options considered for this study;
- Section 6 analyses the various options identified in terms of their effectiveness in addressing the barriers and constraints identified in Section 3; and
- Section 7 sets out our conclusions and recommendations for a regulatory framework that can more effectively support energy efficient R&M in India.

2.1. Context of Study

The identification of our series of regulatory options and their evaluation, is based on the following broad premises:

- that there is a fairly large population of existing generating plant whose operating characteristics are significantly poorer than the expected benchmark. (According to Central Electricity Authority (CEA)[4], the potential for R&M for units with more than 15 years of operation is around 25,000 MW and possibly as much as 30,000 MW, mainly in 210 MW and 500 MW units);
- that there is a range of possibilities for improving operational efficiency, such as improvement in heat rate, decrease in auxiliary consumption, increase in plant output, extension of plant life, or some combination of these, which may be achieved through operational improvement only (relatively low investment) or through significant investment in R&M;
- that different options would be economically viable for different plant; and
- that economically attractive R&M investment options are not being implemented, at present, as a result of a series of barriers and constraints both within and external to the regulatory framework

Therefore, our objective was not only to devise a regulatory framework that would better incentivise R&M, but to devise a framework that would better facilitate adoption of the decision which is most appropriate and efficient in the circumstances, whether that was the adoption of R&M, a decision to scrap and replace, or even a decision to continue to "make do and mend."

2.2. Background – What EE R&M entails and existing incentives

This Section reviews:

- the overall need and scope for EE R&M projects;
- the type of projects and actions that can form part of an EE R&M programme;
- the requirement for enhanced O&M activities in order to ensure that the benefits of EE R&M are sustained;
- existing incentives for EE R&M.

Need and scope for EE R&M

At the present time Indian state generators are operating a range of plant at very low levels of efficiency, in many cases with heat rate values of 3000 - 4000 kcal/kWh and specific coal consumption of 0.8 kg/kWh, or even higher.

The CEA Performance Review of Thermal Power Stations for the year 2006/7 notes that the achieved heat rate for 56 thermal power stations, (38,611MW of

[4] Presentation on Energy Efficiency in Thermal Power Generation at Indo German Energy Forum - December 2007

capacity and more than 45% of 2005/6 peak demand) was 19.3% below the design heat rate. Average specific coal consumption was 0.715Kg/kWh.

In addition, the Expert Committee on Integrated Energy Policy has indicated the need for measures to increase the fuel conversion efficiency of coal-fired power plant owned by NTPC and State owned generating companies from an average of 30% to 35%.

With a comprehensive EE R&M project it should be possible to achieve heat rates at, or very close to design levels of efficiency. For example, with a 105MW capacity plant it might be expected that heat rate would improve, from around 3,300 kcal/kWh, to around 2,500 kcal/kWh, compared with around 2,900 kcal/kWh under a normal R&M project. This would lead to an improvement in specific coal consumption from around 0.80 to 0.62 kg/kWh and an increase in fuel conversion efficiency from around 25% to around 34%. Heat rate and enhancements to specific coal consumption would of course both depend critically on the quality of the coal available and whether the plant is operated and maintained optimally.

Against a background where India is suffering from significant power shortages/unmet demand, the benefits of comprehensive EE R&M projects alongside other measures to enhance load factor, life extension and improve R&M are clear. In summary EE R&M projects would help to:

- reduce fuel consumption and dependence upon imported coal through more efficient coal burn; and
- reduce the generation shortfall in the country through higher output levels.

Illustrative EE R&M schemes

We have assumed that EE R&M projects are those that deliver significant enhancements to the fuel conversion efficiency of a power station. This is normally expressed as station heat rate, in kcal/kWh, though it is important to bear in mind that the continued use of poor quality coals will have a detrimental impact on heat rate.

The greatest opportunity for EE R&M projects appears to be to undertake additional works in conjunction with life extension (LE) works. Works designed to significantly enhance unit HR may not be economically viable without LE, because LE provides an assurance that the plant will be expected to operate at a high plant load factor for a number of years.

Typical EE R&M works would however include the following:

- Full overhauls of the unit to original equipment manufacturer recommendations;
- Reduction of air ingress to condenser and fitting of on-load cleaning equipment;
- Renewal of airheater elements and seals;
- Renewal or repair of high pressure feed heaters;
- Ensuring the correct water quality for the boiler make in order to reduce boiler blowdown; and

- Reductions in leakage from passing valves

Other major works would include:

- Redesign of furnace and superheater heat transfer area to ensure design boiler pressures and temperature are achieved;
- Replacement of turbine modules with improved high efficiency blade design;
- Improved and increased milling plant capacity and burners to burn lower quality fuel;
- Renovation of control and instrumentation equipment; and
- Replacement of the furnace wall by membrane construction, including skin casing to reduce the air ingress and other modifications to fans to increase throughput.

Further details on potential heat rate improvements are set out in the Annex 5.

Sustaining the benefits through enhanced O& M methods

Effective O&M practices are essential in order to ensure optimization of the sustained performance of any asset, whether it is a new build plant or plant subject to an EE R&M proposal.

The assessment of O&M practices, skills and performance across the State Sector, is already supported by the Partnership in Excellence scheme and various other initiatives of the GOI, WB and others.

It should be noted that there are many well qualified, experienced and motivated staff in State Sector Gencos and it is likely that many improvements can be made if the right drive, ambition and performance framework can be established from senior management.

A way forward that complements our recommendations for a more active approach to asset management would be to provide a best practice framework, for example with checklists, that would enable each GenCo to perform an initial self audit (or to be audited by accredited and well qualified third parties. The objective would be to produce a gap analysis and detailed plans to move towards best practice, with subsequent sustained improvements in heat rate, availability etc. Monitoring mechanisms will also be critical to ensuring that performance enhancements are sustained.

Funding from PFC and agreement to approval of expenditure by State Regulators could be dependent upon agreement to a programme of O&M enhancements, including, but not necessarily limited to the establishment of:

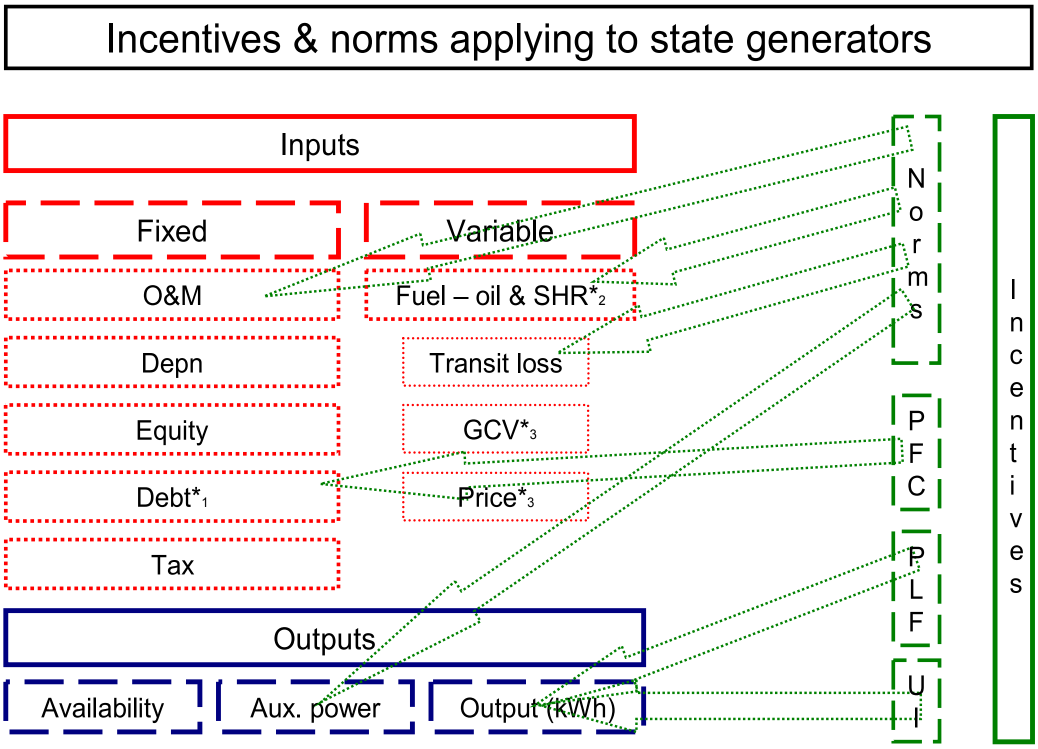
- clear O&M policies, principles and procedures
- clear objectives and targets and other key performance indicators
- implementation of appropriate monitoring mechanisms (and potentially to regulatory reporting requirements)

- optimum O&M organisation structures with the correct resources, skills and competence to deliver the objectives; third parties to be used where required and where economically viable
- robust 5 year Business Plans and detailed Annual Operating Plans and Budgets for each station.
- A detailed Asset Management Plan
- a proactive approach to Engineering Risk Management and Assessment
- a proactive approach to planned, preventative and breakdown maintenance
- the introduction of detailed Engineering Plant Status plans
- the introduction of best practice plant condition monitoring
- best practice evaluation of spares and stores holdings
- a proactive monitoring, auditing and review process

It is our assessment that such practices would not be expected to have a material impact on the GenCo's operating costs and they should therefore be given a high priority.

Existing incentives for R&M

The existing regulatory system in India is a complex one, consisting of a series of incentives and monitoring mechanisms and a variety of funding programmes. These are described in detail in Annex 4 but are also set out in Figure 4 below and summarised later in this section, for ease of reference. (UI payments are a disincentive for excess generation at certain times rather than an incentive, but are shown here for completeness).



Notes

1. Assumes generator is permitted to benefit from saving over assumed cost of debt
2. Input at unit/output from unit at assumed non-controllable GCV
3. Non-controllable items

Figure 4 – norms and incentives applicable to the state generating utilities in India

Norms

The National Tariff Policy stipulates that where a State owned/controlled company is the project developer, "regulators will need to resort to tariff determination based on norms." Norms are set out by the CERC in tariff regulations for central generators. State Regulatory Commissions must have regard to CERC guidance on norms but may adopt a different approach.

Although the cost plus approach used in India is typically an annual process, a number of states have issued, or are on the verge of issuing, multi year tariff orders. These are designed to create a framework with greater investment and regulatory certainty and to facilitate efficient expenditure through benefit sharing, during the applicable control period.

In India the multi-year tariff order works on the basis that the approved project cost and its financing plan form the basis for tariff determination. The allowed tariff is divided into two parts, fixed and variable.

- The fixed part comprises principally operation and maintenance (O&M) expenditure, depreciation, loan interest, taxation and a return on equity employed.
- The variable part (referred to as the energy charge) comprises the allowed fuel cost.

Costs are then categorised into controllable and uncontrollable costs, with generators responsible for controllable costs, which are recoverable on the basis of normative parameters fixed by the appropriate regulatory commission for the control period.

To the extent that efficiency levels are higher than assumed in the norms the generators receive the benefit of the assumed (but not incurred) cost recovery level for the length of the control period. To the extent that efficiency levels are lower than the assumed norms, generators are generally unable to recover revenue to cover the additional costs and the generator will need to make savings in the other elements of the cost base, or incur a loss.

Variations in uncontrollable costs, such as the gross calorific value (GCV) and price of fuel are permitted to be passed on to customers in the generator's tariffs. However the generator's use of fuel will be calculated on the basis of fixed operational benchmarks and not on the basis of actual use.

In the tariff order the CERC tightened the benchmarks for the period from 2004 to 2009 to 500MW units from 2500/kcal/kWh to 2450kcal/kWh, but left the benchmark for the smaller (and mostly older) 200/210 and 250MW units at 2500kcal/kWh. They also decided to set the same benchmark for old and new power stations.

In addition to energy cost benchmarks/norms, generators may also receive a plant load factor (PLF) incentive whereby the generator receives a flat rate payment for every unit generated in excess of the normative PLF. The PLF incentive set in the tariff regulations is 80% and the incentive for each additional unit is Rs 0.25kWh.

UI incentive

Because the PLF incentive gives a signal for excess generation, whether or not it is needed, some problems occurred with continued generation and there were resultant system frequency problems. As a result CERC introduced in 2002 an Availability Based Tariff (ABT) which levied an unscheduled interchange (UI) charge for generation at times of high system frequency. In effect the generator receives no payment for power (in excess of scheduled output) that is spilled on to the system at times of high frequency and is required to pay a penalty in the event that generation output is less than scheduled at a time of low system frequency..

Financial support from PFC

The MOP guidelines provide a framework that must be followed if generators are to benefit from subsidized debt financing from the Power Finance Corporation (PFC) which provides an interest rate subsidy of up to 3% (or 4% for projects in the North East).

In relation to LE the guidelines require Residual Life Assessment in the first instance. In relation to R&M, the guidelines indicate that the generator should prepare an R&M proposal and statement of benefits, including the introduction of best O&M practices, in association with a consultant (e.g. NTPC) and submit this to the CEA for clearance and to the PFC for sanction of a loan.

In many cases the objective of R&M schemes is to stabilize the plant and increase plant load factor to around 60%. To reduce the risks of the scheme adequate power to cover the shortfall in generation because of shut downs for the units (under RLA/R&M/LE) will be made available from the unallocated quota in the Central Pool

There appears to be no restriction on EE R&M schemes (designed to achieve performance at or near design heat rate) being supported by PFC subsidies. However, although such schemes would compliment RLA and LE projects and PLF focussed R&M schemes, as a result of the opportunity provided by an outage/shut-down, this does not appear to be required and therefore does not take place in an holistic and co-ordinated manner.

Conclusion

In practice EE R&M schemes would be expected to return a station to near design levels of efficiency. Because it would be expected to lead to performance beyond assumed/normative levels of efficiency, it would provide the generator with a strong incentive to carry out EE R&M works.

The MOP guidelines suggest that R&M and heat rate improvements should be considered, though they do not perhaps focus strongly on heat rate improvements at the present time. Nevertheless, we see no reason to assume that such investments would not be permitted by the relevant Regulatory Commission, providing that it felt that benefits would also flow to customers.

The indicative level of benefit attainable over and beyond existing norms is represented by typical savings in coal consumption of around 44,000 tonnes per annum for a 210MW LMZ unit running at a design heat rate of 2375 kcal/kg and burning reference quality coal, compared with the CERC norm of 2500 kcal/kg. This would equate to a financial saving of around $1.65m per annum, assuming a delivered coal cost of $37.50 per tonne.

For a unit of the same design, savings of around 74,000 tonnes of coal per annum would be made if lower quality coal, at around 2500kcal/kg was being burned. This would equate to a saving of around $2m per annum.

Details of these calculations are set out in Annex 5.

3. CONSTRAINTS & BARRIERS

A number of constraints and barriers have been identified in the existing framework that inhibit energy efficiency investment together with an initial range of solutions (set out in Annex 4 to this report). This Section categorises our further analysis of constraints and barriers on the basis of those factors that are clearly within the existing regulatory framework and those that can be described as beyond the regulatory framework.

3.1. Regulatory Framework

3.1.1. Gaps in evaluation framework, for efficient decision making

In the current regulatory framework, investment approval is a specific regulatory function. The typical steps in the process are:

- to identify the need for investment;
- to identify alternate ways to meet the identified need; and
- to evaluate the alternates in order to arrive at the optimum choice(s).

While the Electricity Regulatory Commission (ERC) will set required improvements in operating efficiency either for a single year, or for a multi-year period, based on a technical (engineering cost and benefit) analysis of present performance and of potential efficiency levels, this is not done in the context of an analysis of investment requirements, nor of an evaluation of alternate possibilities (low investment – low improvement; medium investment – medium improvement, etc). Rather, an EE R&M investment, if proposed by a Generating Company (Genco) is evaluated independent of other options.

In some states, there is also the added uncertainty of whether the required efficiency improvement will be further tightened following an approved R&M investment.

In addition, because least cost power procurement planning is done by distribution companies, the R&M possibilities for existing power plant owned by State Gencos are often not considered as an option in the present investment planning process.

Thus, it is our view that the framework for evaluation of the economic attractiveness of R&M proposals is often incomplete.

A number of possible evaluation approaches are illustrated in Figure 5 below and explained in the subsequent text.

S.No.	Particulars		Unit
Plant Assumptions			
1	Capacity		MW
2	R&M Investments		Rs. Crs.
3	Station Heat Rate		kcal / kWh
4	Plant Load Factor		%
5	Auxiliary Consumption		%
6	Residual Life		Years
7	**Generation**		**MU**
8	**Effective tariff (First Year)**		**Rs. / kWh**
Market Assumptions			
9	Short Term Power Purchase	Quantity	MUs
10		Rate (first year)	Rs. / kWh
11		Duration	Years
12	Long Term Power Purchase	Quantity	MUs
13		Rate (first year)	Rs. / kWh
14		Duration	Years
15	**Total Energy (7+9+12)**		**MU**
16	**Total Years**		**Years**

Engineering Cost

Financial Evaluation

Economic Evaluation

Figure 5 - Different Evaluation Approaches for Cost Benefit Analysis of R&M Investments

Engineering / Cost Evaluation: In the past, State Electricity Boards (SEBs) provided an engineering based justification (in terms of Rs Crs. investment per MW of capacity being renovated) for R&M projects. The Central Electricity Regulatory Commission (CERC) also appears to have relied on this approach in granting approvals to R&M projects, for example for the Tanda & Talcher thermal stations. However, this approach considers only the costs of R&M and the operating efficiency benefits that may be achieved and does not compare these with the full economic benefits (including the power purchasing costs of the Discom). As a result there is a strong risk that projects that may be attractive on a full economic benefit basis may not be actively pursued.

Financial Evaluation from Generator's Perspective: CERC and State Electricity Regulatory Commissions (SERCs) have indicated the use of this approach for evaluating proposed R&M works. Although it is perhaps more complete than an engineering based assessment, again, the evaluation of costs and benefits from the project focus on the benefits to the Generator and not the full economic benefits of the project. Costs are essentially the cost of capital invested in R&M, whereas benefits result from increased generation (improved Plant Load Factor (PLF) any life extension resulting from the project and reductions in variable costs (through improved Station Heat Rate (SHR). The project is positive if such benefits outweigh costs i.e. the Net Present Value (NPV) of the project is positive. This approach does compare the total costs and benefits of the plant but it fails to recognize the cost of not doing R&M (such as higher power purchasing costs that will be incurred if the project is not pursued and the Discom must buy additional power on the open market.

Economic Evaluation from Discom/Consumer's Perspective: Some State Regulatory Commissions have notified power procurement guidelines that require Discoms to procure power on the basis of least cost and merit order principles. The

Discom, while seeking approval of their power procurement plan from the Regulator, is required to demonstrate that it has evaluated all feasible options for meeting its energy requirement and that its plan represents the least cost option. If the Discom was to evaluate R&M options as part of this exercise, the economic attractiveness of R&M options would be compared with alternates such as new build. The evaluation would therefore include the additional costs of short term purchases during a plant shutdown for R&M, as well as revenue foregone because of un-served energy during the construction period of a new build plant. Such an approach would allow for a more complete evaluation of R&M investment possibilities and should lead to more efficient choices.

3.1.2. Misalignment of Risks & Benefits sharing in the existing Cost Plus Approach

The sharing of risks and benefits between a Generator and a Discom in the existing cost plus approach is discussed in detail in Annex 1 of this report. This shows that:

- While the investment is made by the generator, the benefits are heavily tilted in favor of the Discom. Conversely, the "cost" of not making R&M investments where economically feasible, is also borne by the Discom.

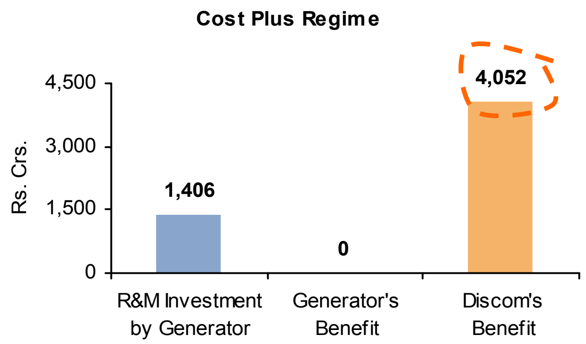


Figure 6 - Cost Benefit Analysis of R&M Investments in a Cost Plus Regime

- Also, while the responsibility for investment planning, execution and plant operation rest with the Genco, the risk associated with inefficiency in these is borne by the Discom.

Table 2 - Misalignment of Risk and Responsibility between Genco and Discom in Cost Plus Regime

Responsibility - Risk	Genco	Discom	Remarks
Investment Decision Responsibility			• Power procurement planning does not consider R&M options – Discoms have little say in R&M possibilities, until proposed by Genco • Inefficient choice (including not doing R&M which is viable) will impact power purchase cost of Discom
Risk of inefficient Investment Decision			
Investment Execution Responsibility			• Mix of ex-post and ex-ante approval of costs • Cost variations can be passed through if approved • Time delays would largely impact Discom
Risk of inefficient Investment Execution			
Operational Responsibility			• Uncertainty on improvement trajectory in some states – being addressed in others • Improvement trajectory not linked to investment requirement • Risk of variations in heat rate and auxiliary consumption borne by Genco within Control period, and by Discom beyond Control period • Risk of variation in availability borne partly by Genco, and substantially by Discom
Risk of "inefficient" operations			

Our detailed quantitative analysis of benefit sharing between the Generator and the Discom is provided in Annex 2 to this report.

In summary the cost-benefit-risk-responsibility sharing is as follows:

- With a cost plus regime, there is uncertainty in the allowable project cost as there can be subjectivity in its determination by the Commission. The Multi Year Tariff (MYT) framework provides for setting target levels of performance for a longer control period.
- Although some Regulatory Commissions have begun to set station specific norms, operating norms / targets do not generally reflect the engineering characteristics of the plant, such as technology, capacity, vintage, operational issues and quality of coal supply. During the Inception period of this project it was discovered that operating parameters are derived numbers and are not necessarily set consequent upon an energy audit. As a result norms tend to reflect inaccuracies inherent in the method of determination and are sometimes felt to be neither realistic nor achievable. It is our view that in setting norms the regulatory objective should be to incentivise generators to reveal, for each unit, the efficient level of performance practically achieveable, so that overall performance levels will increase, the generators will make a return that they feel is acceptable and the allowed cost of generation will be at or close to levels that would prevail in a competitive market.
- During the control period, if a generator outperforms its targets, it may retain the benefit for the remaining years of the control period. However, the benchmarks for the next control period are likely to be recalibrated to take account of the actual performance during the previous control period. This may act as a disincentive for

performance improvement, particularly in later years of a control period, because performance benefits achieved are only retained in the very short term.

- The risk of operational failure lies with the Generator as both fixed and variable charges are based on norms and failure to achieve prescribed norms results in lower revenue recovery. Thus, although the benefits of increased performance are quickly passed to the Discom, in terms of lower purchasing costs, (additional energy is priced only at variable cost plus an incentive of 25 paise per unit) the Genco has a lower incentive to reveal his efficient costs and the Discom may be expected to pay higher charges in the long term.
- There is no supply commitment from the Generator but the Discom is committed to buy all that is generated by the Generator. The Discom has to make good any shortfall in supply by the Generator and is exposed to the costs of purchases from the wholesale market/other sources. Short term purchases from the central Pool in India, if available, can be expensive.

3.2. Beyond Regulatory Framework

3.2.1. Power market Situation

- **New build more attractive:** Because a large volume of capacity can be added in one go it may be argued that there is an inherent bias towards new build plant, compared with EE R&M projects. To an extent this is understandable given that most of the states of India (excepting for Eastern Region States) experience power and energy shortages. R&M investment is perceived to carry higher risk as the certainty of beating the operating performance targets for higher returns is greater with new build plants. As per the current regulatory framework the performance targets for new build plants and existing plants are the same. R&M can be an economically feasible supply option given that the gestation period of new plants is at least 2-3 years and often more than 4 years (thermal plant can be 4 years and Hydro plants as much as 6-8 years) whereas the outage for R&M may be less than a year. Furthermore, the cost of building a new plant is more than the cost of adding the equivalent capacity through R&M of existing plants. The latter part of this report recommends a Public Private Partnership (PPP) framework for mitigating perceived R&M risks.
- **Energy Shortages during Outage:** There are two issues related to shut down of the plant to facilitate R&M. Availability of power to compensate the energy lost due to shut down and the cost of such power. These are critical issues for a Discom. Currently the cost of short term power is very high and can significantly affect the cash strapped Discom even in its day to day operations. The other option is to shed equivalent load (demand) but the political ramifications of such action can be adverse, even though benefits of R&M are higher in the long run. The adverse impact of the energy shortages can be mitigated if additional power can be made available by the Central Government through allocation of firm power, from the unallocated share of the Central Sector stations (as provided in the R&M guidelines dated 3rd February 2004). However it appears that in practice this provision has not yet been used. The Discom may be required to procure costlier power and to recover this would have to approach either the regulator, for a pass through in the Retail Tariffs, or the State Government, for a subsidy. Non-recovery of the cost could aggravate the financial distress of the Discom and would be a continuing barrier to a Discom's willingness to agree to EE R&M schemes.

3.2.2. Institutional Capacity

- The project development capacity of most State Generators is relatively low. There is also significant potential for improvement in O&M practices in the state generating stations, particularly in measurement and monitoring systems required for increasing accountability. This is discussed in greater depth in Annex 4 of this report.
- The low level of institutional capacity is also recognised by the Ministry of Power (MoP), which has, in its own R&M guidelines, provided for technical and managerial support by consultants such as National Thermal Power Corporation (NTPC) for project report preparation and development of prudent Operations & Maintenance (O&M) practices.
- State Generators also appear to have a relatively low risk appetite and require the EE R&M executing agency to guarantee plant performance for an extended period of time beyond completion of EE R&M works. They also appear to prefer R&M executing agencies to be the Original Equipment Manufactures (OEMs), whilst OEMs have a preference for new build plants, which they believe offer better returns.
- Our discussions with generators and Press reports have led us to believe that there is limited availability of contracting capacity to support R&M projects,[5] although discussions with a small number of contractors have suggested the situation may not be as bad as that described to us. Given the rate of growth in the World and Indian economies it may also be the case that present demand for contractor services is in excess of supply.. As a result of these factors contractors may seek one or more of the following:
  - higher prices, to offset increased risks, where such risks can be priced;
  - limits on liability, where risks cannot be priced;
  - an input to the design of the R&M programme to offset risk by ensuring that the generator undertakes a (potentially more expensive and possibly over-engineered) full R&M programme, rather than a piecemeal approach; and/or
  - an ongoing management contract that would offset the risk in relation to guarantees of future performance and share the benefit of any performance enhancement.

[5] Power Line – March 2008 Edition

4. FRAMEWORK FOR RANGE OF OPTIONS

4.1. Framework for incentivising efficient R&M decisions

A review of potential options for encouraging energy efficient R&M projects can be developed along the following decision points;

- Permissible under the Electricity Act 2003
- Role of the Regulator
- Approach to pricing
- Regulatory Regime

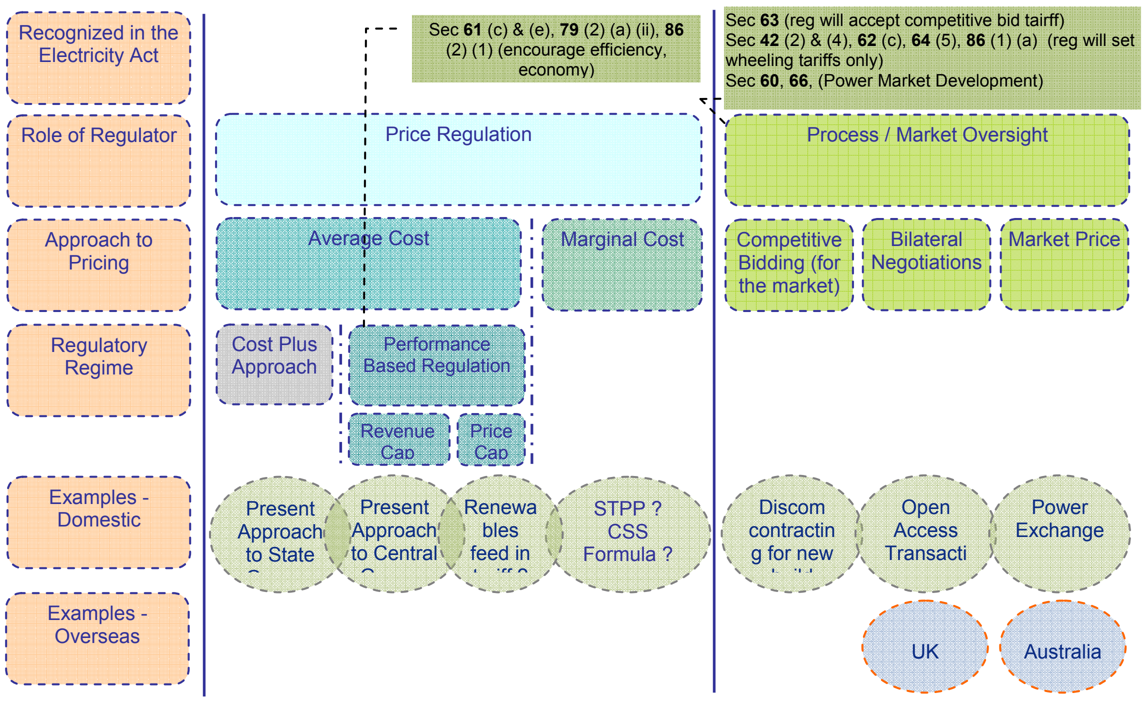


Figure 7 - Framework for Selecting Options under different Regulatory Regimes in incentivising efficient R&M decisions

The proposed framework, as evident from Figure 6 above is within the ambit of sections 42(2 & 4), 60, 61(c & e), 62(c), 63, 64 (5), 66, 79 (2) (a) (ii) and 86 (1(a) & 2 (1)) of the Electricity Act 2003.

The decision making framework identifies a number of broad approaches, from an intrusive regulatory approach that requires full justification of decisions in advance, to a process of market oversight and price discovery, which attempts to stimulate the interplay of market forces and places the risks of a poor decision with the utilities,

4.2. Evolving Indian Power Market impacts choice of regulatory role

4.2.1. Generation Price Determination – Current Scenario & Way Forward

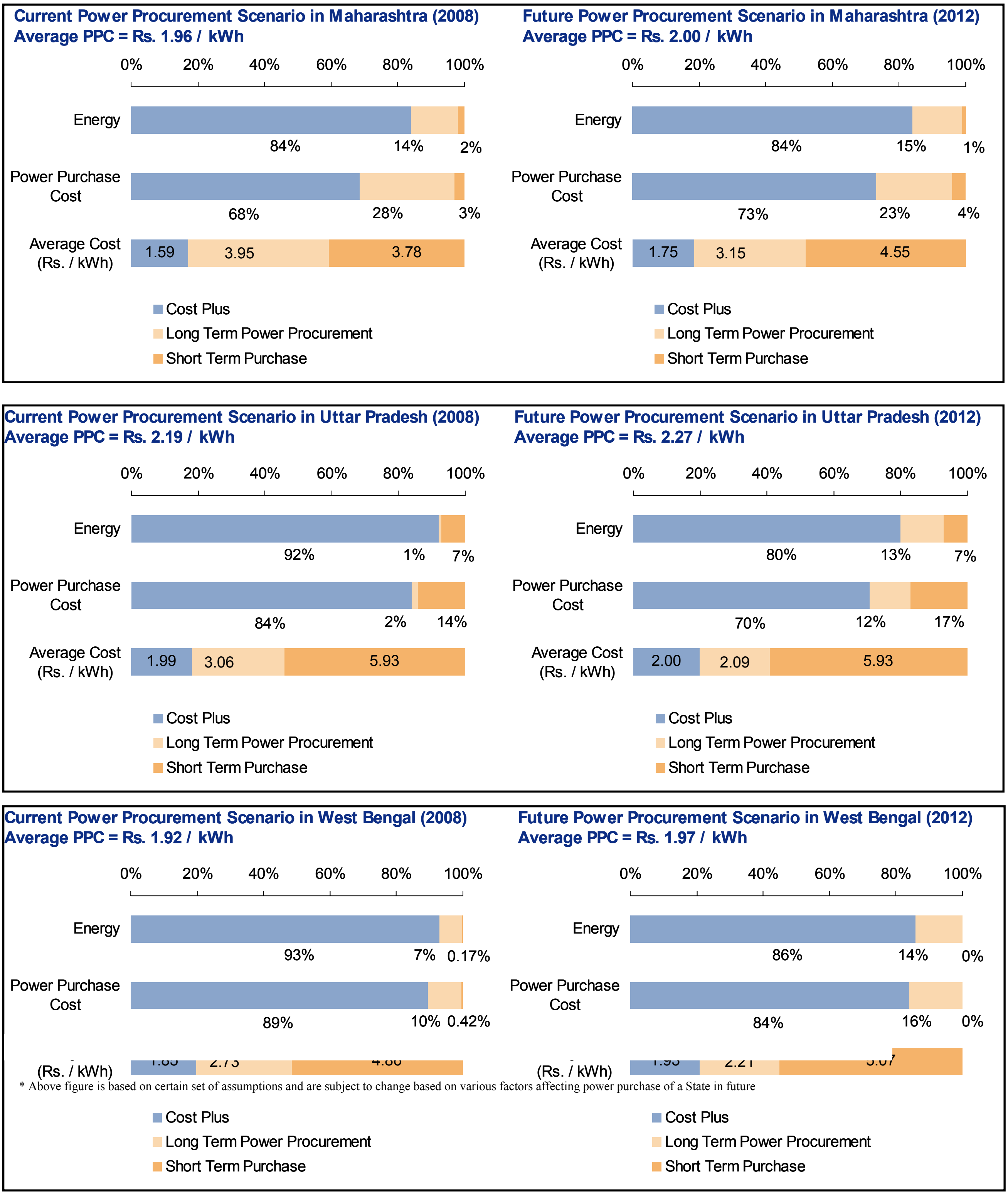
- Prior to the enactment of "The Electricity Act, 2003" (EA 2003) all new generation capacity required clearance/approval from the Central Electricity Authority (CEA). As a result of the provisions of Section 7 of the EA 2003 only new hydro capacity now requires prior approval by the CEA.
- However, as described in detail in Annex 4 of this report, tariffs/revenues for all the existing Central or State owned Gencos are determined on the basis of Tariff Regulations notified by the respective Regulatory Commission.
- In addition, the National Electricity Policy (2005) and National Tariff Policy (2006) require that all future power requirements should be procured competitively, except in cases of expansion of existing projects, or where there is a State controlled/owned company as the identified developer. In this case regulators must determine appropriate tariffs, based on norms. However, this exemption from competitive bidding is scheduled to expire in 2011 and from that date State Gencos are also expected to come under a competitive bidding regime.
- Pursuant to the aforementioned policies, the Ministry of Power has issued Competitive Bidding Guidelines (2005) and Standard Bid Documents (2006) based on which Discoms can invite bids for procurement of Long Term Power from newer stations. Discoms of many states like Uttar Pradesh, Maharashtra, Gujarat, Haryana etc. have initiated this process, whereby the price of power is determined through the bidding process (so called "competition for the market").
- The Electricity Act, 2003 has also been successful in introducing trading of power in India through the introduction of Open Access arrangements, at both regional and state level (so called "competition in the market"). Currently there are 26 Trading Licensees in India and about 11,943 MUs was traded during the period April 2007 to September 2007. This was 51.15% higher than the volume of traded energy in the previous year and it is expected that the volume of electricity traded during FY 2007-08 will be approximately 20% more than the FY 2006-07.[6] Currently the share of energy procured through trading is lower in the individual State Power Purchase plan, but its share is likely to increase in the coming years with the introduction of a Power Exchange in India.
- Thus the current portfolio of most of the Discoms is a mix of cost plus, competition for the market and competition in the market.

4.2.2. Cost plus Approach to Continue

- Current portfolio of the three states that were the focus of this study (Maharashtra, West Bengal and Uttar Pradesh) shows that more than 84% of the energy purchased and more than 68% of the power purchase cost in the year FY 2007-08 is subject to a Cost plus Regime with tariffs/revenues determined the respective ERCs.
- Analysis of the demand supply situation in these States for the next 4 years shows that energy procured under the cost plus regime will continue to dominate. Our analysis of the position in each of the three states is illustrated in Figure 8 below.

[6] Annual Report of Ministry of Power for the period 2007-08

Figure 8 - Current & Future (Likely) Power Procurement Scenario for the States of Maharashtra, Uttar Pradesh & West Bengal



* Above figure is based on certain set of assumptions and are subject to change based on various factors affecting power purchase of a State in future

- The estimated demand and supply position in the coming 4 years of the 3 States highlights the continuation of the existing situation, whereby most energy (more than 80%) will be procured from Generators under a cost plus regime.

- It is assumed in this analysis that there will be no significant change in fuel mix and that stations that are scheduled for commissioning during the next 4 years will be brought on line without slippage. (Slippage of any one of the generation project will increase the gross energy deficit of the State that has an allocated share of the plant output) The behaviour of the State during the deficit situation as evident from historical trend is likely to continue in the future as well but procurement through Unscheduled Interchange is likely to decrease since the rate of UI power is very high, at Rs. 10 / kWh.
- Also it is envisaged that the price of short term power would be determined by the market conditions.
- Another significant conclusion is increased reliance on the open market for meeting increased energy requirements. The power market will evolve as the share of market determined power purchases increases. The involvement of various states in power market will depend upon such purchases.
- When supply matches demand, generators should compete among themselves to provide power at the lowest possible cost. Such competition is likely to encourage generators to adopt best O&M practices and to ensure high levels of operational efficiency. However such a scenario is not likely in most of States during the next 4 years.
- Given the continuing demand – supply gaps, the pace and form of introducing existing plants into the competitive market place will need to be carefully calibrated and needs a detailed impact assessment.
- Hence, there is a need to explore a larger range of options for incentivising energy efficient R&M, but each state would need to analyse these in detail, in their context, to arrive at the one that is best for them.

4.3. Conclusions

- The present power market is dominated by cost plus bilateral power purchase agreements. However the share of market based purchases is on the rise.
- The Power market has evolved from a regulated to partially deregulated one and in future it is likely to be further deregulated. However, various states are likely to be involved differently in the power market according to their own supply-demand balance and the volume of power that is already treated under a cost-plus regime and that under a market based regime. .
- The proposed interventions for promotion of energy efficient R&M need to evolve both in a manner that can dovetail with the prevailing cost plus regime and in a manner that can dovetail with market based solutions and a broad range of options is required.

5. OPTIONS CONSIDERED FOR THE STUDY

In this Section we discuss a broad range of options for regulatory approach that can promote R&M within a cost-plus regime as well as in regimes where revenues are more market driven. The focus is on improving allocation of risks and returns between the different stakeholders carrying out the investment and subsequently benefiting from it.

As outlined in the introduction to this report, the diverse contexts in different Indian states, combined with the different pace of power market development, necessitated that this study identify a range of options suitable for different circumstances. It is expected that Regulatory Commissions will consider the approach that best fits their own position and the readiness of the Discom and the Generator to absorb the risks and benefits inherent in our options.

The relative mapping of these options across various regulatory dimensions is illustrated in Figure 9 below and discussed in Section 5.1.

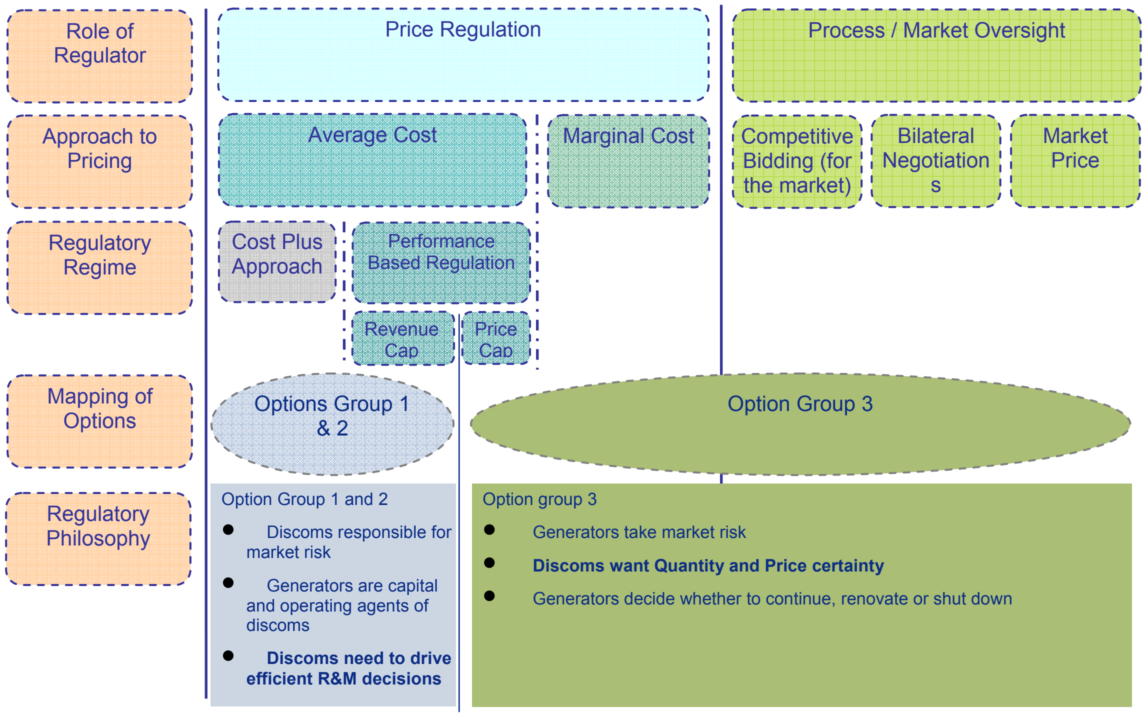


Figure 9 - Mapping of various options to incentivise energy efficient R&M in various regulatory regimes

5.1. Discussion of Options

The range of possible options that has been considered is: -

- **Option 1:** ***Modification of Traditional cost-plus approach*** This is a cost-plus approach, with allowable costs based on historic costs incurred. However, in this case, the R&M proposal is Discom driven. The Discom considers those R&M options which would fit with its least cost power procurement plan. The framework is similar to the existing regulatory framework except that a band of operating norms is set and the proposal is Discom driven, rather than Generator driven. If actual performance is within the band of norms the Generator may recover actual costs, but if it is worse than this band cost recovery is limited to normative levels. The generator is only committed to supply actual volume generated and the Discom is required to source any shortfall from the market. The operating risk to the generator on account of the band of operating norms is lower than with the existing regulatory framework.

- **Option 2:** ***Advanced cost-plus option with price certainty over longer period*** This is an advanced cost-plus approach, based on Performance Based Regulation. The choice of R&M investment is made in the same way as in Option 1 i.e. the Discom proposes the investment only if it fits its least cost power procurement plan. However, there is price certainty over a longer control period, which could be set equivalent to the extended plant life. This price certainty allows for cost planning and profit retention for a longer period. The operating norms are thus set for the extended plant life. The Generator could be allowed a higher return than allowed for new build plant, through the norms for the debt equity ratio, recognizing that the cost of debt for R&M projects is different from new build, and by allowing a higher return on equity to incentivise moving out of the traditional cost-plus regime.

  We have also identified two variants of this option, depending on the way in which norms are determined. Norms could be determined either by the Regulator, or through competitive bidding. The prerequisite for implementing market determined norms is Private Sector Participation (PSP) for contracting out both R&M and O&M over long term.

- **Option 3:** ***Marginal cost based tariff determination for additional generation*** This option is distinct from options 1 and 2 in that the R&M investment decision does not involve the regulator and the Discom. In response to the pricing regime, the Generator would decide whether to renovate, continue or scrap the plant. The Generator is committed to supply only the equivalent of the pre-R&M quantity, at pre-R&M rates, for an agreed period. The price of the additional quantity supplied (whether through R&M or otherwise) is determined through marginal cost principles. There can be a number of variants of this option depending on the principle of marginal cost determination. This approach ranges from Performance Based Regulation (PBR) to market based contracting.

5.1.1. Comparison of various options

- A comparison of the various options is given in Table 13 below:

Table 3 - Comparison of options

Aspect of regulatory process	Existing (at State Level)	Proposed Option 1	Proposed Option 2	Proposed Option 3
Origin of R&M Proposal	By Genco	Discom: develops R&M options in Least Cost Power Procurement plan. The Discom makes final decision on an R&M project. Genco: develops alternate efficiency improvement proposals in order to secure enhanced sales to the Discom	Same as Option 1	Genco: Decides whether to do R&M or not depending on competitiveness of marginal cost of the additional supplies compared with the Discom's alternative power sources.

Aspect of regulatory process	Existing (at State Level)	Proposed Option 1	Proposed Option 2	Proposed Option 3
Capex Evaluation	Engineering Approach. At best, **Genco perspective**	Regulator to take holistic **Discom perspective**	Regulator to take holistic **Discom perspective**	Regulatory approval not required – Genco risk
Capex	Actual	Actual	As approved ex-ante (no ex-post claw back)	Actual – at Genco risk
Operating Parameters	Norms pre-set – don't distinguish between R&M or No R&M. Control Period 1 to 5 years	Actuals, within a normative band; to be reset at end of each Control Period	Normative, trajectory set for the entire plant, for the Extended life (greater than Control Period)	Actual – under/over performance is Genco risk or benefit
Supply	Generator is responsible for actual output. Discom is committed to take actual output.	Generator is responsible for actual output. Discom is committed to take actual output.	Generator is responsible for actual output. Discom is committed to take actual output	Generator commited to supply pre-agreed contractual minimum quantity. Discom committed to buy minimum contract quantity. Long-term contract may be necessary to give Genco certainty
Return on Capital	Same as new build	Existing returns to continue	More attractive than new build or continue with current (lower D/E; higher RoE)	Market determined – reflects additional market risks faced by Genco – return would also reflect length of contract/degree of certainty and extent of minimum off-take provision.
Tariff Structure	Two part, plus incentive	Two part, plus incentive	Two part, plus incentive, plus UI regime	As agreed between parties. . Single part for committed supply.

5.1.2. Option 1 – Modification of Traditional cost-plus approach

Option 1 has been summarized above and the details of the risk and benefit sharing have been elaborated in Section 2.1.2 of this report. Details of the Investment Approval Process for both Options 1 and 2 are as described below:

- ***Investment Approval Process in Option 1 & Option 2***

  Within the cost-plus regime, the regulatory framework will need to specifically take account of the R&M investment, as it does for other investments where the investors are assured a rate-of-return on the specific investment (e.g. in new build generation within State Gencos, transmission investments and distribution investments). Hence, the investment approval process for R&M investment will need to follow the same principles as for approval of such investments i.e. prudence check by the Regulatory Commissions.

The broader steps in the R&M investment approval process would need to be the following:

- The Genco would need to identify the range of possibilities for efficiency improvement in existing plants and the associated cost and output implications. This would need to be discussed with the Discoms to assess relative merits of the possibilities compared with their other purchasing options.
- In proposing its long term power procurement plan, the discom would need to include the appropriate efficiency improvement option in its plan.
- In approving the long term power procurement plan and Genco's investment plan, the ERC would consider the attractiveness of the investment option based on an economic evaluation from discom/consumer perspective (i.e. based on the full evaluation of alternatives).

5.1.3. Option 2 - Advanced cost-plus option with price certainty over longer period

In this option the control period is set equal to the extended project life. The normative parameters used to determine tariffs remain unchanged for the extended project life. The incentives for better performance are strong as the benefits can be retained for a longer period of time. This option offers greater incentive as compared to option 1 for R&M projects. The operating framework proposed for the option is provided in the following table. The regulatory framework will have to be accordingly oriented.

Risk and Benefit Sharing in the Option 2 is as described below:

Investment Decision making process

- The Discom explores various supply alternatives for meeting its energy requirement and finds R&M of the existing plants as the least cost option.
- The Discom along with the Generator explores the possibility of R&M of existing plants.
- The Generator explores the technical feasibility of carrying out R&M of existing plants. It proposes the R&M projects that are financially viable to the Discom. It indicates the R&M cost and the output that are likely to be achieved over the plant life and makes an assessment of likely performance against probable norms. The Generator is interested because of its financial viability.
- The Discom evaluates the proposal and approaches the Commission for its approval to the additional volumes and costs and demonstrates before the Commission the economic viability of the R&M project (the least cost supply option over its supply planning horizon).

- The Commission approves the R&M cost using economic evaluation criteria and sets the norms for the entire plant life (beyond the existing control period). The approved R&M cost and the operating norms form the basis of tariff to be paid by the Discom to the Generator.
- The Generator arranges the funds and manages the R&M project.
- The Generator enters into a long-term PPA for the committed supply, at the agreed rates, for the extended plant life.

Process of R&M Evaluation

- A Regulatory framework, which indicates the information requirements, the process of evaluation and the decision criteria (economic viability) is in place. There is a certainty in the R&M cost and the cost benefit analysis.
- The Generator seeks in principle approval of the project cost and completion time before investing.

Responsibility over time & cost over runs

- The Generator is required to complete the R&M project within the approved time & cost. The consequences of time (IDC) and cost over runs (Capital Costs) are entirely on the generator.
- The consequences of time and cost over runs can be passed on to the Discom by the Commission if the Generator is able to establish that these over runs are for reasons beyond its control.

Operational Risks

- The operational parameters are considered to be controllable by the generator. The Generator is entitled to receive benefit or absorb losses consequent to actual performance being better or poorer than the norms. Benefits result from incentives for excess scheduled generation while losses are because of reduction in allowable fixed charges and increase in actual variable charges over allowable charges. Irrespective of the actual performance, the Discom pays the tariff determined by the Commission.
- Allowable quantity is computed on the basis of norms and fuel heat content. Variation in fuel heat content is passed on to the Discoms
- Any variation in the fuel heat content and the price over the values considered for tariff is passed on to the Discoms through Fuel cost adjustment (FCA) formula.

Supply Risk

- The Generator is committed to supply all that it generates. There is no commitment to a firm supply.
- The Discom is committed to buy the entire output of the Generator. Consequently if there is any shortfall in the energy availability, the Discom has to approach the market/other sources for additional supplies. The Discom thus faces the risk of increase in power purchase cost or revenue foregone if there remains any unmet demand.

The above operating framework can be made applicable even if one of the many units of a station is considered for R&M. Post R&M, norms for the entire station could be set considering the operating norms approved for the unit. The baseline data for fixing norms should come from an actual energy audit.

Option 2 offers a better incentive mechanism as compared to Option 1 for R&M projects as the Generator has greater certainty in investment evaluation and approval. Also the Generator has stronger operational incentives as it can retain the benefits for the elongated control period of extended plant life.

- ***Option 2B – IPP-type model for private sector participation***

While both the above option 1 & 2 improve the risk-return sharing compared to the existing situation, they do not address the barriers outside the regulatory framework. Specifically, while option 2 requires long term commitment to efficiency improvement trajectory, State Gencos may not be willing to make this commitment in absence of guaranteed post R&M performance by the R&M service provider. Bringing in an investor-operator to undertake both R&M (as well as potentially O&M, subsequent to the R&M work) could help address this hurdle.

Hence, we suggest a Private Sector Participation (PSP) model, where the R&M investment and O&M responsibilities are bundled together and contracted to a private sector investor-operator. The investor-operator could be selected through a Tariff Based competitive bidding procedure, consistent with the guidelines under Section 63 of the Act. This would also help to obviate the need for the ERC to determine the appropriate efficiency improvement trajectory and the return differential to justify the risk. We have called this the "IPP type" model, because as in case of IPPs, the need for investment is identified by the power procurer (jointly with the Genco, in this case), and the investor is assured a minimum revenue, subject to performance parameters (availability, heat rate, etc) being met. The demand risk, in this case, continues to be substantially on the power procurer, as the investor's returns are largely linked to plant availability

5.1.4. Option 3 - Marginal cost based tariff determination for additional generation

R&M investment decision is left to the generator and regulatory approval for the proposed capex is not required. Two scenarios have been considered in this option, as follows:

a) Option 3A

- Existing terms and conditions of PPA applicable for remaining plant life. Generator has the obligation to sell for the remaining life of the plant Pre-R&M quantity at Pre-R&M rates only. The generator is free to decide what to do with the plant beyond the present economic life.

b) Option 3B

- Generator is commited to sell part of the post-R&M incremental capacity to the Discom. Generator has the commitment to sell (a) Pre-R&M quantity at Pre-R&M rates (Q1, P1) as in Option 3A (b) a higher level of generation (Q2) at marginal cost (P2) (c) any further generation beyond Q2 may be sold at market rates.

- ***Option 3A***

In this option the plant is required to operate in a market environment after the existing economic life of the plant is over. The Generator is committed to sell the agreed quantity at agreed rates for the remaining plant life, and thereafter the Generator can take the decision whether to continue, renovate or shut down the plant. The Discom is committed to buy the generated quantity at regulated rates during the remaining economic life of the plant only. The Generator's decision to undertake R&M in such a regime would depend on the post R&M generation cost, compared with the cost of a new plant. If post R&M,

cost is lower, the Generator would undertake R&M but may choose not to supply to the Discom for the extended plant life. The Discom would want to continue with the Generator only if it gets additional supplies at better rates than from a new plant. The scenario offers appropriate market based incentive for R&M projects.

- ***Option 3B***

This scenario is a mixture of market and regulation based interventions. This scenario is designed with the intention of incorporating Discom's claim on existing plant of the Generator. The Generator has a firm commitment to sell Pre-R&M quantity at Pre-R&M price (determined by the regulator) to the Discom. Additional generation (say, due to expected improvement in PLF) is sold at marginal cost (P2) for the extended plant life. The Discom is committed to off take the agreed quantity at the agreed price. In addition to this, the Generator can sell further generation (say, due to increase in Capacity (MW)) in the market.

The description of the two scenarios is given in the table below:

Table 4 - Comparison between Option 3A & 3B

Aspect of regulatory process	Option 3A	Option 3B: Designed to incorporate Discoms' "claim" on existing plant
PPA / No PPA	Existing terms and conditions of PPA applicable only for remaining plant life.	Quantity, Price, Term locked in PPA (term greater than remaining plant life) • firm supply commitment; single rate; fuel and inflation indexation. Failure to arrive at agreement would keep plant under Option 1. Agreement leads to a price P2 and quantity Q2 for at least part of the new capacity post-R&M. To be reviewed and approved by Regulator with due process.
Generator's decision on the un-committed capacity	Generator free to sell whatever is not committed under PPA – can decide whether to continue, renovate or shut down.	Generator free to sell whatever is not committed under PPA – can decide whether to continue, renovate or shut down.
Additional requirement of Discom	Discom to do additional procurement through Competitive bidding – generator free to participate.	Discom to do additional procurement through Competitive bidding – generator free to participate.

- ***Option 3B2 – "Generation Franchise Model" for private sector participation***

It is intended that that both the above options (3A and 3B) improve the risk-return sharing compared to the existing situation. This will be assessed in the next section. At the same time, the institutional readiness of the State Generators to operate commercially in the less certain environment created by market based returns may need to be increased. Towards this, introduction of a Private Sector Participant with stronger incentives and capability to manage the risks and returns may be helpful.

Hence, we suggest a PSP model, where the plant operations are franchised to private sector investor-operator. The investor-operator could be selected through a Tariff Based competitive bidding procedure, consistent with the guidelines under Section 63 of the Act. This would also help to obviate the need for the ERC to determine Q2, P2, etc. We have called this the "Generation Franchise Model", because it is similar to the Distribution Franchise model being attempted in different states, in that it franchises inefficient operations to a private sector player, provides him operational and investment flexibility, and incentivises efficiency though a single pre-determined value (payment for input power, in case of distribution franchise, and rate P2 in case of generation franchise).

The variants of Option 3B are described in Table 15 below. Option 3B3 describes the first steps that the state gencos and discoms would need to start taking in moving out from regulated and long term contracted arrangements, and moving into competitive power markets.

The operating framework for option 3 is provided in Table 16.

: Table 5 - Comparison of Options 3B1, 3B2 & 3B3 in relation to quantity, price & the role of the regulator

Particulars	3B1: Regulatory determination route	3B2: Competitive Bidding route	3B3: Bilateral negotiations between Discom and Generator
Quantity Q1	Based on existing capacity and existing PLF	Based on existing capacity and existing PLF	As negotiated
Price P1 (for sale of Q1)	Based on existing price	Based on existing price, or same as P2	As negotiated
Quantity Q2	Based on difference between "target PLF" and existing PLF, applied on existing capacity	Based on difference between "target PLF" and existing PLF, applied on existing capacity	As negotiated (including zero)
Price P2 (for sale of Q2)	Marginal Cost (as used in cross subsidy surcharge formula)	To be determined through competitive bidding	As negotiated
Role of regulator	Review and approve Generators proposal for each of the above	As per competitive bidding guidelines under Sec 63 of Act	Ascertain that negotiated deal more attractive than other options
Price for Quantity beyond above	Sale price not regulated	Sale price not regulated.	Sale price not regulated

Table 6 - Operating Framework for Option 3

Decisions	Option 3A	Option 3B
Investment • Responsibility for planning R&M • Responsibility for investment • Process of R&M evaluation	• The Generator decides to undertake the project if it is financially viable. Neither the buy in nor the approval of the Discom is required. • The Generator arranges the funds and manages the project. • The Generator enters into a new PPA for committed supply at Pre-R&M quantity and Rates for the remaining life of the plant. • The Discom approaches the Commission for its approval and on approval enters into the contract. • At the end of the plant life the Discom invites competitive bids for future supplies in which the existing generators can also participate	• The Discom along with the Generator explores the possibility of taking up R&M projects. • The Generator explores the technical feasibility of carrying out R&M of existing plants. It proposes those R&M projects that are financially viable to the Discom. It indicates the post R&M operating parameters that are likely to be achieved over the plant life. The Generator pursues the decision because of its financial viability. • The Discom evaluates the proposal and approaches the Commission for its approval. • The Discom demonstrates before the Commission the economic viability of the R&M project (the least cost supply option over its supply planning horizon) • The Commission approves the operating norms for the entire extended plant life. The approved R&M operating norms form the basis of determination of the energy to be delivered by Genco to the Discom. • The Post R&M quantity rates are set on the marginal principle as illustrated in the above table. • The Generator enters into a PPA for the committed supply and rates for the extended plant life. • The Generator arranges the funds and manages the

Decisions	Option 3A	Option 3B
		R&M project.
Responsibility over Time & Cost over runs	• The Generator is responsible for the consequences of time and cost over runs.	• The Generator is required to complete the R&M project within the stipulated time & cost. The consequences of time (IDC) and cost over runs (Capital Costs) are entirely on the generator. • The consequences of time and cost over runs can be passed on to the Discom by the Commission if the Generator is able to establish that these over runs for reasons beyond its control.
Operational Risks • Variations in SHR, Auxiliary consumption and availability • Variations in fuel quantity • Variations in fuel quality and price	• Generation changes due to variations in operating parameters have to be absorbed by the Generator and cannot be passed on to the Discom because the commitment is for firm supply. • Variations in fuel quality and price heat content over the values considered by the Commission for computation of Pre-R&M rates and quantity can be passed on to the Discom through Fuel cost adjustment (FCA) formula for the remaining plant life. • For quantity supplied either during the existing or extended life variations in fuel quality and price is allowable as per bilateral agreement. • In case of sale in the short term market these variations have to be absorbed by the Generator.	• Generation changes due to variations in operating parameters have to be absorbed by the Generator and cannot be passed on to the Discom because the commitment is for firm supply. • Variations in fuel quality and price heat content over the values considered by the Commission for computation of Pre-R&M rate and quantity can be passed on to the Discom through Fuel cost adjustment (FCA) formula.. • For balance quantity, the variations in fuel quality and price are allowable as per bilateral agreement. • In case of sale in the short term market these variations have to be absorbed by the Generator.

Decisions	Option 3A	Option 3B
Supply Risk • Supply Commitment • Off take Commitment	• The Generator has a commitment to supply Pre-R&M quantity at Pre-R&M rates for the remaining plant life only. The Generator is responsible for making good any shortfall in the committed supply at the agreed rates. • After the economic life is over the Generator has no further commitment to supply to the Discom. • The Generator can supply in the market any additional generation that becomes available due to R&M either during the remaining or extended plant life. • The Discom has a commitment to off take Pre-R&M quantity at Pre-R&M rates for the remaining plant life only. Discom would have to compensate the Generator for any shortfall in the off take quantity. • For additional purchases or after the contract period is over the Discom invites competitive bids. The existing Generator is free to participate in the bidding.	• The Generator has a commitment to supply Pre-R&M quantity at Pre-R&M rates and additional supplies due to improved PLF at marginal cost for the extended plant life. The Generator is responsible for making good any shortfall in the committed supply at the agreed rates. • The Generator can supply energy due to increased Generation capacity in the market. • The Discom has a commitment to off take Pre-R&M supply at Pre-R&M rates and additional supplies due to improved PLF at marginal cost for the extended plant life. Discom would have to compensate the Generator for any shortfall in the off take quantity.

The above operating framework is applicable even if one of the many units of a station is considered for R&M. Post R&M norms for the station would be set considering the operating norms approved for the unit. As discussed earlier the baseline data for fixing norms should come from actual energy audit.

5.2. Implementation Issues / Pre-requisites for Implementing the Framework

Table 7 below identifies four pre-requisites for successful implementation of the options we have identified, as follows:

- Legal and policy issues;
- Regulatory issues;
- Institutional framework; and
- Technical and Managerial Capacity

Legal & Policy: In some states the power purchase agreement between Generator and Discoms is very generic in nature. The agreement is neither for identified stations nor for any defined time period. The PPA does not identify the rights and duties of the parties if the life of the plant is extended. These PPAs will need to be modified, in line with the selected option.

Regulatory: Greater regulatory certainty is required. There needs be in place a regulatory framework for evaluating the cost and benefit analysis. The Commission must have the technical capacity and generation planning tools to ensure that proposed options are the least cost option, to determine prudent R&M costs and to fix the norms for the extended life of the plant. (Of course this is less significant for option 3, which leaves investment decisions and risks in the hands of the counterparties to the deal).

Institutional Framework: this considers whether the institutional framework of the market is sufficiently developed for each option

Technical and Managerial Capacity: this assesses the extent and nature of the managerial and technical capacities that project developers as described above

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Table 7 - Pre-requisites for successful implementation of various options

Option 1	Option 2	Option 3
Legal & Policy issues in R&M		
Modification in terms and conditions of existing PPAs through regulation/regulatory orders	Modification in terms and conditions of existing PPAs through regulation/regulatory orders	Modification in terms and conditions of existing PPAs through regulation/regulatory orders. Standard contracts are required.
Regulatory issues in R&M		
Station wise PPA for the entire economic life of the plant. The rights and the obligations of both the generator and the Discom should be defined once the economic life of the plant is over	Station wise PPA for the economic life of the plant. The rights and the obligations of both the generator and the Discom should be defined once the economic life of the plant is over	PPA for firm commitment of quantity of supply. The implications of default on the commitment must be explicitly provided for
Framework for cost & benefit evaluation and approval	Framework for cost & benefit evaluation and approval	Since decision is market driven, this is not required in the regulator process. A framework is required for evaluating and approving economic power purchases by Discom.
Regulatory certainty to the extent that norms will not be changed during the control period and if the actual performance lies in the band the approved cost will be allowed	Regulatory certainty to the extent that performance and cost parameters once set will not be changed during the extended plant life	Regulatory certainty that the PPA will be adhered to, irrespective of the generator's choice of whether to renovate or not, and the extent of profit being made by the generator.
Regulatory Commission should have the capacity to determine prudent R&M Cost, O&M cost and operating norms for the control period. The Commissions should have Generation Planning tools and the capacity to use them	Regulatory Commission should have the capacity to assess R&M cost, extended plant life, ability to set operating and O&M norms and index them for the control period. The Commissions should have Generation planning tools and the capacity to use them	Regulatory Commission should have capacity to regulate power market operations, and stay away from intervening in pricing decisions
Institutional Framework required for successful implementation of R&M		
Existing arrangement is sufficient	Existing arrangement is sufficient	Generator either to have plants with different generating characteristics or to function as a trader with a portfolio of contracts.
Existing arrangement is sufficient	Existing arrangement is sufficient	Well developed Power market for Financial Derivatives and physical delivery of electricity in short and long term required.

Option 1	Option 2	Option 3
Managerial & Technical Capabilities to manage and implement R&M		
Capabilities required to manage R&M projects and to develop & implement prudent O&M practices	Stronger Capabilities required to manage R&M projects and to develop & implement prudent O&M practices as financial implications of poor performance can be severe	Stronger Capabilities required to manage R&M projects and to develop & implement prudent O&M practices as financial implications of poor performance can be severe
Capabilities to operate in competitive power market not required	Capabilities to operate in competitive power market not required	Generator must have strong capabilities to operate in competitive power market
Capabilities to do financial analysis	Capabilities to do financial analysis and predict market price	Capabilities to do financial analysis, predict market price, deal with financial derivates and manage contracts

6. ANALYSIS OF THE OPTIONS

The current regulatory regime has been largely unsuccessful in promoting R&M projects, as a result of the barriers and constraints identified in Section 3 of this report. Investment and operational risks lie with the Generator, whereas supply risks rest with the Distribution Licensee.

Other barriers and constraints such as regulatory issues (which are described in section 2.1 of this report) the relative attractiveness of new build plant, the political impact and cost of short term energy shortages and the lack of Institutional capacity to execute R&M works have also contributed significantly to the slow development of R&M projects. These are discussed in detail in Annex 4 and are also summarized in Section 3 of this report.

In this Section we describe the methodology for evaluating the costs and benefits and the relative positioning of the Options set out in Section 5 above. In addition, we illustrate how each approach addresses the various barriers and constraints to R&M projects.

6.1. Illustrative Financial Model

- There are various permutations and combinations of approaches to output based incentives for R&M projects. Some require regulatory interventions, while others require market based interventions. The option that best aligns the benefits & risks and addresses the barriers that exist within the existing regulatory framework would normally be the preferred one. In order to judge which option has the best fit of costs and benefits, a model capable of computing these costs and benefits was created. This model computes the financial implication of a generator's decision to pursue R&M and of a decision not to pursue R&M and the economic implications for the Discom of a Power Purchase Agreement (PPA) with R&M and without R&M. Full details of the analytical steps followed by the modelling are set out in Annex 2 to this report. A brief summary of the output of the model is illustrated in Figure 10 below:

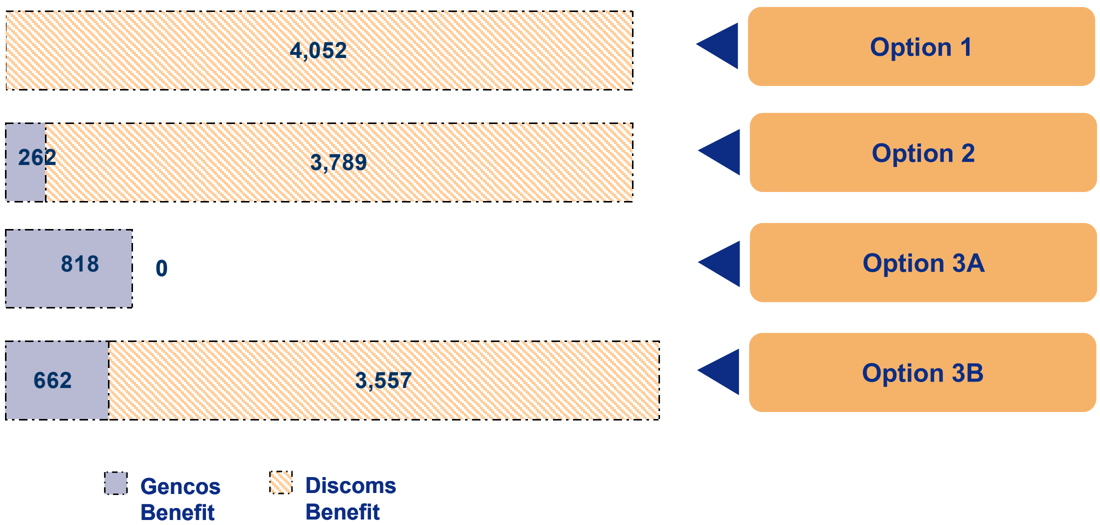


Figure 10 - Cost Benefit Analysis of selected options

- The Model takes into account the net surplus (cost reductions) to a Generator, which represents the difference between the Surpluses (Excess of Revenues over cost) to Genco with R&M and without R&M. Similarly the net surplus (reduction in power purchase cost) for Discom is the difference between the Power Purchase Cost with PPA and without PPA with the Genco.

- The Model assumes that the fixed cost of the plant for the first year, when the plant is shut down for R&M is capitalised and is considered as part of the project cost.
- It must be emphasized here that the financial model is based on the assumptions provided for a specific plant. The results would be different for different plants. Thus the outputs of the model are intended to illustrate how it can help in making efficient choices.

6.1.1. Option 1 - Modified Traditional cost-plus approach

Costs/tariffs are based on actuals and off-take and supply commitments are dependent on actual output levels.

For modeling purposes, for the "with R&M" scenario it has been assumed that the plant will shut down for up to 12 months and will not be entitled to any revenue. Post R&M it is assumed that the plant will generate at a post R&M rate, with enhanced capacity and improved operational parameters, for the extended life of the plant. In a "without R&M scenario" it is assumed that the plant will shut down at the end of its residual operating life. Operating parameters will lie within a band approved by the relevant Commission. Assumptions used for the modeling are set out in Annex 2.

The Discom in a without PPA (new) scenario will continue to receive units (existing units) at the existing pre R&M rate, for the residual operating life of the plant and will meet its additional requirement from the market. After the Generator shuts down the plant it is assumed that the Discom will procure its entire energy requirement at the generation cost of a new plant. In a "with R&M" scenario it is assumed that the Discom will procure the energy that is no longer available (as a result of the shut down necessary to due to permit R&M works) for a period of 12 months from the market and that thereafter it will receive energy from the renovated plant at post R&M rate.

Our model indicated that subject to these assumptions and in relation to the specific plant modeled, Option 1 provides a net financial benefit to the Genco of Rs. 0 Crs. (loss as fixed charges could not be recouped during shut down). On the other hand the net benefit to the Discom's benefit is Rs. 4,052 Crs.[7] The generator therefore has little incentive to propose R&M works.

6.1.2. Option 2 - Advanced cost-plus option with price certainty over longer period

Tariffs are based on norms, costs are based on actuals and off-take and supply commitments are up to the actual generation.

In this Option R&M investment is proposed by the Generator and, following a prudence check, is approved by the Regulator. Tariffs are based on norms, costs are based on actuals and offtake & supply commitments are up to the actual generation.

In a "with R&M" scenario, the plant shut for up to 12 months to permit R&M works to be undertaken and receives no revenue during this period. After R&M the plant

[7] Assumptions and Details of the Plant are provided in Annex 2

generates for the extended plant life with enhanced capacity and improved operational parameters. For scheduled generation in excess of normative generation (at post R&M norms) it receives normative energy charge and an incentive of 25 paise per unit[8]. As for Option 1, in the "without R&M" scenario the plant shuts down permanently at the end of its residual operating life.

In the "without PPA" scenario the Discom receives pre R&M units at the existing rate for the residual operating life of the plant only and during this period it procures its additional requirement from the market. After the plant shuts down Discom sources its energy requirement from a new plant. In. a "with PPA" scenario the Discom procures energy from the market during the shut down of the plant for R&M (for a period of up to 12 months). Thereafter it receives energy from the renovated plant at the post R&M rate and pays an incentive for units generated in excess of norms at 25 paise per unit.

Our model indicated that subject to these assumptions and in relation to the specific plant modeled, Option 2 provides a net financial benefit to the Genco of Rs. 262 Crs. and a net benefit to the Discom of Rs 3,789 Crs. The generator therefore has some incentive to propose R&M works but thie degree of incentive is still limited.

6.1.3. Option 3 - Marginal cost based tariff determination for additional generation

- ***Option 3A (PPA Pre – R&M)***

Tariffs are based on existing PPA (Pre R&M Quantum, Pre R&M Rate and Pre R&M Life).

In an R&M scenario the plant will be shut down for 12 months but then generates at an enhanced capacity and with improved operational parameters for the extended plant life. The Generator will have to buy committed units from the market to honour its PPA but will sell to Discom at pre R&M rate. It sells the additional energy that becomes available post R&M at new plant rate. In a without R&M scenario the plant generates for the remaining life of the plant and thereafter shuts permanently.

The Discom in both the with and without PPA scenario pays for pre R&M units at existing rates and meets any additional (unserved) requirement from the market. After the shut down at the end of the plant life, the Discom procures its energy requirement at market rates (new plant rate).

Our model indicated that subject to these assumptions and in relation to the specific plant modeled, Option 3A provides a net financial benefit to the Genco of Rs. 818 Crs. and nil net benefit to the Discom. This option provides the Genco with the greatest benefits, but provides the lowest level of benefit to the Discom.

- ***Option 3B (PPA for extended plant life)***

In a with R&M scenario the plant shuts down for 12 months, the Generator buys committed (pre R&M units) from the market and sells to the Discom at Pre R&M rates. For the extended life of the plant the Genco generates with enhanced capacity and improved operational parameters. It sells committed units to the Discom at a pre-

[8] as per existing CERC regulations.

R&M rate and sells additional energy generated post R&M at a negotiated / market determined rate. Whereas in a without R&M scenario the Genco generates pre R&M units at pre R&M rate and sells at the same rate for the remaining plant life - due to the PPA - it generates committed units (pre R&M units) at the new cost and sells at pre R&M rate for the extended period after the useful life of plant is over.

The Discom with a PPA scenario will buy pre R&M units at pre R&M rate for the remaining useful plant life as per the existing PPA and for the extended plant life. It will source its additional energy requirement from the market. Whereas in a without PPA scenario the Discom continues to get existing units (pre R&M units) at existing rate (pre R&M rate) only for the remaining plant life. Additional energy requirements when the plant is in operation or following shut-down are met from the market.

Our model indicated that subject to these assumptions and in relation to the specific plant modeled, Option 3B provides a net financial benefit to the Genco of Rs. 662 Crs. and a net benefit to the Discom of Rs 3,557 Crs. The generator therefore has a reasonable incentive to propose R&M works, but the main benefit flows to the Discom.

6.2. Responsibility and Risk sharing in the Three Options

The responsibility and risk sharing between generator and Discom in each of our three options is summarized in Table 18 below. In summary:

Table 8 - Risk - Responsibility between Genco & Discom

Responsibility / Risk	Option 1		Current Approach to Existing Plants		Option 2		Option 3	
	Genco	Discom	Genco	Discom	Genco	Discom	Genco	Discom
Investment Decision Responsibility								
Risk of inefficient Investment Decision								
Investment Execution Responsibility								
Risk of inefficient Investment Execution								
Operational Responsibility								
Risk of “inefficient” operations								

6.3. Redressal of Non Regulatory Barriers & Constraints

Section 3 of this report identified the constraints / barriers that inhibit the development of R&M projects by Gencos. Sections 6.1and 6.2 above describe how each of our options addresses the regulatory barriers. Table 19 below now shows how the non regulatory barriers are addressed by each option.

Table 9 - Non Regulatory Constraints / Barriers

Barrier / Constraint	Option 1	Option 2	Option 3
Power Market Situation			
New Build more attractive	Risk, as compared to the existing framework, reduced , but still barrier exists	Continues but partially overcome as incentives for R&M projects improved	Substantially overcome in Option 3A because –there are strong incentives for R&M projects. In Option 3B some barriers persist, depending upon the strength of the market incentives to R&M decision making
Energy shortage for Distribution Licensee during outage	Continues, Discom has to arrange for the power during the outage of the plant	Continues, Discom has to arrange for the power during the outage of the plant	Genco responsible for sourcing power during outage. Consequences of market volatility rest with the generator. Availability of short term power a constraint
Institutional Capacity			
Relatively low development capacity in State Gencos	Projected identification, evaluation, and development capacity required in Discom, Regulator and Generator	Greater incentive to address this barrier as stakes are high on better performance. This barrier will need to be addressed either through in house capacity development or use of PPP mode	Incentives to undertake successful R&M are strong . Barrier will need to be addressed either through in house capacity development or use of PPP mode
Commercial orientation, but preference for low risk	Addressed, since risks are shifted towards the Discom.	Private Sector Participation ("IPP Model") suggested to address this	Private Sector Participation ("Generation Franchise Model") suggested to address this

7. CONCLUSIONS & RECOMMENDATIONS

7.1. Potential Improvements

This sub-section sets out recommendations in relation to potential improvements to methodology currently in use for assessing energy efficient R&M projects. The following sub-section will conclude on the regulatory options put forward by this study.

Project assessment framework

At present guidance in relation to the assessment of proposed EE R&M projects is limited to that published by the MoP, for the purposes of funding support. The guidance indicates only a broad range of acceptable costs and a procedural requirement to prepare a proposal, in association with a consultant, for submission to the CEA. In addition, although the CERC has promised to prepare guidelines in relation to LE works this has yet to be published and may not cover all issues that would be relevant to a State Regulatory Commission. Existing guidelines are also focussed on plant load factor improvements rather than heat rate.

At state level the existing regulatory frameworks and incentives are, presumably, well known to those generators whose tariffs are regulated. Regulations provide in general that generators should make proposals for capital expenditure to their regulators and in some cases (such as UPERC) regulators have even instructed utilities to bring forth proposals for R&M schemes. However, whilst "in principle" approval of proposed investments may be possible, they do not appear to prescribe an analytical framework that would enable a generator to accurately judge the probability that a specific project would be accepted for inclusion in tariff calculations, on the basis that certain benefits would reasonably be expected to accrue and to be shared between the generator and customers. Part of the problem lies in the lack of certainty regarding the baseline performance of the plant in question.

Such limitations will necessarily mean that proposals are dealt with on an ad hoc basis. Thus, a generator's ability to judge the success of a proposal will depend on the nature of his relationship with his regulator. If he has a good relationship, based on mutual trust and respect, he may be able to understand the pressures that the regulator is working under and have a relatively high probability of making the correct judgement. If he has a relatively poor relationship and/or there is a lack of trust and respect the opposite may occur and the generator may decide not to commit resource to preparing a case for investment.

Although we recognise that regulators must take the decision they think is best, in the light of the circumstances applicable at the time, we recommend that a model assessment framework is drawn up that would set out the key data requirements and judgements to be made by regulators in assessing a proposal for energy efficient R&M and details of additional funding sought from the PFC, or another agency, in relation to the proposal. This should reflect also the considerations outlined in the proposed CERC guidelines, to the extent that these are relevant at state level.

Furthermore, as the benefits accruing from energy efficient R&M will also include wider electricity policy and social benefits, such as environmental enhancements from reduced coal burn, savings in imported fuel and, potentially, savings in the power purchasing costs of the Discom, we recommend that such issues are identified in the cost-benefit analysis. Of course, we recognise that it may not be possible for regulators to specifically take such matters into account within the existing regulatory framework.

In order to restrict the use of resources in considering projects that may never happen we also recommend that, in the light of the present situation, the project assessment framework should include a statement in relation to the availability of contracting resource to undertake the proposed works.

Power purchasing

As we have indicated, we believe there would be merit in regulators assessing distributors' power purchasing costs and plans over a reasonable time frame, say 10 years.

This would require distributors to demonstrate to the regulator their plans to meet the demands of their customers, from longer term and from short term purchases and permit the distributor to show how it would most cost effectively meet its requirements over the period as a whole. In turn this would permit state owned generators, supplying electricity at regulated tariff prices, greater scope to agree outage plans with the distributor and to facilitate energy efficient R&M projects, for example.

We also recommend that further consideration is given to the potential to permit distributors to contract with generators on a firm basis, such that the generator would be responsible for meeting the power costs and risks caused by an outage, whether planned or unplanned. Energy purchasing costs would therefore contain a risk premium related to the generator's own assessment of his reliability and this would encourage generators to improve their performance.

Setting of norms

Of course this situation is only of strong relevance to those states such as Maharashtra that are suffering from a significant power deficit and will have less relevance to the eastern States. The setting of appropriate benchmark norms, based on a sound understanding of the present operation and technical possibilities of each plant are key requirements of the regulatory framework, if we are to effectively incentivise energy efficient R&M.

The differing plant characteristics are to some extent already reflected in the currently accepted heat rate norms for 500MW plant and above i.e. 2450 kcal/kWh and for other plant of 2500 kcal/kWh, but there are also significant differences between plant within these broad bands. For example the design heat rate for a 200/210MW KWU manufacture plant is 2284 and the actual average in the period 2000-2003 was 2458, whereas the design heat rate for the same size LMZ manufacture plant is 2375 and the actual average was 2484. The level of incentive represented by the norm therefore varies considerably according to plant design.

It is also essential to take account of coal quality and of the inevitable degradation in plant performance pre R&M works, even for well maintained plant. Following an initial period of optimum performance for around 2 years, it would be expected that heat rate performance would be subject to short-term non-recoverable degradation at a rate of around 2%-2.5% and to long-term degradation of around 1%-2%, giving an average degradation of around 3%-4% over the lifetime of the plant and giving a revised heat rate of around 2650.

As indicated, coal quality is also an important factor. The reference coal for Indian plant is typically around, 4,100 kcal/kg (but may be higher) whilst typical deliveries may be as low as 2000 kcal/kg to 3000 kcal/kg, with reported deliveries in West Bengal as low as 1000 kcal/kg.

In order to take proper account of these factors and to begin to reduce the informational assymetries that they cause we recommend greater use of energy audits and measurement equipment, so that norms can be set from a position of knowledge in relation to the baseline.

A number of the key technical issues associated with setting of appropriate norms are set out in Annex 6.

In order to properly incentivise generators, norms should also be set for a reasonable period of time. A comprehensive EE R&M project, with for example residual life of 15 years could be subject to an incentive designed to share the full benefits of enhanced performance over that period on a fair basis. A number of regulators have already recognised this issue but we believe the lessons should be widely disseminated.

More detailed comments in relation to setting of norms and potential heat rate improvements are set out in Annex 6.

Energy efficiency policy barriers

Previously, we described the situation in relation to energy audits. These could be a vital tool for regulators in setting meaningful benchmark norms and we would therefore recommend that regulators urge state Governments to take appropriate action.

In addition, because there appears to be a discord between stated policy objectives and the submission of proposals for R&M projects, especially in some states, we recommend that regulators consider a more active approach to asset management by generators, for example by requiring them to bring forward proposals, following the example of the UPERC.

Although there is some risk that this does not replicate conditions in a competitive market, we believe that this is counterbalanced by the requirements of energy policy to bring forward projects that would enhance efficiency, reduce environmental emissions and enhance system security. The requirement to develop an asset management plan and submit it to the regulators would help to achieve two things; first, it would help identify poor performing stations in need of remedial treatment and that would possibly benefit from R&M works; second, it would provide a link to a longer term assessment of the distributors purchasing requirements, which we have recommended separately below.

An outline scope for the asset management plan is included in Annex 6.

Private sector involvement

As indicated above, we believe that, in certain circumstances, it may be attractive to generators and distributors to permit energy efficient R&M projects to be carried out on the basis that the management of the plant is contracted out following completion of the R&M works. This would put energy efficient R&M projects on the same footing as new build generation.

This should be a matter for detailed consideration and published guidance, but should be considered positively where it can be demonstrated, for example, that a greater degree of confidence is available in relation to future plant performance and the regulator is able to set specific norms for the plant that are tighter than would otherwise be the case under continued public sector management.

Regulatory resources

In summary our recommendations are that regulators will need the ability to:

- understand in detail the power generation process, heat rate losses, etc and be able to use power plant modelling software, such as Thermotool or Gatecycle
- implement (in consultation with the FoR and CERC) specific R&M project assessment guidance, designed to encourage EE R&M projects and the ability to assess specific generator investment and overall generator asset management plans;
- set stretching but achievable norms based on high quality baseline data/energy audits, an understanding of the impacts of coal quality and a high quality technical understanding of each specific operating unit; and
- review the longer term power procurement plans and efficient purchasing arrangements of the distributors and link these to the generators asset management plans and to an understanding of other major wholesale market developments;
- assess plans for private sector involvement

7.2. Conclusions on proposed regulatory options

As we have discussed, the various options we have identified are not mutually exclusive. Regulatory Commissions should consider them as illustrations of approaches for allocating relative benefits of R&M and the risks involved for the Gencos and Discoms.

Depending on the specific situation in their State, including the readiness of their Gencos and Discoms and on their current view of the regulatory and non-regulatory constraints we have identified, Regulatory Commissions should consider the application of the alternative approaches and carry out further analysis of the impact of specific actions on power purchase prices, power availability, reduced coal burn and other relevant factors.

7.2.1. Option 1 & 2

Within a cost-plus scenario (our Options 1 and 2), preliminary analysis shows that R&M is only likely to occur if it is driven by the Discoms, who would be receiving the majority of the benefits. Some initiatives that can facilitate R&M under cost plus framework have been proposed in the following paragraphs. We don't take a view here on whether the prevailing regulatory framework may require the Discom to pass through the returns partly or wholly to consumers.

Regulatory initiatives

- A framework which specifies the key data requirements and judgements to be made by the Regulator can be included as part of the existing regulations. This will provide the regulatory certainty to the investor as to how costs and benefits will be interpreted by the regulator. The Electricity Policy and social benefits, such as environmental enhancements from reduced coal burn, savings in imported fuel etc, which result from EE R&M, can also be included in the cost-benefit analysis of the proposed regulatory framework. The Discom's power purchasing cost may be assessed over a reasonable time frame, say 10 years. This would require the Discom to demonstrate that its long and short term power purchases meet the least cost approach and enable the Generators to agree to outage plans with the Discoms that will facilitate energy efficient R&M projects.
- It is desirable that the uncertainty inherent in actual performance is recognized and that norms are based on a properly undertaken energy audit that reflects the engineering characteristics of the plant as a whole and the specific characteristics of the units in operation. Norms and trajectories may be set in a manner that is stretching for the Generator, but should also be achievable and realistic. Norms that are designed simply to bring a Generator as a whole quickly up to the level of best practice are best avoided as they do not incentivise generator behaviour. The objective should be to incentivise the Genco to reveal, for each unit, the efficient level of performance that is achievable.
- It is desirable that Multi - Year Tariff Orders reflect the need for enhanced performance, potentially with extended periods in the early years of a control. The operational issues and quality of coal supply should be carefully considered while setting norms (as described in Annex 4 to this report).
- Norms may be set in a manner that provides the generator with an incentive to reveal the efficient costs applicable to his plant. Thus, Commissions can consider a tiered reward structure, with the generator achieving an acceptable income level for a reasonable improvement, but able to retain a higher level of incentive payment if it achieves a performance improvement well in excess of the target. Alternatively, this could take the form of a sliding scale reward system.
- Presently principles suitable for existing/new plants are applied for evaluating R&M projects. R&M has somewhat unique characteristics in terms of pre-investment risk involved and the characteristics of returns (a mixture of energy efficiency, life extension, etc.). A framework with a flexible approach for evaluating R&M projects is required. The additional capital expenditure can be recovered through depreciation over the approved extended plant life. The Debt Equity ratio of 70:30 for funding capital expenditure may not be insisted upon and the actual funding ratio may be considered. These plants have historically been poorly performing and there is a high probability that the promised performance may not materialize. Therefore, high proportion of debt financing may not always be available. The Generator may be compensated for higher project risk by allowing RoE in excess of existing 14%. Presently the O&M norms are based on the expenditure actually incurred in the past. This may not be appropriate for Stations which did not have prudent O&M practices (which now they intend to

implement) and because of cash crunch could not spend adequately in past on O&M. Higher premium on these accounts to the extent the new plant generation cost exceeds post R&M generation cost could be considered by the Commission.

- Regulatory Commissions have often been criticized for fixing norms but overlooking important factors such as technology, capacity, vintage and quality of coal available to the plant. One approach might be to link operating norms to the performance achieved by top 25% of the better operating plant of similar technology, capacity and vintage. This could be achieved through some form of frontier or Peer benchmarking (or similar analysis). Currently operating norms for the entire station are set but if some units of the station undergo R&M then the methodology for setting the operating norms for the station is required to be indicated upfront.
- Tariff should continue to be in two parts (fixed and variable) so that the plant can continue to operate under the existing ABT regime.
- Since the need for R&M is identified by the Discom, the Generator may have the right to either opt for option 1 or option 2, depending on the Generator agreement with the Discom's assessment and its risk appetite.

Institutional Capacity

- To address the issues around building institutional capacity, Private Public Partnership (PPP) approach for R&M projects could be used. The most desirable form could be the selection of investor-operator through competitive bidding for both R&M and O&M for the plant. The contract could be awarded either for the entire extended life of the plant or for the period after which the Genco feels that it would be in a position to develop and implement prudent O&M practices. The investor-operator would be in a position to offer performance guarantees as it has a stake in the good performance of the plant. To encourage PPP in R&M it would be desirable to put in place standard competitive bidding guidelines, contractual agreements and evaluation criteria as has been done by Ministry of Power (MoP) for Ultra Mega Power Plants (UMPPs) for competitive procurement of power. The performance guarantees / Tariffs / R&M cost discovered through the standard bidding process should be binding on the regulator for tariff purposes, in line with Section 63 of the Electricity Act.
- Ministry of Power vide its policy dated 28th October 1995 has provided for private sector participation in R&M projects. Policy has suggested various forms of participation, dealt with issues related to payment security, contracts & agreements and the procedure for implementation of R&M through competitive bidding. The Regulators need to encourage Generators to adopt this policy framework.
- The detailed format of the PPP model such as term of lease, methodology for determination of transfer value of assets at the end of the contract, rights and obligations with respect to existing manpower, accounting of new investment and transfer of existing rights on fuel supply etc need to be resolved upfront.

7.2.2. Option 3

"Firm" supply contracting (Option 3) has a lesser probability of Cost – Benefit – Risk - Responsibility mismatch and therefore no R&M specific regulatory interventions are envisaged. The Genco is free to decide to continue to generate, to renovate, or to shut down. The Discom can purchase power as it wishes, subject to regulatory controls on efficient procurement. The Discom would have to demonstrate that it followed an approved standard procurement process and that the price at which it was bought was in line with prudent expected outcomes.

The Generator through PPP approach can bring in the Institutional Capacity to manage investment and operating risk.

The costs of replacement power bought by the generator could be annuitised or included in the capital costs of a project and the increased costs could be spread over a longer period of time, perhaps equivalent to the period over which the expected benefits of enhanced efficiency would occur.

The generator, for energy supplied during unplanned outage, could charge a risk premium related to the generator's own assessment of his reliability and this would encourage generators to improve their performance.

7.3. Next steps

Having identified the barriers in a sharper focused manner and developed the framework for addressing them, a logical next step would be to implement one or more of the proposed options as demonstration pilots in select states and to use this work to identify the detailed implementation needs. Because a key finding of this study is that gaps in institutional capacity are also a strong barrier to efficient choices, pilots based on Private Sector Participation models could play an important role, serving to demonstrate the potential upsides of R&M choices and helping to address the risk perceptions surrounding such investments.

ANNEX 1 - EXISTING FRAMEWORK

Existing framework

Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commissions (SERCs) are currently using cost plus multi year regulatory framework for determining generation tariffs for existing stations (Central, State and Private Generating Stations which do not come under the purview of Competitive Bidding Process made mandatory under the Clause 5.1 of the National Tariff Policy). The norms for allowable cost and operating parameters are set upfront for the control period. This framework has not succeeded in promoting Renovation & Modernization (R&M) projects (although there are number of eligible projects) for reasons discussed in Annex 4. Before other options are explored it would be appropriate to evaluate the distribution of risks and benefits in this framework to Generators and Distribution Licensees (Buyers / Beneficiaries). Skewed distribution of Risks and Benefits may result in intended objective not being pursued.

Cost and Benefit inherent in the Existing Framework

The Investment, Operations and Supply cover the entire gamut of planning, implementing and the outcome of the decision to undertake R&M projects. The evaluation is based on the regulations and orders of CERC, Maharashtra Electricity Regulatory Commission (MERC), Uttar Pradesh Electricity Regulatory Commission (UPERC) and West Bengal Electricity Regulatory Commission (WBERC).

Investment Decision

Issues such as the responsibility for making an investment decision, process of evaluating the appropriateness of the investment and the consequences of cost and overruns have been considered in evaluating the risk and benefit distribution. The desirable outcome is the synchronization of the risk and benefit i.e. the same party bears the risk and benefit of the investment decision. This would provide the party taking the decision, the incentive to get the decision right.

Considering R&M as a Supply Option / Responsibility for Planning R&M

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• For Central Generating Stations, the responsibility for R&M although not explicitly identified by CERC / Ministry of Power (MoP), the responsibility lies with the Central Generating Companies. This arrangement facilitates R&M under the existing framework since these stations provide energy to more than one beneficiary state and it is not possible for an individual state to decide on the requirement of R&M.	• At state level there are explicit provisions in the regulations for Generation tariff determination / Power purchase cost for least cost and merit order approach. The distribution licensee is required to demonstrate before the Commission that its power procurement cost is based on least cost and merit order principles. This requires choosing the economically cheaper options between procuring additional power from refurbished plant or from new plant. MERC has provided for

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• Current regulatory framework provides incentive to the Central Generators to under take R&M projects to maintain or improve the operating efficiencies over the benchmark levels. Not achieving the benchmark levels would result in loss of fixed and variable charges.	only merit order dispatch. • Operating Norms for various parameters fixed by Regulatory Commission for the control period also require the State Generators to undertake R&M to achieve these norms. Failure to achieve these norms would result in loss of fixed and / or variable charges. • There is no evidence to suggest that States have evaluated between getting additional power from existing station and from new plants while approving the power procurement plant of the Distribution Licensees. • Efficacy of merit order principle in achieving least cost power procurement in shortage situation is limited as all plants get dispatched irrespective of the energy cost. • Except for Uttar Pradesh, there have been no R&M Schemes which have been scrutinized by SERCs before implementation. (ref – UPERC Order 7th November, 2006 for the approval of R&M Scheme for Obra B Project)

Process of R&M Project Evaluation

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• There is no clarity on this issue although CERC vide its order dated 11th August 2005 has stated that it would consider additional capitalization of additional expenditure on existing project on merit basis after detailed cost benefit analysis. • There is no precedent for in principle clearance of R&M projects. CERC in the cases of Tanda and Talcher admitted expenditure on R&M after it has been incurred and there were some disapproval because of accounting reasons.	• There is greater clarity in this regard in State Regulations which explicitly provide for expenditure approval before it is undertaken. • The regulations also provide for the approval of the business plans on rolling basis, which means in principle approval of capital expenditure plan. • UPERC granted in principle approval of the R&M cost for Obra "B" before R&M work began but there is no evidence that Financial / Economic Analysis was done to evaluate the reasonableness of the cost. • Maharashtra Electricity Regulatory

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
	Commission (MERC) directed Maharashtra State Power Generation Company Ltd. (MSPGCL) to maintain a clear demarcation of capital expenditure between revenue expenditure and submit Capital expenditure proposals for Renovation and Modernization schemes, for the Commission's approval. (ref – MERC Multi Year Tariff Order for MSPGCL dated 25th April 2007

Responsibility for Investment Cost and Time Over runs Risks

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• Generator evaluates the required investment and does the investment. • The regulations provide for the cost and time over runs to be borne by the Generator. However if the Generator can justify that such over runs were on account of reasons beyond the control of the Generator then the additional cost of these over runs can be passed to beneficiaries through tariffs. • The cost incurred for R&M as per the existing regulations is treated as additional Capital Expenditure over and above the historical cost of the plant which is admitted by the Central Regulator for tariff after prudence check and is passed on to the beneficiaries.	• Generator evaluates the required investment and does the investment. • The regulations provide for the cost and time over runs to be borne by the Generator. However if the Generator can justify that such over runs were on account of reasons beyond the control of the Generator then the additional cost of these over runs can be passed to beneficiaries through tariffs. • The cost incurred for R&M as per the existing regulations is treated as additional Capital Expenditure over and above the historical cost of the plant which is admitted by the State Regulator for tariff after prudence check and is passed on to the beneficiaries.

Operational Risk

This section deals with the Risks & Benefits associated with up and down side variations in operating parameters, fuel quantity and fuel price & quality. The alignment of risks and benefits provide the incentive to operate the plant at efficient levels and incentivise investment to improve efficiency.

Operating parameters (SHR, Auxiliary Consumption, Availability)

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• Operational norms have been fixed by	• Operational norms have been fixed by

CERC for the five year period FY04-09. • Consequences of actual operating performance being different from the norms are borne by the Generator. If the operating efficiency is below the norms there could be a proportionate reduction in fixed charges and loss in recovery of energy charges. If the performance is better the Generator along with the normative energy cost gets additional 25 paise for every unit of scheduled energy in excess of the scheduled energy at normative level.	the State Regulator for varying multi year period. These norms may also vary from one generating station to another. • For Maharashtra State Generating Stations the norms have been defined by the State Regulator till the FY 2009-10 in the Multi Year Tariff Order for MSPGCL for the period FY 2007-08 to FY 2009-10 • For Uttar Pradesh State Generating Station the operational norms have been defined by the State Regulator till the FY 2007-08 in its Multi Year Tariff Order for UPRVUNL for the period FY 2005-06 to FY 2007-08 • UPERC has also come up with draft amendments to the Terms and Conditions of Generation Tariff in Nov '07 wherein it has defined operational norms of State Generating Stations till the FY 2008-09. However, the Amendment is yet to be notified by the Regulator • WBERC in its draft Terms and Conditions Regulations, 2007 has defined operational norms for the State Generating Stations for the period FY 2008-09 to FY 2015-16 (8 years). However, the draft regulation is yet to be notified by the Regulator. • Consequences of variation in actual performance for the generation are same as that for Central Generator.

Variation in Fuel Quantity

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• The allowable coal quantity is determined on the basis of operating norms and expected Gross Calorific Value (GCV). Variation in actual quantity of coal purchased on account of variation in actual operating parameters (including transit losses) over the norms is to the account of the Generator only.	• Similar provisions exist.

Variation in Fuel Quality and Price

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• While computing the allowable energy charge expected price (including cost of transportation) and GCV is taken into consideration and any variation in the value of these parameters is passed on to the beneficiaries through Fuel Cost Adjustment (FCA).	• Similar provisions exist. • WBERC has proposed an incentive for procurement efficiency for the Generating Companies by considering UHV as an indicator of heat content and linking it to the price paid.

Supply Risk

Variation in generation is borne by the Discom, which has to be compensated through the procurement of energy either from the marginal station or from the short term sources (UI / Trading). For optimum quantity of power procurement at least cost the risks and benefits associated with supply must lie with the same party.

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• As per the existing regulations the Central Generator is required to achieve the operating norms over the financial year. Monthly variations can affect cash flow only, which the generator can make up at the end of the year. The generator suffers only on account of increase in working capital requirement. If the generator at the end of the year beats the norms it gets to keep the all benefits and similarly it is responsible for all the losses consequent to the failure of not achieving the norms. • If the actual availability is greater than or equal to normative availability, the generator gets allowable fixed charges (this includes RoE) irrespective of the fact whether the plant has actually been dispatched or not. • If the actual availability is greater than normative availability, there is a prorata reduction in the allowable	• Similar provisions exist for State Generators and Distribution Licensees. The Distribution Licensees can mitigate this risk by passing on this risk to the consumers either through a true up petition (at the end of the year) or through FCA (frequency as decided by SERC). The Distribution Licensee has to convince the SERC that the additional purchases where necessitated on account of reasons beyond its control. Nevertheless it increases the power purchase cost of the Distribution Licensee. • WBERC in its proposed (draft) amendment to the existing MYT regulation has proposed for graded sharing of benefits between generator and the distribution licensees. The sharing is limited to gains and not to losses.

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
fixed charges. • The Generator is entitled only to receive 25 paise per unit and energy charges (fuel cost at normative levels) for scheduled generation in excess of scheduled generation at normative PLF. • The generator is either required to pay or receive Unscheduled Interchange (UI) charges depending on the variation in the actual generation over the scheduled generation. **Beneficiary (Buyer)** • The buyer bears the risk consequent to the shortfall in the generation. In order to compensate the shortage (for each time block) the buyer has the options of approaching the short term power market, over drawal from the grid and shedding its demand. • The prices in the short term market are generally unpredictable but it has been seen that these are substantially higher than the bilateral long term prices particularly during the peak months and also during the peak hours. This may impact the financials of the buyer if the variation is high. • Variation from schedule in the Inter-State market is priced at UI charges, which are frequency linked. UI charge is as high as Rs. 10.00 per unit at 49.02 Hz, which is now proposed at Rs.10 per unit. In case of substantial overdrawl the buyer is likely to be penalized for grid indiscipline as well. • The revenue foregone on account of load shed is to the account of the buyer. • The buyer also has the opportunity to trade through short term power market or earn UI charges in case of excess availability.	

Role of Various Stakeholders

The role of various stakeholders is being discussed in the following table in order to understand to the extent to which the risk and benefits described above are contingent upon the performance of the assigned role by other stakeholders.

Central Electricity Regulatory Commission	State Electricity Regulatory Commission
• The onus of satisfying CERC that the R&M proposal is technically and financially viable is with the Generators. Generators make the upfront investment and bear the performance risk. • Beneficiaries can look into the reasonableness of the project cost and the expected operating performance. • CERC approves the cost and the operating parameters. • Govt. acts as a facilitator by providing the policy framework for undertaking R&M projects. This provides for the involvement of NTPC etc as consultant and PFC as funding agency for subsidized Interest Rates.	• The Distribution Licensees have the onus of satisfying SERCs that the proposed power procurement is based on least cost option. This requires the Distribution Licensees to evaluate financial and technical feasibility of R&M of existing plants viz a viz other supply options. • Generators are required to carry out Residual Life Assessment (RLA) and other studies in convincing Distribution Licensees of the technical and economical feasibility of the R&M project and in putting up a case before SERCs. Generator is also required to invest and carry out the R&M project. As per the existing regulations the Generators bear the risk of performance failure. • SERCs are required to look into the reasonableness of the long term procurement plan. If the R&M project provides the least cost option then the cost and the expected operating performance are approved by the Commission. • State Governments have no direct role except for providing guarantees to Financial Institutios (FIs) on behalf of State Generator for loans for R&M projects. This is crucial for financially starved State Generators.

ANNEX 2 - DETAILS OF THE MODEL

General Assumptions used for the modelling

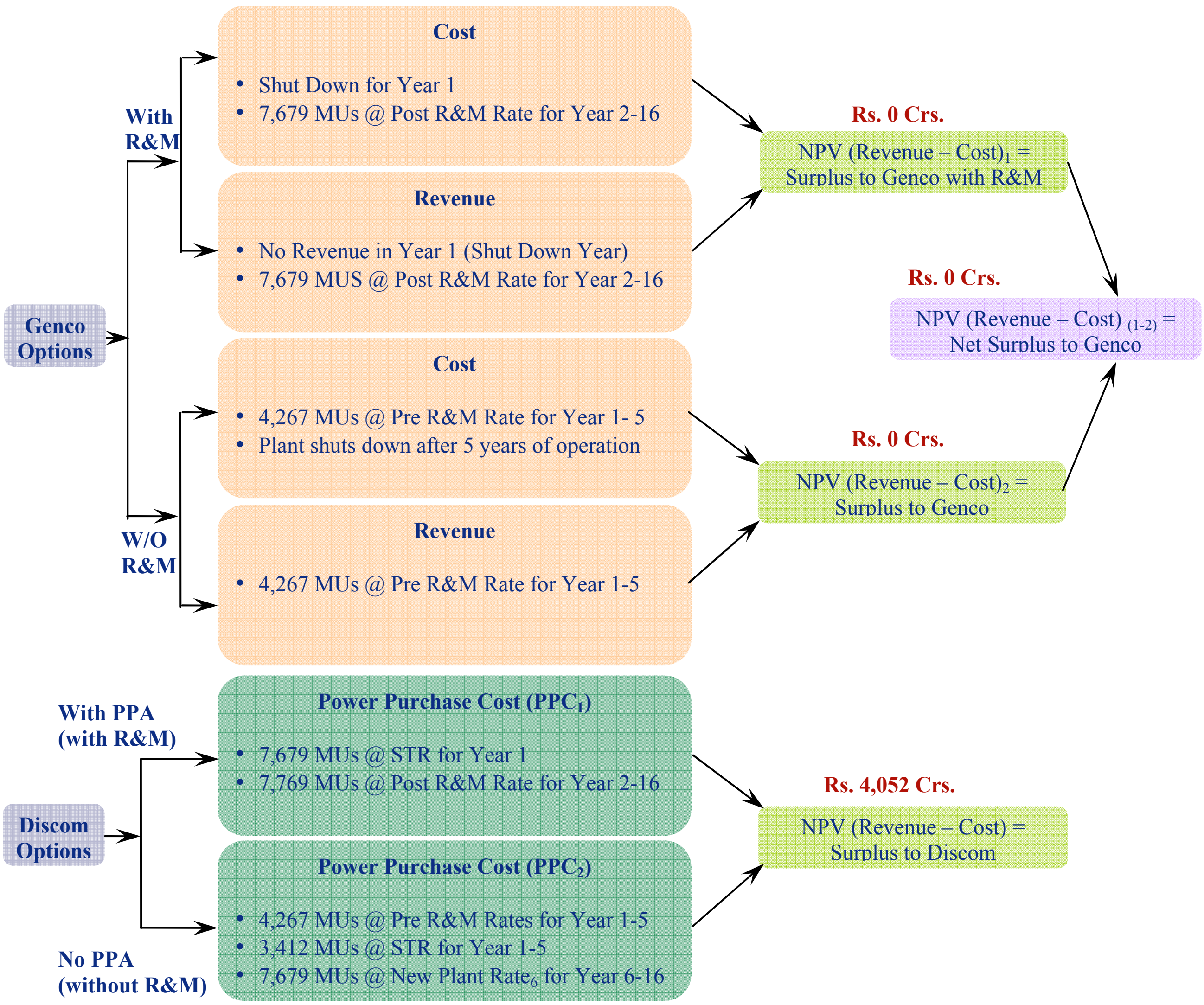
S. No.	Particulars	Unit	Pre R&M	Post R&M
	Plant Assumptions			
1	Capacity	MW	1,080	1,178
2	R & M Investments	Rs. Crs.	-	1,405
3	Station Heat Rate (SHR)	kcal / kWh	3,000	2,550
4	Plant Load Factor (PLF)	%	50%	80%
5	Auxiliary Consumption	%	9.80%	7.00%
6	Residual Life	Years	5	15
7	Generation	MUs	4,267	7,679
8	Effective Tariff (First Year)	Rs. / kWh	1.52	1.53
	Market Assumptions			
9	Short Term Power Purchase Quantity	MUs	3,412	7,679
10	Rate (First Year)	Rs. / kWh	3.50	3.50
11	Duration	Years	1 – 5	1
12	Long Term Power Purchase Quantity	MUs	7,679	-
13	Rate (First Year)	Rs. / kWh	2.32	-
14	Duration	Years	6 – 16	-
15	**Total Energy (7+9+12)**	**MUs**	**7,679**	**7,679**
16	**Total Years**	**Years**	**16**	**16**

- R&M cost has been considered as Rs. 1.3 Cr. per MW.
- The residual life of the plant under consideration for R&M has been considered as 5 years. The economic life gets extended by 10 years after R&M is carried out.
- The capital cost of a new plant has been considered at Rs.4 cr per MW.
- There would be no generation from the plant during the R&M shutdown period of 1 year.
- Deterioration in SHR Pre R&M has been considered at 2% whereas Post R&M this figure is 0.5%.
- Calorific value of raw coal has been considered at 3900 kcal/kwh at Rs. 1286 per ton.
- The inflation rate has been considered as 5.5%.
- For a new thermal plant operating and cost norms prescribed by CERC have been assumed.
- Additional purchases during shut down of the plant has been considered at short term rate similarly additional requirement during Pre-R&M phase has been met through short term purchases.
- Capacity and energy charges for all the options have been separately computed. The cost and benefit analysis for generator and Discom under various options have been done over the extended post R&M life of the project (16 years) and the analysis considers the impact of all charges and the cost of additional power purchases.

Options considered for the Model

Option 1

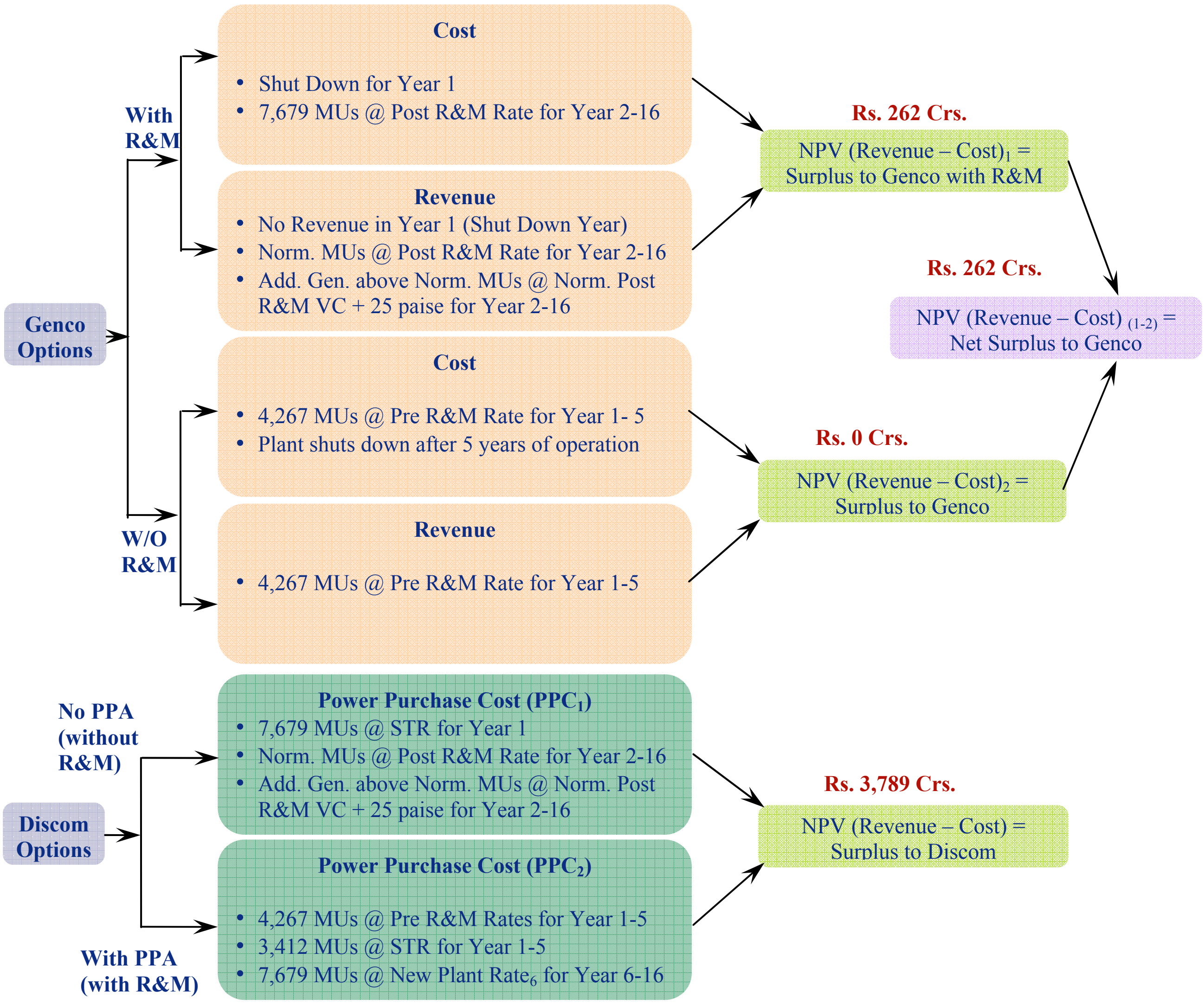
- R&M Investments
  - Proposed by the Generator
  - Approved by the Regulator
- Cost / Tariff based on Actuals
- Off take Commitment by Discoms – Up to Actual Generation
- Supply Commitment by Generators – Up to Actual Generation



Option 2 – Normative

- R&M Investments
  - Proposed by the Generator
  - Approved by the Regulator
- Tariff based on Norms; Costs Based on Actuals

Parameters	Actual	Target to be achieved in 10 years
Station Heat Rate (kcal / kWh)	2,550	2,775 - 2,653
Plant Load Factor (%)	80%	65% - 79%
Auxiliary Consumption (%)	7.00%	8.4% - 7.0%
MUs beyond target PLF		25 paise + normative variable cost



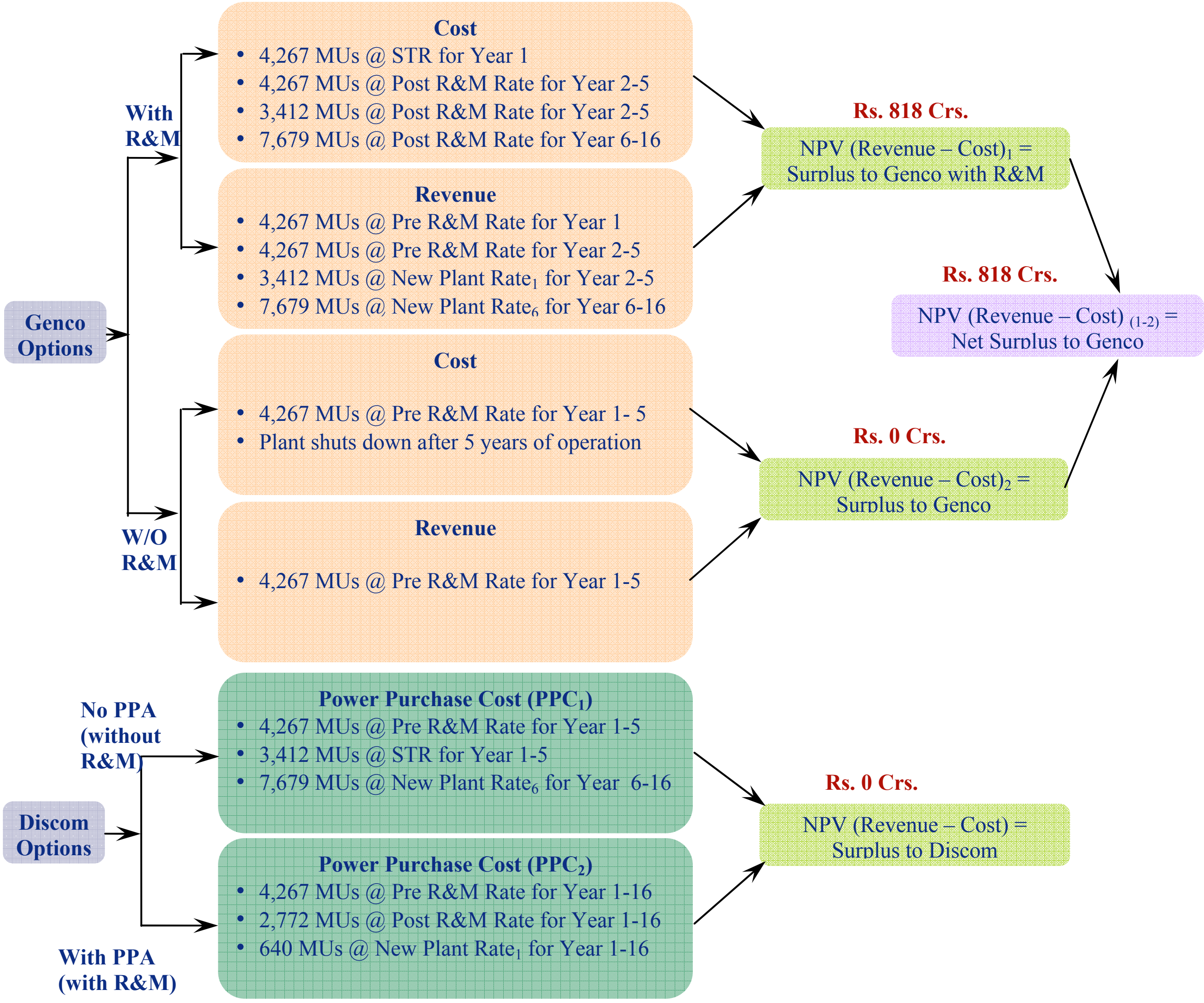
- Off take Commitment by Discoms – Up to Actual Generation
- Supply Commitment by Generators – Up to Actual Generation

Option 3 A – Market (PPA Pre – R&M)

- R&M Investments
  - Decided by Generator
  - Investment Approval from Regulator not Needed
- Tariff based on a PPA – Pre R&M Quantum, Pre R&M Rate, Pre R&M Life, Firm Supply Commitment

Parameters	PPA
Tariff (First Year)	Rs 1.52 / kWh
Quantity	4,267 MUs per Annum
Duration	5 Years

- Off take Commitment by Discoms – Up to Committed Generation
- Supply Commitment by Generators – Up to Committed Generation

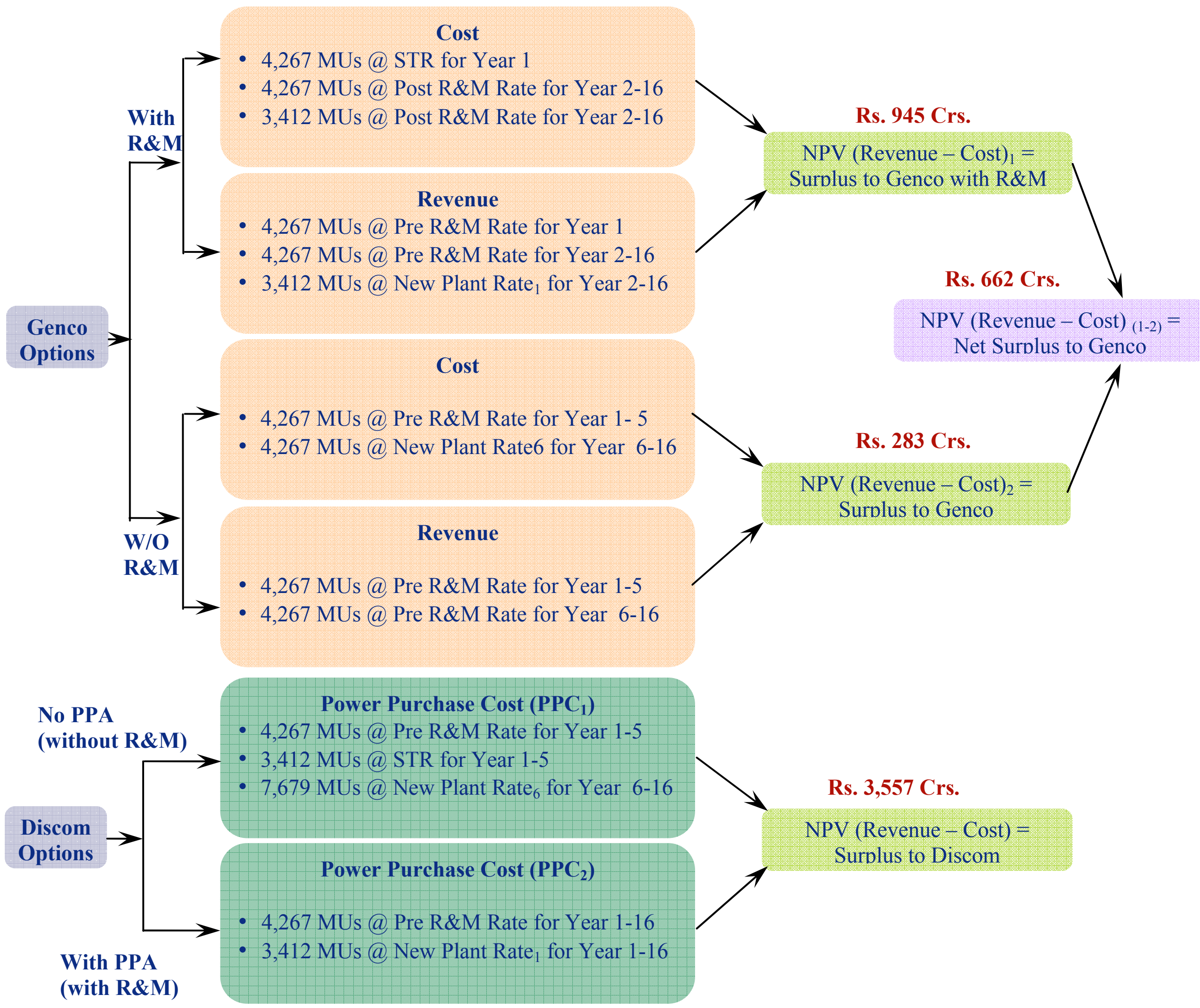

Genco Options
With R&M
Cost
• 4,267 MUs @ STR for Year 1
• 4,267 MUs @ Post R&M Rate for Year 2-5
• 3,412 MUs @ Post R&M Rate for Year 2-5
• 7,679 MUs @ Post R&M Rate for Year 6-16
Revenue
• 4,267 MUs @ Pre R&M Rate for Year 1
• 4,267 MUs @ Pre R&M Rate for Year 2-5
• 3,412 MUs @ New Plant Rate$_1$ for Year 2-5
• 7,679 MUs @ New Plant Rate$_6$ for Year 6-16
Rs. 818 Crs.
NPV (Revenue – Cost)$_1$ = Surplus to Genco with R&M
W/O R&M
Cost
• 4,267 MUs @ Pre R&M Rate for Year 1- 5
• Plant shuts down after 5 years of operation
Revenue
• 4,267 MUs @ Pre R&M Rate for Year 1-5
Rs. 0 Crs.
NPV (Revenue – Cost)$_2$ = Surplus to Genco
Rs. 818 Crs.
NPV (Revenue – Cost)$_{(1-2)}$ = Net Surplus to Genco
Discom Options
No PPA (without R&M)
Power Purchase Cost (PPC$_1$)
• 4,267 MUs @ Pre R&M Rate for Year 1-5
• 3,412 MUs @ STR for Year 1-5
• 7,679 MUs @ New Plant Rate$_6$ for Year 6-16
With PPA (with R&M)
Power Purchase Cost (PPC$_2$)
• 4,267 MUs @ Pre R&M Rate for Year 1-16
• 2,772 MUs @ Post R&M Rate for Year 1-16
• 640 MUs @ New Plant Rate$_1$ for Year 1-16
Rs. 0 Crs.
NPV (Revenue – Cost) = Surplus to Discom

Option 3 B – Market (PPA Extended Life of Plant)

- R&M Investments
  - Decided by Generator
  - Investment Approval from Regulator not Needed
- Tariff based on a PPA – Pre R&M Quantum, Pre R&M Rate, Pre R&M Life, Firm Supply Commitment

Parameters	PPA
Tariff (First Year)	Rs 1.52 / kWh
Quantity	4,267 MUs per Annum
Duration	16 Years

- Off take Commitment by Discoms – Up to Committed Generation
- Supply Commitment by Generators – Up to Committed Generation

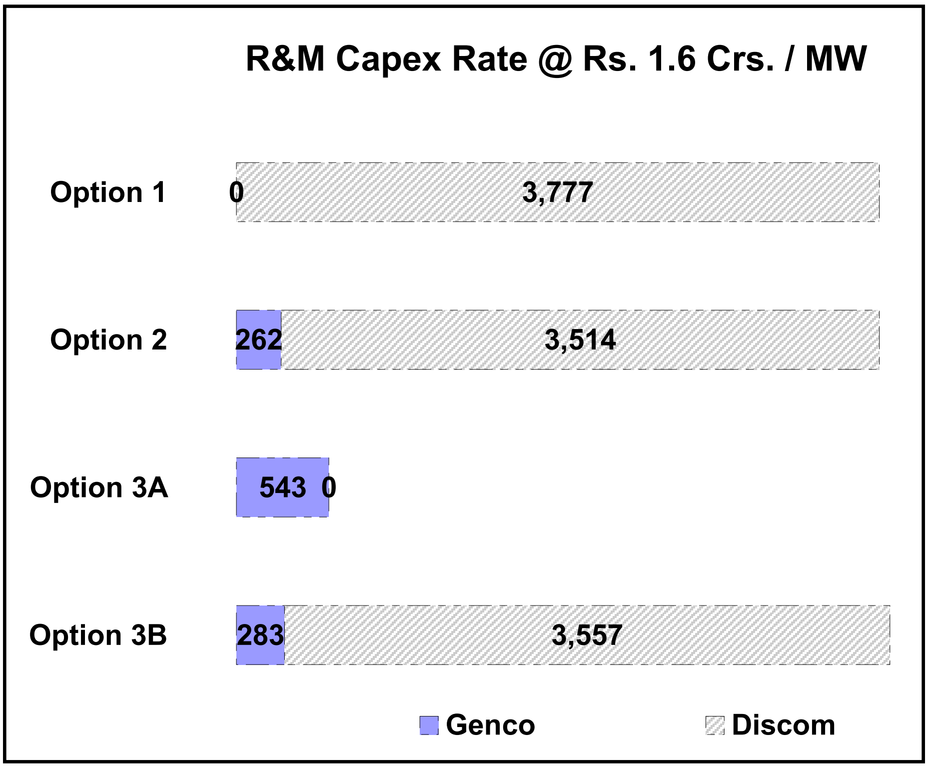


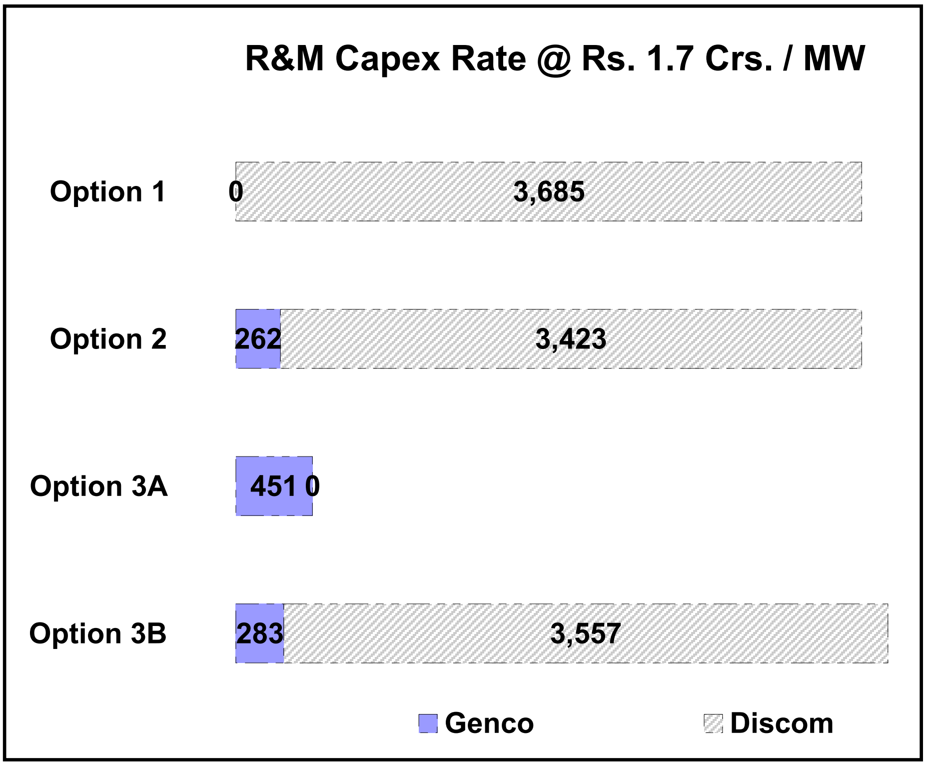
Sensitivity of the outcomes to variation in the assumed R&M cost

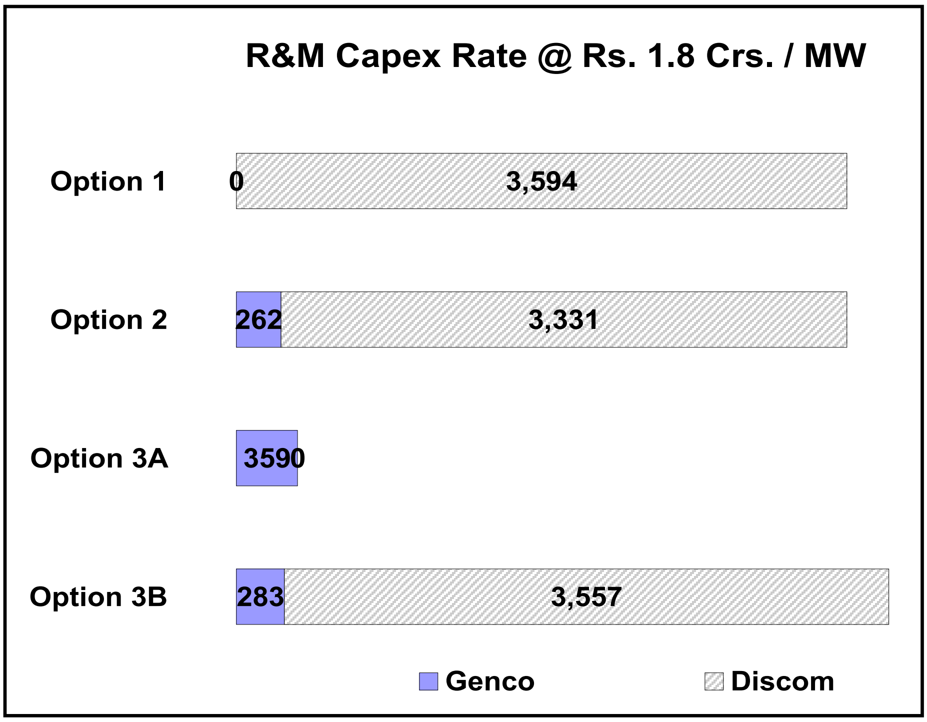
During discussions with various stakeholders it became very obvious that it is difficult to benchmark the R&M cost as it is unit and site specific. The actual cost can be known only after the plant has been opened for capex. A sensitivity analysis on R&M cost has been done by varying the capex cost in steps of Rs. 0.1 Cr per MW. The relative attractiveness of the options as discussed above does not change. The outcome of the sensitivity analysis is given below:

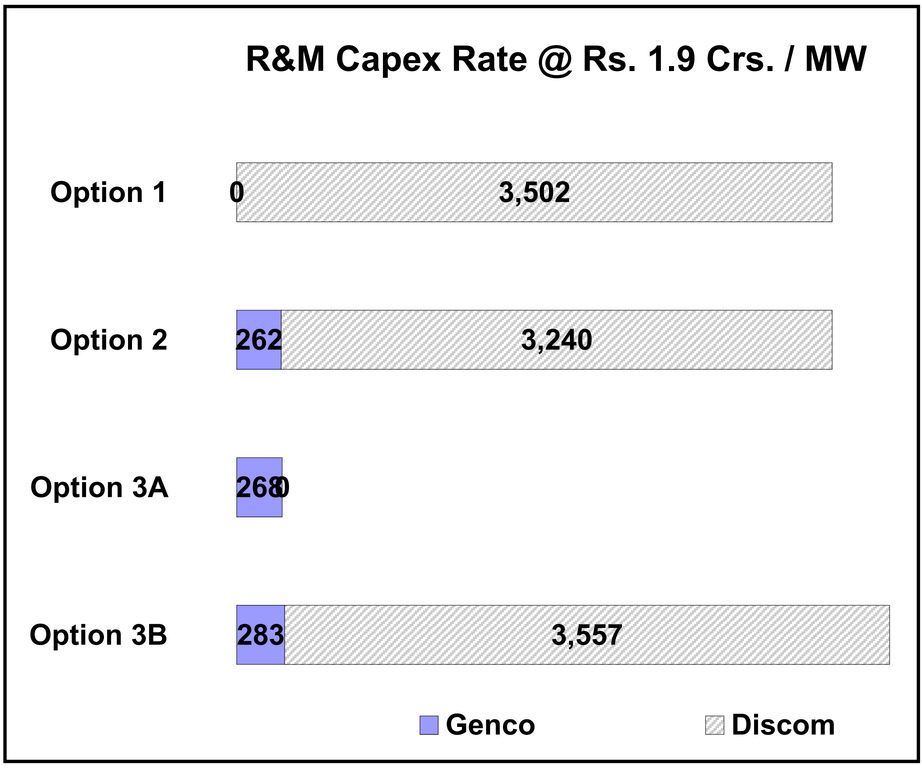
Summary – Impact of Energy Efficient Renovation and Modernisation on Generator & Discom

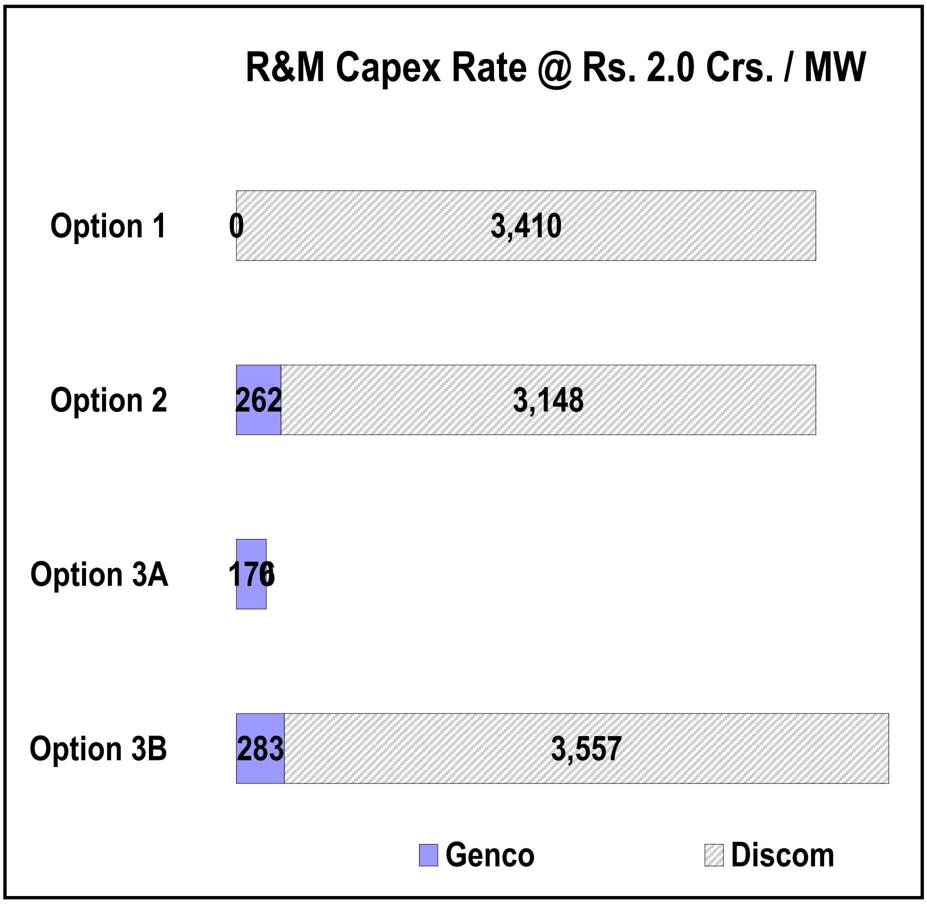
(All figures are in Rs. Crs. unless specified)






R&M Capex Rate @ Rs. 1.8 Crs. / MW
Option 1
0
3,594
Option 2
262
3,331
Option 3A
3590
Option 3B
283
3,557
Genco
Discom


R&M Capex Rate @ Rs. 1.9 Crs. / MW
Option 1
0
3,502
Option 2
262
3,240
Option 3A
2680
Option 3B
283
3,557
Genco
Discom


R&M Capex Rate @ Rs. 2.0 Crs. / MW
Option 1
0
3,410
Option 2
262
3,148
Option 3A
176
Option 3B
283
3,557
Genco
Discom

ANNEX 3 - TECHNICAL BARRIERS TO BE ADDRESSED

Technical barriers – improved energy accounting and base-lining are a prerequisite

As well as other barriers to investment, technical barriers need to be addressed. These barriers are listed below.

- Information asymmetry on technical issues is a barrier to appropriate evaluation of improvement opportunities
- Measurement: **Disaggregation of losses** chain helps focus on the problems that can be addressed (see below).
- Planning: **Asset management** plan is required to ensure optimal capacity and heat rate
- Collaborative approach could lead to better outcomes
- **Evaluation: Identification of range of possibilities**, inter-se evaluation of costs-benefits-risks, and prioritisation
- **Target setting**: Based on prioritised options; recognise level of performance corresponding to what is already being paid for, and the additional performance – additional payment linkage
- **O&M practices** to achieve and sustain the plans
- **Build institutional capacity**, where required, to do all of this

Measurement: Disaggregation of losses chain helps focus on the problems

Item	Design Value/Target	Actual Value/Target	Comment
Fuel			
Fuel Quality			
Stock Deficit/Surplus			
Boiler			
Dry Flue Gas Loss			
Moisture Loss			
Carbon in FBA/PFA			
Radiation and Unaccounted			
Other key boiler operating parameters – Pressure, S/HT and R/HT Temperature (if applicable), S/T and R/HT Attemperator Flow etc			
Steam Water Cycle			
Condenser Loss			
Final Fed Temperature			
Make Up loss			
Turbine			
Cylinder Efficiencies			
HP			
IP			

LP			
etc			

Asset Management Plan

To assess the Generator's Asset Management capability O&M Plans should be required that relate to performance and improvement plans for the site. They should be required to forward a detailed plan similar to that required now but with more technical detail.

The Plan should set out in sufficient detail the following information
Vision - A short statement of the Generator's vision of the future.

Operation Plan

- Key areas of operational performance, particularly
- Availability and Thermal Efficiency and initiatives in these and other operational areas which are necessary or desirable to maintain or improve performance.

Maintenance Plan

- Maintenance proposals for the plan period.

Investment Plan

- Description of all proposed capital investments and major repair or rehabilitation work accompanied by an outline investment appraisal including an analysis of risks, costs, benefits and economic return.

Evaluation: Range of possibilities, inter-se evaluation of costs-benefits-risks, and prioritisation

Item	Cause of loss	R&M works	Benefit	Estimated Cost	Risk
Fuel					
Fuel Quality	Low CV	Additional milling capacity and improved design	Medium	High	Medium
	High Moisture	Minimise as delivered and stock moisture - due to monsoon, washing or dust suppression	Medium	Medium / High	Medium
Boiler Loss					
Dry Flue Gas Loss	Air heater Blockage	Replace Elements	Medium	Medium / Low	Low
	Air heater Seal Leakage	Replace Seals and Dampers	Medium	Low	Low
	High Gas exit temperature	Improve soot-blowers	Low	Low	Low
	High Gas Flow	Furnace and Duct Leaks – repairs	Low	Low	Low

Item	Cause of loss	R&M works	Benefit	Estimated Cost	Risk
Carbon in FBA/PFA Loss	Poor Mill Grinding throughput	Replace or Overhaul Mills	Medium	Medium / High	Low
	Low PF Temperature	Modify Air Heater - see above		Medium / High	Medium
	Poor Combustion	Fit renew or overhaul new PF classifiers	Medium	Medium	Medium
	Poor Combustion	Improve PF Distribution	Medium	Medium	Medium
	Poor Combustion	Improve PF Burners	Medium	Medium / High	Medium
	Lack of Combustion Air	Fan performance, (Airheater see above	Medium	High	Medium
Radiation and Unaccounted Loss	Poor Lagging	Repair /replace lagging	Low	Low	Low
Superheat Pressure Loss		Improve boiler design, improve combustion performance (see Carbon in PFA above)	Low	High	High
	Passing valves	Repair/replace valves	Low	Low	Low
Superheat Temperature Loss	Poor combustion, poor design	Improve boiler design, improve combustion performance	Medium	High	High
Reheat Temperature Loss	Poor combustion, and design	Improve boiler design, improve combustion performance	Medium	High	High
Steam Water Cycle					
Condenser Vacuum Loss	Air Ingress	Reduce Air Leakage	High	Low	Low
		Improve Air Pump Performance – renew /repair	High	Low	Low
	CW Flow Low	Fit tube cleaning equipment (taprogge)	Medium	Low	Low
	CW Flow Low	Additional off load cleaning	Medium	Low	Low
	CW Flow Low	Repair/replace CW pumps	Low	Medium / High	Medium
	CW Temperature High	Improve Cooling Tower performamce (if fitted) – new packs etc	Low	Medium / High	Medium
	CW Temperature High	Fit additional CT	Medium	High	High
Final Feed Temperature Loss	Heater OOS – tube leaks	Replace heater	High	Medium	Low
	Heater Bypassing	Repair valves and baffles	Medium	Low	Low
Make Up loss	MU Water Quality	WTP modifications to ensure correct quality	Low	Low	Medium
		Reduce Condensate Contamination – renew condenser	Medium	High	Low
		Reduce Condensate Contamination – repair condenser	Low	Medium/Low	Low

Item	Cause of loss	R&M works	Benefit	Estimated Cost	Risk
		Improve chemical monitoring -Optimise blowdown regime	Low	Low	Low
	Passing Valves	Repair /replace valves, levels controls etc	Low	Low	Low
	Sootblowing	Optimise sootblowing regime	Low	Low	Low
Turbine					
HP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low
IP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low
LP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low

Target setting: Based on prioritised options

Table shows types of works that will make an improvement in energy efficiency at each level of progressively worse heat rate.

	1	2	3	4	5
Heat Rate	2500-2550 (kcals/kWh)	2550-2600(kcals/kWh)	2600-2650 (kcals/kWh)	2650-2700 (kcals/kWh)	>2700 (kcals/kWh)
Cost Category	Capital Investment to cover restabilising performance norms	Capital Investment or Normal O&M Expenditure –	Normal O&M Overhaul Expenses	Normal O&M Expenses and Practices	Normal O&M Expenses and Practices
Comment	Cost/Benefit Analysis too agree way forward	Cost/Benefit Analysis to agree way forward	Regulator expects Generator to improve O&M	Regulator expects Generator to improve O&M	Regulator expects Generator to improve O&M
Type of Work	Major Turbine Overhaul Feed Hear Renewal Major Milling Pant Repacement	Condenser Tube Cleaning Equipment	Improvement in Milling Plant Maintenance	Reduction in Make Losses Improvement in Air Heater and Boiler Sealing Maintenance	Reduction in Condenser Air Leakage

O&M practices to achieve and sustain the plans

- Clear O & M policies, principles and procedures

- Clear objectives and targets and other key performance indicators
- Implementation of appropriate monitoring mechanisms (and potentially to regulatory reporting requirements)
- Optimum O & M organisation structures with the correct resources, skills and competence to deliver the objectives; third parties to be used where required and where economically viable
- Robust 5 year business plans and detailed annual operating plans and budgets for each station.
- A detailed asset management plan
- A proactive approach to engineering risk management and assessment
- A proactive approach to planned, preventative and breakdown maintenance
- The introduction of detailed engineering plant status plans
- The introduction of best practice plant condition monitoring
- Best practice evaluation of spares and stores holdings
- A proactive monitoring, auditing and review process

ANNEX 4 - RELEVANT POLICIES AND REGULATIONS, RECORD OF STAKEHOLDER PERCEPTIONS AND BARRIERS IDENTIFIED

Introduction

This Annex sets out the findings of Part 1 of the project, comprising the Inception Report and Diagnosis, as follows:

- A description of the broad electricity policy, legislative and planning and regulatory framework in India, in so far as it is relevant to EE R&M;
- A description of the applicable regulatory rules, with specific reference to CERC regulations and to regulations made by the regulatory authorities in Maharashtra, West Bengal and Uttar Pradesh;
- The perspective of stakeholders, based on an extensive series of interviews held in India in early and mid-December;
- The main barriers to EE R&M identified by our team;

Policy, Legislative, Regulatory and Planning Framework

The Electricity Act 2003

The Electricity Act 2003 is the primary legislative instrument governing the electricity supply industry in India. It requires:

- that the Central Government shall prepare, from time to time, a national electricity policy and a tariff policy in consultation with State Governments and the Central Electricity Authority (CEA); and
- the CEA to prepare and notify a National Electricity Plan (NEP) every five years, in consultation with stakeholders and in a form consistent with the National Electricity Policy, with the approval of and subject to such revision as the Central Government may direct.

The Act specifically provides that electricity generation shall be an unlicensed activity. However, generation is still subject to certain regulatory controls provided by the Act, as follows:

- to comply with grid connectivity standards specified by the CEA
- to notify the technical details of its plant to the CEA and the appropriate regulatory commission;
- to co-ordinate with the appropriate transmission utility in relation to the transmission of electricity generated (in particular for load despatch purposes);
- that the appropriate Government may issue directions to generating companies in exceptional (emergency) situations;

- that the appropriate regulatory commission may issue directions to a generator, in the event that it believes the company is abusing a position of dominance in the market, or is party to an agreement likely to cause an adverse effect on competition in the market;
- that the appropriate regulatory commission shall determine the tariff chargeable by the generating company (see further detail below).

Certain additional provisions also apply to hydro-electric plant and to captive generating plant (effectively self-supply).

The Act sets out the functions and duties of the CEA, including the requirement to formulate the NEP and to advise generating companies on matters that enable them operate in "an improved manner."

It establishes a Central Electricity Regulatory Commission (CERC), with the function of regulating the tariff of generating companies owned by the Central Government and those with a "composite scheme for generation and sale of electricity in more than one state." The CERC is also responsible for advising the Central Government on:

- the National Electricity Policy and the Tariff Policy;
- the promotion of competition, efficiency and economy in the industry; and
- the promotion of investment.

It also provides that the States must establish regulatory commissions with the function of determining tariffs for electricity supplied by generators to distribution companies, as well as regulating electricity purchases made by distribution companies. In carrying out these functions that state commissions are to be "guided by" the National Electricity Policy, the National Electricity Plan and the Tariff Policy. State regulatory commissions are also required to advise the State Government on the promotion of competition, efficiency and economy in the electricity industry.

In relation to generation tariffs the Act provides that regulators are required to be "guided by:"

- the principles adopted by the CERC;
- the need for generation to be conducted according to commercial principles;
- the encouragement of competition, efficiency, the economical use of resources, good performance and optimum investment;
- the need to reward efficiency in performance;
- multi-year tariff principles;
- the need to move towards cost reflectivity; and
- the National Electricity Plan, National Electricity Policy and the Tariff Policy.

In situations of shortage the Act stipulates that the appropriate Commission may set maximum and minimum tariffs for a period no longer than one year.

Furthermore, where there has been a transparent bidding process, in accordance with guidelines issued by the Central Government, the tariff resulting from the bidding process shall be adopted by the appropriate Commission.

The Act provides that appeals against orders made by Regulatory Commissions may be made to an "Appellate Tribunal." In certain circumstances appeals against a decision made by a Tribunal may be made to the Supreme Court.

Thus, it is clear that the Act provides a framework under which Regulatory Commissions are expected to take account of measures that promote energy efficient operation and maintenance practices in generation plant. This includes measures to reward generators that improve energy efficiency (including through renovation and modernisation programmes) through the creation of incentives.

In addition, as a result of the purchasing obligations of distribution licensees (merit order and least cost approaches) state regulators, in pursuance of their general duty to be guided by the principles of efficiency, the economical use of resources, good performance and optimum investment, can encourage inefficient generators to adopt energy efficient R&M where this would displace more expensive short term and imported generation.

Energy Conservation Act 2001

The Energy Conservation Act 2001 contains provisions relating to the promotion, efficient use and consumption of energy. It designates Thermal Power Stations, Hydro-Electric (sometimes referred to in India as Hydel) Power Stations, Transmission Companies and Distribution Companies as "Designated Consumers" and provides that these may be subject to certain directions from the Central or State Government, as follows:

- the Central Government can direct energy intensive/designated consumers to commission an energy audit from an accredited Energy Auditor;
- the Central Government can direct designated consumers to take action on the report of the Energy Auditor;
- the Central Government can direct a Designated Consumer who does not fulfil certain prescribed energy consumption norms to prepare a scheme for achieving these norms;
- the State Government can direct a designated consumer to commission an energy audit done from an accredited Energy Auditor.

Non-compliance with such directions may result in the imposition of a financial penalty.

Importantly the Act empowers the Central Government to prescribe energy consumption norms for electricity generating companies and to force inefficient companies to "take appropriate measures" to increase energy conversion efficiency in their operations.

Electricity policy

Electricity policy in India is determined by the Government of India, in accordance with the provisions of the Electricity Act 2003 and in consultation with State Governments, the CEA, the CERC and other stakeholders. The existing National Electricity Policy (NEP) was published in the Gazette of India on 12 February 2005.

At the highest level the present electricity policy provides that the availability, reliability and quality of power supply "to Indian industry" is an equal goal to the provision of supply to rural customers.

The policy also provides that the CEA shall develop a National Electricity Plan in consultation with State Governments and other stakeholders. This document should have a 5 year time-frame and also take into account a longer term (15 year) horizon in a "perspective plan".

Both the Central and the State Electricity Regulatory Commissions, while determining tariffs in accordance with the powers set out in the Electricity Act, are required to take guidance from the National Electricity and National Tariff policies. The National Tariff Policy is summarised in the following section of this Annex.

Against a background of rapidly increasing demand the policy sets out the following key objectives for the generation sector:

- to add 100,000MW of new capacity in the period 2002-12;
- to enhance the availability of installed capacity to 85%; and
- to create a spinning reserve margin of 5%.

The policy notes that coal fired power stations will continue to make a significant contribution to India's power supply and that coal will "necessarily remain the primary fuel." It also notes that:

- "renovation and modernization for achieving higher efficiency levels needs to be pursued vigorously and all existing generation capacity should be brought to minimum acceptable standards. The Government of India is providing financial support for this purpose.
- for projects performing below acceptable standards, R&M should be undertaken as per well-defined plans featuring necessary cost-benefit analysis. If economic operation does not appear feasible through R&M, then there may be no alternative to closure of such plants as the last resort.
- in cases of plants with poor O&M record and persisting operational problems, alternative strategies including change of management may need to be considered so as to improve the efficiency to acceptable levels of these power stations."

In relation to financing of necessary investments (including in EE R&M) the policy states:

- "all efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of consumers' interests on the one hand and provide motivation for improving the efficiency of operations on the other; and

- competition will bring significant benefits to consumers , in which case, it is competition which will determine the price rather than any cost plus exercise on the basis of operating norms and parameters. All efforts will need to be made to bring the power industry to this situation as early as possible, in the overall interest of consumers. Detailed guidelines for competitive bidding as stipulated in section 63 of the Act have been issued by the Central Government."

In relation to energy efficiency measures the policy encourages the establishment of coal washeries that should enhance the efficiency of coal fired power stations and other large coal fired combustion plant.

In relation to the need for a co-ordinated development the policy notes that:

- "the State Governments need to ensure the success of reforms and restoration of financial health in distribution, which alone can enable the creation of requisite generation capacity".

In summary therefore the National Electricity Policy:

- requires R&M to be pursued for poorly performing plant, where justifiable on the basis of cost-benefit analysis. However it gives neither the CERC, nor state regulators, nor State generating companies, a direct responsibility to ensure that R&M projects are pursued;
- suggests that performance norms, together with incentives and disincentives will need to be developed, whilst opining that competition will bring consumer benefits and determine prices more effectively than any form of cost plus exercise or operating norm; .
- hints somewhat obliquely that closure or change of management may be necessary for plant with a poor record and persisting problems, without commenting on the practical difficulties of achieving this in a market characterised by shortages of power and affordability problems; and
- notes that a financially healthy distribution sector is essential to the development of sufficient generation capacity (through both new build and R&M measures).

In summary the NEP imposes somewhat stronger requirements in relation to EE R&M than the Electricity Act or the Energy Conservation Act, because it requires that "renovation and modernization for achieving higher efficiency levels needs to be pursued vigorously."

National Tariff Policy

The National Tariff Policy was published in the Gazette of India on 6 January 2006 in accordance with the provisions of the Electricity Act 2003. It aims to establish a consistent basis for the determination of generation tariffs throughout India (amongst other things) whilst meeting the twin objectives of attracting sufficient investment to meet demand and protecting the interests of consumers by ensuring that tariffs are reasonable.

The policy stipulates that all future power requirements are sourced through a competitive bidding process except:

- if the additional power results from the expansion of an existing project (which we believe includes all potential EE R&M projects); or
- if a State owned/controlled company is the developer (which is also likely to include all potential EE R&M projects) in which case "regulators will need to resort to tariff determination based on norms."

However, the above exceptions are also subject to the requirement that all new projects (both private and public sector) should be based on competitive bidding within 5 years (i.e. by 2011) or by such date as the regulatory commission is confident that it is appropriate to introduce competition.

Norms are to be set by the Central Commission, in consultation with the Central Electricity Authority. State regulatory commissions are expected to be "guided by" these norms. We have reviewed below only the norms relating to operating performance and not those relating to the balance of equity and debt, depreciation rules, or other elements of project financing. Norms applicable in Maharashtra, Uttar Pradesh and West Bengal are considered further in the following section of this Annex.

- ***Renovation and Modernisation:***

  The policy states that renovation and modernization needs to be encouraged, but that it must not include periodic overhauls.

  Consistent with the overall objectives, it states that a multi-year tariff (MYT) framework may be prescribed. This should also cover capital investments necessary for renovation and modernization and an incentive framework to share the benefits of efficiency improvement between the utilities and the beneficiaries. As part of this process revised and specific performance norms may be fixed by the appropriate State Regulatory Commission.

  Appropriate capital costs required for pre-determined efficiency gains and/or for sustenance of high level performance would need to be assessed by the appropriate regulatory commission.

- ***Unscheduled interchange payments***

  The tariff policy requires state regulators to implement an unscheduled interchange scheme for intra-state power transfers (this is described in later section this Annex.

- ***Benefits under CDM***

  Tariffs for all electricity projects that result in lower Green House Gas (GHG) emissions than the relevant base line should take into account the benefits obtained from the Clean Development Mechanism (CDM) in a manner designed to provide adequate incentive to project developers.

National Plan and National Electricity Plan

As outlined above the Electricity Act 2003 requires that the CEA should "prepare a National Electricity Plan (NEP) every five years, in consultation with stakeholders and in a form consistent with the National Electricity Policy."

This plan should set out in detail various schemes/projects to be undertaken in generation, in order to meet projected demand in the next five year plan and in the subsequent two five year plans, which are reviewed on a "perspective" basis. It would also provide a framework for co-ordination between various agencies/players in the power sector.

The electricity sector is also a key element of India's National Plan, produced by the Planning Commission, with the current National Plan (the 11th Plan) covering the period 2007-2012.

The CEA's review of the electricity section of the National Plan notes that Phase I of the Govt of India's R&M programme was launched in September 1984 and was successfully completed. Later, a Phase II programme commenced in 1990-91 for R&M of 44 power stations, with financial support provided by the Central Government's Power Finance Corporation, based on schemes identified by CEA, utility companies and BHEL (an Indian engineering contractor). For the 9th Plan (1997-2002) 29 power stations were identified for R&M, with life extension works completed at a further 25 units.

The 10th National Plan and the 11th National Plan both identified significant R&M and life extension programmes in order to help meet India's power supply shortage and these are briefly reviewed in turn below. Life extension works present a considerable opportunity for major EE R&M works to be carried out, but during the 10th and 11th Plans it has not been a specific requirement that EE R&M works should accompany a Life Extension programme. Nevertheless it is useful to review the level of activity as this provides an indication of the incentive for LE works and the project management capabilities of the Gencos.

- ***10th National Plan (2002-7)***
    - **Performance enhancement/sustenance**

      The plan identified 57 comparatively new units at 13 power stations, with a total capacity of 14,270 for R&M works to sustain/improve their performance. This comprised 53 units with a capacity of 200MW or greater and 4 units with a capacity of 200MW or less (including only 2 units with a capacity less than 100MW). The average capacity of these units at commencement of the plan was 250.4MW. Almost half (25) of the units identified and a little over half of the capacity (7460MW) are owned by NTPC.

      The average age of these units at commencement of the plan was 15.9 years.
    - **Life extension**

      The 10th National Plan (2002-7) identified 106 units at 32 power stations, with a total capacity of 10,413MW and an average load factor of 49% (before the programme) for life extension works and capacity recapture/uprating through comprehensive R&M schemes.

This comprised only 12 units with a capacity of 200MW or greater, compared with 94 units with a capacity of less than 200MW (including 53 units with a capacity of less than 100MW – before upgrading). As a result of the planned upgrade the total capacity of the units was due to increase from 10,413MW to 10,747MW, a small but significant contribution to India's total capacity shortfall. The average capacity of these units at commencement of the plan was 98.2MW.

Commissioning of this plant varied substantially, with the oldest plant commissioned in 1953 and the most modern commissioned in 1987. None of the plant identified for life extension was owned by NTPC at the time the plan was prepared. The average age of these units at commencement of the plan was 29.2 years.

Unfortunately it appears as though the programme was not an overwhelming success. At the end of 2006 CEA figures indicate that works had been completed, were in process or had been ordered at 33 units, representing 5,338MW (51%) of the total 10,413MW of plant identified for R&M/LE works and with an average size of 162MW. Work at a further 24 units, representing a further 1,418MW of mostly small units, with an average size of 59MW and an average age of 33.8 years had been found to be economically non-viable. The residual units have either been transferred to the PiE programme (see below) or were noted as "expected to be completed" during the 11th Plan.

Annex 4, Table 1 – LE works completed, declared non-viable or carried forward from 10th National Plan. Based on CEA figures for the period to December 2006.

10th Plan	***LE completed/in progress/works ordered***	***Non-viable***	***Residual/ held over***
Average plant age	*26.7 years*	*33.8 years*	*28.6 years*
Average capacity	*114.5MW*	*59MW*	*106.4MW*

Table 1 of this Annex (above) compares the average age and capacity of units identified in the 10th Plan as suitable for LE works. It can be seen that the average size of plant where works were completed was slightly higher than for units where work was held-over to the period of the 11th Plan and that the average age was also slightly lower. In both the case of units where works were completed/in progress and units where works were carried over, average unit size was significantly higher than for units declared non-viable, whilst average unit age was also significantly lower.

In the case of units found to be non-viable it is notable that for only one station (2 units) were the turbine manufacturer and boiler of the more common BHEL or LMW manufacture. This may indicate that replacement parts or refurbishment are more feasible at the present time for BHEL/LMW units, although we have not carried out a detailed study of this issue.

Annex 4, Table 2 – generating companies participating actively in the 10th Plan and where LE works have been completed, are in progress, or have been ordered Based on CEA figures for the period to December 2006.

Generating Company	Number of units
Chhatisgarh State Electricity Board (CSEB)	4
APGenco	3
Punjab State Electricity Board (PSEB)	4
Tamil Nadu State Electricity Board (TNEB)	5
Uttar Pradesh (UPRVUNL)	12
Gujarat (GSECL)	2
Haryana (HPGCL)	1
Mahdya Pradesh Electricity Board (MPEB)	2

A further indicator of the success of the programme would be an indication that the programme is being taken up by a large number of generating companies. However, this may not give an entirely clear picture as it would be expected that take up would also reflect the profile of each company's generation portfolio.

As Table 2 of this Annex indicates the programme has been actively taken up by a number of state generating companies, especially Uttar Pradesh. There has been a slower uptake by Mahagenco and West Bengal Power Development Corporation.

- ***Partnership in Excellence Programme***

To support the activities of the 10th Plan (and subsequent plans) the CEA drew up a "Partnership in Excellence" programme designed to improve the performance of plant with a low load factor, to the National Average (in 2006/7 around 77%). As a first step, 26 low performing stations were targeted for stabilisation to bring their load factor to an optimum (60%) level through improved O&M practices and performance of energy audits and then to 65% through procurement of essential spares and improved R&M. Finally they will be considered for comprehensive capital overhaul, if this is techno-economically viable.

Through the programme the plant owners may sign a "Partnership in Excellence" agreement with the National Thermal Power Corporation (NTPC) or with another better performing utility, or they may decide to improve performance through "Self O&M" practices.

In reviewing progress with the PIE the CEA 2006-7 Thermal Performance Review notes that of the 26 stations identified for stabilisation, 17 had signed an agreement with NTPC, 1 had signed an agreement with Tata Power, 4 have opted for self-improvement and 4 were found to be no longer economically viable.

The Thermal Performance Review also notes that 13 stations (a figure consistent with the plant identified for performance enhancement/sustenance in the 10th plan) showed an improvement in their thermal performance, with a load factor increase from 43.8% to 60.3%.

- ***11th National Electricity Plan (2007-12)***

  - **Performance enhancement/sustenance**

    31 thermal units, with a capacity of 7090 MW, are expected to be taken up for an R&M Programme to sustain/improve their performance. This comprises 29 units at 210MW, originally commissioned between 1986 and 1997 and 2 units at 500MW, originally commissioned in 1991 and 1992. The average capacity of these units at commencement of the plan was 228.7MW and the average age was 17.3 years. None of this plant was owned by NTPC at the time the plan was prepared.

  - **Life extension**

    In addition 34 thermal units with a total capacity of 6000 MW were identified for life extension and capacity uprating. This includes 9 units at 120MW or below, originally commissioned between 1966 and 1985 and 25 units at either 200MW or 210MW, originally commissioned between 1979 and 1989. The average capacity of these units at commencement of the plan was 176.5MW and the average age was 26 years. None of this plant was owned by NTPC at the time the plan was prepared.

    In addition, a total of 28 units, comprising 3012.5MW identified for LE under the 10th Plan, but where orders for LE have not yet been placed, are expected to be completed during the period of the 11th Plan.

Annex 4, Table 3 – average age and size of units identified for life extension and R&M performance enhancement in the 10th and 11th Indian National Electricity Plans.

	10th plan LE*	**10th plan R&M**	**11th plan LE**	**11th plan R&M**
Average plant age	29.2 yrs	15.9 yrs	26.0 yrs	17.3 yrs
Average capacity	98.2MW	250.4MW	176.5MW	228.7MW

Table 3 of this Annex indicates the difference in unit age and capacity in those units identified for LE or R&M works in the 10th and 11th plans. It is notable that plant age in the 11th plan decreases slightly, compared with the 10th plan, whilst the average unit size increases for LE works, but decreases for R&M works. This may reflect the retirement of a range of mostly small units during the 10th plan (as described above).

Policy for private sector participation in R&M

This policy dates from 28th Oct 1995 and is therefore quite old. As a result it should be read in conjunction with subsequent amendments, the Electricity Act 2003 and the Order of the Appellate Tribunal for Electricity dated 6th June 2007 (which provides that the CERC now has responsibility for decisions with tariff implications). A brief summary of the main provisions is set out below.

- ***Economic justification***

  The policy advocates private participation in R&M for the following reasons:

  - relative economics: in privatised R&M, risks due to time & cost over runs, plans & designs, operational risks and shortfall in realising target improvements are transferred to the private sector;
  - financing of other priorities: private sector involvement will reduce calls on limited public sector finances and could, in some circumstances, generate resources for investment in other priority areas, such as system upgrade and improvements in metering; and
  - cost reflectivity of energy prices: the higher costs of private finance will be reflected in energy prices and, by providing a closer reflection of real current costs, competitively derived prices of privatised R&M can help eliminate hidden subsidies that are detrimental to efficient market functioning.

- ***Options identified***

  Three options are suggested for undertaking R&M of a generation plant

  - **Option 1: Lease, rehabilitate, operate and transfer (LROT)**

    Under this option, the private promoter (PP) would take over the power station on a long-term lease, invest and carry out the R&M of the power station and take over its operation and maintenance. Normally, the station would revert back to the owner on completion of the lease period, but could potentially be renewed;

  - **Option 2: Plant sale**

    The plant owner (State Electricity Board – now Genco or equivalent) would offer for sale power stations that they felt were uneconomic for them to run and difficult to maintain. The private promoter could have two options: either to sell the electricity generated on a captive basis, or to sell the electricity generated to the local distribution company.

  - **Option 3: Joint venture**

    In this option, a new company would be formed as a joint venture (JV) between the owner (SEB/Genco) and a chosen selected private sector partner. In this case the JV Company would undertake the R&M and own, operate and maintain the power station in question. The private sector partner would normally assume responsibility for management of the JV.

    The participation of the owner (SEB/Genco) would be through transfer of the plant at an agreed value to the ownership of the JV. The private sector partner would finance the full required investment for R&M through a mix of equity and loan finance.

    This vehicle was used to form a JV between the State Government of Bihar and NTPC for two generating stations in the state and a similar JV was proposed between NTPC and West Bengal, but this latter JV did not materialise and it was decided that the plants would be scrapped. .

Other aspects of the policy document set out issues related to payment security, contracts & agreements and the procedure for implementation of R&M through competitive bidding. The policy also provides various options for financing and undertaking R&M works with a follow up on prudent O&M practices. The options provide for a risk sharing mechanism in case anticipated benefits do not materialise.

- ***Appellate Tribunal Order***

  In an Order dated 6 June 2007 the Appellate Tribunal for Electricity ruled that the "CEA is no longer the authority to approve projects for additional investments …with respect to generation and it is CERC which is competent to undertake a prudence check and allow capital investment or additional investment for the purpose of determining tariff."

MoP Guidelines

Ministry of Power guidelines for renovation and modernization and for life extension of Thermal Power Plants were issued on 3rd February 2004, in association with the Accelerated Generation and Supply Programme (AG&SP) launched by the Central Government in the 9th National Plan. This was later extended to cover the 10th National Plan, in association with the Partnership in Excellence programme, as outlined above.

The guidelines provide a framework to be followed if generators are to benefit from debt financing from the Power Finance Corporation (PFC) as part of the AG&SP. This provides an interest rate subsidy of up to 3% (or 4% for projects in the North East).

The guidelines outline three main categories of plant that can be considered for R&M and life extension, as follows:

- plant that has been under long term shut down or that has a very low level of performance i.e. Plant Load Factor (PLF) below 40%;
- plant that does not operate to a desired level of performance - i.e. having PLF between 40% to 60%; and
- plant operating at a satisfactory level of performance, but where performance could be further improved/sustained - PLF above 60%.

- ***Units operating at PLF below 40%:***

  For units that are under long term (more than one year) shut down, the decision to revive or scrap the units should be taken by the utilities in consultation with an appointed firm of consultants. A recommendation for scrapping the unit should be forwarded to the existing Standing Committee of CEA for a final decision.

  For other units operating at a PLF of up to 40%, that are not on long term shut down, the performance should be improved by adopting better O&M practices and by using essential resources like spares, trained manpower etc. A suitable consultant with a long and proven track record should be appointed by utilities as early as possible. The initial deliverable for the above exercise is to bring the PLF of the unit to around 50%

Performance of these units should be further improved to a PLF of around 65% by adopting need based R&M works, in a manner consistent with the PIE programme.

Further improvements need to be identified that would secure Life Extension and an optimum PLF, in an economical manner.

- ***Units operating at a PLF between 40% and 60%:***

  A "walk down" exercise should be done by CEA, NTPC (consultant), BHEL and the O&M engineers of utilities, to identify needs based R&M works. Performance of the units is to be improved by taking measures as outlined above. R&M works that will take the plant as close as possible to the design parameters (name plate ratings) should also be identified.

  Further improvements need to be identified that would secure Life Extension and an optimum PLF, in an economical manner.

- ***Units operating at a PLF of 60% or above***

  Efforts need to be made to further improve performance and to sustain high levels of performance. The utilities should adopt the latest O&M practices with the help of a reputed consultant, such as NTPC.

  Life extension studies should be pro-actively undertaken, in a manner designed to reduce the costs of generation, in addition to extending the life of the units. Typically, measures like improvement in heat rate and reduction in auxiliary power consumption need to be considered.

  On-going R&M and LE schemes and Residual Life Assessment (RLA) studies being undertaken with PFC (Power Finance Corporation) funding would continue to be executed as is. These schemes would continue to benefit from grants/interest subsidies loan under the AG&SP, as outlined above.

  These measures are expected to be completed within the timeframe of the 10th National Plan. The working group constituted by the Planning Commission for the purpose of reviewing the AG&SP has recently recommended their continuation to the period of the 11th Plan.

- ***Suggested methodology***

  The guidelines suggest that, for successful implementation, utilities may adopt the following approach:

  - For power stations where BHEL has supplied the main plant e.g. boilers and turbine generator (BTG) sets, the R&M work may be awarded through negotiations with BHEL. BHEL should ensure reasonable prices. Further, attempts should be made to restrict the cost of Life Extension (LE) works to between 0.8 and 1.25 Crores/MW, depending on the quantum of LE works. The utility shall accept the price negotiated by the committee of CEA, (now CERC), NTPC and the utility (see below);
  - For power stations where BTG equipment of a different make is installed, the utility may appoint a consultant, such as NTPC, NLC, APGENCO, KPCL;

- The utility shall prepare the R&M proposal, including benefits, in association with the consultant and submit this to the CEA (now to CERC) for clearance and to the PFC for sanction of a loan under the AG&SP. While preparing the tender specifications for R&M/LE works, the utility may stipulate only performance related guarantees, such as plant capacity, heat-rate, boiler-efficiency and stabilised operation for 1-2 years. The utility should not stipulate guarantees for parameters such as PLF, generation dependent availability, etc.
- RLA & Life Extension works should be carried out simultaneously in one shut down, by the appointed agencies. For the Balance of Plant (BOP) equipment, where no RLA is required, R&M work may be taken up simultaneously. However the consultant must ensure that all BOP is covered under an R&M programme.

A Committee, consisting of CEA/CERC, NTPC and concerned utilities, will negotiate with BHEL for R&M and LE works for units supplied by BHEL. Responsibilities with regard to implementation of R&M and LE works will be shared as indicated below:

- **MOP**: As Monitor
- **CEA**: Govt. inputs, policy decisions, follow up/monitor with utilities/SEBs
- **NTPC**: For technical inputs and supervisions
- **PFC**: To provide funds as loans
- **BHEL**: To carry out the field work

For units not manufactured by BHEL, BHEL may be contacted for supplies, through reverse engineering and further execution of works.

The fee to be charged by the consultant should be on an actuals basis and should be cleared by CEA (now CERC). The consultant's fee should be included in the project/scheme cost. In order to sustain best practice, consultancy advice should include the introduction of best O&M practices, supervision of RLA studies, execution of LE works and supervision of O&M practices for one-two years after the completion of LE works.

- ***Timetable for project completion***

As the entire LE & R&M works for the identified units have to be completed during 10th Plan period, the following time frame must be adhered to for implementing the scheme:

- appointment of consultant by the Utilities-1 month;
- freezing the Scope for work/activities for RLA//R&M - 2 months;
- placement of order after negotiations with the implementing agencies --3 months;
- completion period: 30 months as per details given below:
- to improve the PLF to >40% for Category-I Units - 8 to 12 months;
- to improve the PLF to >60% for Category-II Units. - 12-18 months; and

- execution of LE Works - 18-30 months.

We note that in practice a large number of projects identified for inclusion in the 10th Plan have been carried over for completion during the period of the 11th Plan.

- ***Other key issues***
  - Utilities should take prompt action for executing loan documents with PFC and draw the loan for availing interest subsidy under AG&SP and timely completion of project
  - A nodal officer at the level of Chief Engineer should be identified by the utility for coordinating these works
  - CEA will monitor the implementation of R&M and LE programmes, as per the above schedule and carry out the post implementation evaluation of benefits from the scheme
  - During the implementation of R&M/LE works, adequate power to cover the shortfall in generation because of shut downs for the units (under RLA/R&M/LE) will be made available from the unallocated quota in the Central Pool
  - This policy framework provides for a major risk reduction to the owner in terms of financing, cost over runs, prudent O&M practices and performance guarantees. The suggested risk mitigation measures should therefore provide a boost to R&M activities.

Expert Committee on Integrated Energy Policy

In summary, the key recommendations outlined in the August 2006 report of the expert committee on integrated energy policy, in so far as they are relevant to this Annex, were as follows:

- ***Introduction***
  - India must pursue technologies that maximise energy efficiency, demand side management and conservation.
  - Rehabilitation of existing thermal stations could raise capacity at least cost in the short-term and must be taken up urgently.
  - The Government should aim to increase the gross efficiency in power generation from the current average of 30.5% to 34%. All new plant should adopt technologies that improve their gross efficiency from the prevailing 36% to at least 38-40%.

- ***Supply Options***

  India's conventional energy reserves are limited and all available and economic alternatives must be developed. Simultaneously, a major stress must be laid on energy efficiency and conservation, with particular emphasis on the efficiency of electricity generation, transmission, distribution and end-use. Over the next 25 years energy efficiency and conservation are the most important virtual energy supply sources that India possesses.

The efficiency of coal power plants can be improved substantially. The average gross efficiency of generation from coal power plants is 30.5%. The best plants in the world operate with super critical boilers and have a gross efficiency of 42%. Latest reports indicate that Germany is claiming gross conversion efficiencies of 46%. It should therefore be possible to achieve a gross efficiency of 38-40% at an economically attractive cost, for all new coal-based plants. This will reduce pressure on India's coal supplies.

- ***Policy for Energy Efficiency and Demand Side Management***
  - Barriers to the adoption of efficient technologies have to be removed and encouragement to develop and deploy more efficient technologies has to be provided. Public policy can set the pace for such development by offering attractive rewards and imposing biting penalties.
  - Energy efficiency and conservation programmes and standards should be established and enforced.
  - India should adopt a least-cost planning and policy approach that ensures that energy efficiency and DSM have a level playing field with supply options…… This would become part of the least-cost plan before putting in new power plants that may cost Rs. 40,000-50,000/peak kW generated.
  - Measures to increase the efficiency of coal-fired power plant require NTPC and State owned generating companies to acquire technology that will enhance the fuel conversion efficiency of the existing population of thermal power stations from an average of 30% to 35%. No new thermal power plant should be allowed without a certified fuel conversion efficiency of at least 38-40%. While competitive tariff based bidding can balance fuel efficiency against capital cost and provide incentives for efficiency improvement, in the absence of such competition the pace of efficiency improvement needs to be forced.
  - Incentives for increasing the energy efficiency of thermal power stations needs to be provided through appropriate pricing and policy interventions.

ADB and GEF funding programmes

As noted above, despite the availability of subsidised funds from the PFC there has been a limited take up of funds available to support R&M programmes.

There was a similar experience in relation to US$150m of funding available through the Asian Development Bank (ADB). This was made available for R&M of generation projects, but attracted little interest, reportedly because there appeared to be limited incentives for state generators to commit to higher environmental standards.

In turn this led to the present Global Environment Fund (GEF) scheme, whereby the incremental costs of energy efficient R&M may be supported if an energy audit is undertaken to assess the baseline and demonstrate the success of the funding programme. Even so and despite evidence that positive financial returns can be generated, interest is reported to be low.

Conclusions

It can be seen from the above summary of the policy, legislative and planning framework that there is a high level of policy commitment to R&M projects in India and that this is supported with a considerable central planning and Indian and international funding programme.

Whilst the framework can be argued as supportive of R&M, it essentially leaves states with responsibility for prescriptive actions that would force it to happen. Unfortunately, at present there is a level of mistrust between regulators and state owned Gencos and both appear to be essentially reactive.

The R&M programme itself appears to be enjoying somewhat mixed success, with reasonable progress achieved against what might be seen as a relatively ambitious framework contained in the 10^{th} National Plan. It also appears to be the case that the policy framework is essentially focussed on plant load factor enhancements (which will in themselves result in heat rate improvements) but are not specifically focussed on energy efficient R&M and on optimising heat rate improvements.

Applicable Regulatory Rules

This Section reviews the specific regulatory rules, procedures and incentives applicable to R&M/LE projects in India at the present time. It focuses on the rules applied by the Central Electricity Regulatory Commission to centrally owned generating capacity. These also act as guidance to state regulatory commissions, in accordance with section 61 of the Electricity Act.

It also specifically reviews the rules applicable in three separate states: Uttar Pradesh, West Bengal and Maharashtra, though similar rules apply in most other states. The actual operating parameters compared with the norms prescribed for the generating companies of these three states are set out later in this Annex.

Introduction

As described previously in this Annexc, tariffs for generating stations owned by central government, or generating stations supplying power to more than one state are governed by CERC tariff regulations (as described above). State Regulatory Commissions are empowered to determine tariffs of generating stations located in that state and supplying power to a distribution licensee in that state.

The existing tariff regulations at both central and state level are based essentially on “cost plus” principles. However, a number of states have issued, or are on the verge of issuing, multi year tariff orders designed to create a framework with greater investment and regulatory certainty and to facilitate efficient expenditure through benefit sharing, during the applicable control period.

In India the multi-year tariff order works on the basis that the approved project cost and its financing plan form the basis for tariff determination. The allowed tariff is divided into two parts, fixed and variable. The fixed part comprises principally operation and maintenance (O&M) expenditure, depreciation, loan interest, taxation and a return on equity employed. The variable part (referred to as the energy charge) comprises the allowed fuel cost.

Costs are then categorised into controllable and uncontrollable costs, with generators responsible for controllable costs, which are recoverable on the basis of normative parameters fixed by the appropriate regulatory commission for the control period.

To the extent that efficiency levels are higher than assumed in the norms the generators receive the benefit of the assumed (but not incurred) cost recovery level for the length of the control period. To the extent that efficiency levels are lower than the assumed norms generators are generally unable to recover revenue to cover the additional costs and the generator will need to make savings in the other elements of the cost base, or incur a loss. There have been some instances where variations in controllable costs have been considered in the tariff, through a tariff review.

Variations in uncontrollable costs, such as the gross calorific value (GCV) and price of fuel are permitted to be passed on to customers in the generator’s tariffs, though the generator’s use of fuel will be calculated on the basis of fixed operational benchmarks and not on the basis of actual use.

Benchmarks were initially set in 1992 and it was expected that they would be progressively updated to reflect actual performance, this does not appear to have happened, as a result of what have been termed information asymmetry problems.

In addition to energy cost benchmarks, generators may also receive a plant load factor (PLF) incentive, whereby the generator receives a flat rate payment for every unit generated in excess of the normative PLF.

- ***Central Electricity Regulatory Commission (CERC)***

  The Terms and Conditions of Tariff published by the Central Electricity Regulatory Commission (on 26th March 2004) apply to only NTPC, although State Electricity Regulatory Commissions are required to be guided by the principles and methodologies specified by CERC. Together with notified amendments they provide that capital expenditure incurred in relation to existing plant can be considered for inclusion in tariffs, subject to a prudence check, as follows:

- ***Regulation 18***

  Additional Capitalisation can be considered in the following circumstances:

  - 18(2): Any additional works/services which have become necessary for efficient and successful operation of the generating station but that are not included in the project cost; and
  - 18 (4): Impact of additional capitalisation in tariff revision may be considered by the Commission twice in a tariff period, including revision of tariff after the cut off date.

  This is subject to the following conditions:

  - Note 2: Expenditure on replacement of old assets shall be considered after writing off the gross value of the original assets from the original cost;
  - Note 3: Expenditure admitted by the Commission for determination of tariff on account of new works, not in the original scope of work, shall be serviced on the basis of the normative debt equity ratio specified in regulation 20; and
  - Note 4: Expenditure admitted by the Commission for determination of tariff on renovation and modernization and on life extension shall be serviced on the basis of the normative debt equity ratio specified in regulation 20, after writing off the original amount of the replaced assets from the original project cost.

  By an amendment of 11th August 2005, CERC modified Clause 17 of the regulation to provide for in principle clearance of the capital cost and financing plan for capital works, which are to be considered on the basis of merit, after a detailed cost benefit analysis.

- ***Regulation 20***

  Regulation 20, on the Debt-Equity Ratio (as amended on 1st June 2006) provides that in the case of the existing generating stations, where additional capitalisation has been completed on or after 1.4.2004 (and allowed by the Commission under Regulation 18) equity in the additional capitalization shall be the lowest of:

- 30% of the additional capital expenditure admitted by the Commission; or
- the level approved by the competent authority in the financial package for additional capitalization; or
- the actual equity employed.

The regulation also notes that the CERC may consider equity of more than 30% if the generating company is able to satisfy the Commission that deployment of such equity was in the interest of the general public.

Similar provisions exist for cases where investment approval was given prior to 1.4.2004 but where the date of commercial operation is likely to be during 1.4.2004 to 31.3.2009.

The debt and equity amount arrived at in accordance with clause 1) shall be used for calculating the allowed interest on loans, the allowed return on equity, any advance against depreciation and any foreign exchange rate variation.

CERC approved what might be described as "liberal" norms in respect of R&M works at two relatively small units at the Tanda and Thalcher power stations. However, beyond the broad provisions outlined above, the process for approving specific proposed R&M costs, assessing the potential benefits of an R&M project, setting subsequent operating norms and a trajectory for their achievement, has not yet been transparently documented.

Thus, there is at present little effective guidance from the CERC to state regulators in relation to the assessment and approval of specific R&M projects. This may act to reinforce the generators' uncertainty and general reactivity in relation to R&M projects.

- ***Benchmarks***

In the tariff order, CERC tightened the heat rate benchmarks for the period from 2004 to 2009 to 500MW units from 2500/kcal/kWh to 2450kcal/kWh. It left the benchmark for the smaller (and mostly older) 200/210 and 250MW units at 2500kcal/kWh but also set the same heat rate benchmark for old and new power stations.

The PLF incentive set in the tariff regulations is 80% and the incentive for each additional unit is Rs 0.25kWh.

Because the PLF incentive gives a signal for excess generation, whether or not it is needed, some problems occurred with continued generation, causing system frequency problems. As a result, in 2002 CERC introduced an Availability Based Tariff (ABT) which levied an unscheduled interchange (UI) charge for generation at times of high system frequency. In effect, at times of high system frequency the generator receives no payment for power spilled on to the system in excess of scheduled output.

At times of low frequency the generator is required to pay a penalty in the event that generation output is less than scheduled.

Uttar Pradesh

- ***Terms and conditions of generation tariff***

  Regulations 18 and 24 of the Uttar Pradesh Electricity Regulatory Commission (UPERC) terms and conditions of tariff, dated 7th June 2005, provide as follows:

  - **Regulation 2(4)**

    The Commission shall encourage generating companies to adopt the Clean Development Mechanism and Carbon Trading. A major part of the benefit accrued as a consequence of CDM and Carbon Trading shall be retained by the generating company. Transactional costs involved in such activities shall form a pass through element in the tariff, subject to due diligence in case no carbon credit is available.

  - **Regulation 18**

    Regulation 18 is essentially the same as the CERC's Regulation 18, as summarised above.

    In view of past performance, UPERC has fixed operating norms below the benchmark levels prescribed by CERC for some stations. These gradually become stricter.

- ***(Draft) First amendment to the terms and conditions of tariff***

  The (draft) first amendment to the Uttar Pradesh terms and conditions of tariff, published in November 2007, provide as follows:

  - **Regulation 16 - Norms of Operation**

    "In the case of non-availability of unit(s) due to Renovation & Modernization, the effective capacity left after discounting the capacity of such of unit(s) shall be considered for the purpose of calculation of plant availability and annual capacity (fixed) charges and for the purpose of plant load factor calculations;"

    After the Renovation & Modernisation of generating unit(s) in a generating station:

    - the gross station heat rate shall be deemed to be higher by 50 kcal / kWh;
    - secondary fuel oil consumption shall be deemed to be higher by 0.2 ml / kWh;
    - auxiliary energy consumption shall be deemed to be higher by 0.5%;
    - for an initial period of 180 days following re-commissioning;.

    The draft regulations propose to clarify the methodology for computation of annual fixed charges for units which have been taken out of service for R&M. Furthermore, an allowance in the operating parameters is proposed for units which have undergone R&M for the stabilization period of 180 days.

- ***Terms and Conditions of Distribution Tariff Regulation 2006***

  The Uttar Pradesh terms and conditions of distribution tariff regulations, dated 6th October 2006 provide as follows:

  - **Regulation 4.2 (1)**

    The Distribution Licensee shall have the flexibility of procuring power from any source in the country. However, the Distribution Licensee shall procure power on a least cost basis and in accordance with the merit order principle. A two-part tariff structure shall be adopted for all long term contracts in order to facilitate merit order dispatch.

  - **Regulation 4.2 (8)**

    For the tariff year, the total power purchase cost for the distribution licensee's requirement for sale to its consumers shall be estimated on the basis of merit order principle.

- ***Guidelines for forecasting, resource planning and power procurement***

  - The Licensee is required to procure power through an economical, efficient and transparent process.
  - The Licensee is required to prepare a purchasing plan in consultation with the transmission licensee, generating company, state government, Commission, Regional Electricity Board, CEA and other relevant agencies.
  - The licensee is required to demonstrate that while preparing this plan it has examined the economic, technical system and environmental aspects of all reasonable options available to satisfy the energy needs of its consumers.
  - The plan should be at least financial cost to the licensee.
  - The principles of least cost and merit order and the requirement to procure power in an economical and transparent process require the licensee to justify that it has considered all possible options for an increase in supply availability and the proposed plan provides power at least cost.
  - The distribution licensee and the generator would be required to evaluate the option of either generating more from an existing inefficient plant (after R&M) or setting up a new plant.

- ***Order regarding refurbishment of 5 x 200 MW units at Obra B TPS***

  In an Order dated 7th November 2006, the UPERC granted clearance, in principle, to the scope of work, costs and operating parameters expected of the plant after refurbishment. This has reduced the perceived risk of ex-post cost disallowance. However the Order contains no mention of the economic principles on which the R&M proposal was evaluated.

- ***Multi-year Tariff Order***

  In its Multi-year Tariff Order dated 26th March 2007, applicable to UP Rajaya Vidyut Utpadan Nigam Ltd (UPRVUN Ltd), for the period 2005-06 to 2007-08 the UPERC determined fixed charges taking account of additional capitalization proposed by the UPRVUN.

  The UPERC expressed its dissatisfaction with delays in carrying out R&M works and directed the company to submit the following:

  - details of units commissioned during 2005-06 and 2006-07, following R&M works;.
  - the re-commissioning schedule during 2007-08; and
  - the planned schedule of R&M for the year 2008-09 and beyond.

  For 2005-6 and 2006-7 the Commission relaxed the PLF norms and considered actual performance. For 2007-8 the PLF target for all power stations except Obra "A" was retained as per the applicable Regulations. The target PLF for Obra A was revised, since only units no. 1, 2, 7 and 8 would be available for generation and the remaining units would be shut down for R&M purposes. The Commission approved the following PLF for 2005-6, 2006-7 and 2007-8:

Annex 4, Table 4 – PLF norms approved by the UPERC

Year	Anpara A	Anpara B	Harduagunj	Obra A	Obra B	Panki	Parichha	Parichha Extn.
FY 06	75	85	20	18	55	50	45	-
FY 07	75	80	28	24	55	50	50	80
FY 08	80	80	40	40	75	65	60	80

However, the Order stated that no "incentive" should accrue to the company for the years 2005-06 & 2006-07 if actual PLFs were less than those specified by the Commission in the Generation Tariff Regulations for those years. In effect, the company was able to recover O&M costs and debt financing costs if achievement was below the normative or target PLF, but was not permitted to earn a return on equity employed.

- ***Review Order of Multi Year Tariff Order***

  In a Review Order of the above Multi-Year Tariff Order dated 10th October 2007 the UPERC:

  - did not agree that the PLF target for 2007-8 should be revised downwards
  - ruled that indifference towards commercial and efficient operations and unreasonable delays caused in commencement of R&M for units at Obra A & Harduaganj were responsible for continuing poor performance;
  - directed UPRVUN Ltd to:

- ensure that units 1,2 & 6 at Obra A, units 9,10,11,12 & 13 at Obra B and unit-5 at Harduaganj were re-commissioned on the basis of the R&M proposal;)

- remove the uncertainty surrounding the completion of R&M at units 3,4 & at Obra A;
- take prompt decisions where R&M has become necessary at other generating stations; and.
    - decided that only the effective capacity left after discounting capacity under R&M could be considered for the purpose of PLF and plant availability during 2007-08 and 2008-09.)

In order to do achieve this UPERC extended the validity of its MYTO by a year, to include 2008-9 (for those units subject to R&M only). This is an interesting precedent that could give greater regulatory certainty for other R&M projects.

West Bengal

- ***Terms and Conditions of Tariff Regulation***

In addition to general provisions relating to such matters as competition, efficiency, the economical use of resources, good performance and environmental standards, the West Bengal Terms and Conditions of Tariffs Regulations 2007, issued by the West Bengal Electricity Regulatory Commission (WBERC) and dated 9th February 2007, provide as follows:

- approval of the WBERC is required before any capital expenditure is incurred by a generating company;
- the annual rate of return included in tariffs is to be based on a trajectory to normative parameters prescribed by the WBERC;
- generating companies should file a detailed capital investment scheme, together with a capitalisation schedule covering each year of the control period and a perspective plan for the period 2008 to 2011;
- the power procurement plan of the Distribution licensee should include measures proposed to be implemented as regards energy conservation and energy efficiency and be based on a least cost approach;
- expenditure on renovation and modernization and life extension shall be financed on a normative debt equity ratio, after writing off the original amount of the replaced assets.

In relation to incentivisation and benefit sharing, the regulations make separate provision for revenue and capital accounts:

- for capital items, one-time proceeds accruing to the company from carbon trading, or a similar environmental pollution reduction programme, that are to be invested in the creation of a new asset in the electricity business of the company, will earn the appropriate return on equity. For tariff determination purposes, the investment amount will be deducted from the project cost during the computation of depreciation;
- for revenue items, net income earned by the company from carbon trading or a similar programme, shall be used partially for the benefit of consumers, by utilizing 30% of such income to reduce the aggregate revenue requirement. In the case of a loss from such a

programme, such loss shall not be added to the aggregated revenue requirement.

Thus, through application of the principles of least cost purchasing and merit order, the WBERC can effectively require the distribution licensee and generator to choose between increased generation from existing plant after R&M and supplies from new build capacity.

- ***Draft Terms and Conditions of Tariff Regulation 2007***

  The draft West Bengal Terms and Conditions of Tariff Regulation, dated 15th October 2007, proposes specific norms for operating parameters over the 8 year control from 2009 to 2016. This provides a considerable period of stability for generators to plan and execute R&M programmes.

  On 15th November 2007 the West Bengal Power Development Corporation requested that the WBERC set liberal operating norms and stated that it believes the proposed norms are not achievable, for technical reasons.

Maharashtra

- ***Terms and Conditions of Generation Tariff Regulations***

  The Terms and Conditions of the generation tariff issued by the Maharashtra Electricity Regulatory Commission (MERC) provide as follows:

  - variations in capital expenditure on account of time and cost overruns are to be considered as controllable;
  - in the case an existing power station, the MERC shall determine the tariff with regard to the historical performance of the station and reasonable opportunities for improvement in its performance, if any;
  - additional capitalization may be allowed, in line with CERC rules;
  - renovation, modernization and replacement are assumed to be funded at a normative debt: equity ratio of 70:30.
  - the power procurement plan of the distribution company should be in accordance with the merit order

- ***Multi-Year Tariff Order for MSPGCL***

  In its multi-year tariff order to MSPGCL (Mahagenco) the MERC asks Mahagenco to maintain a clear demarcation between capital and revenue expenditures and to submit capital expenditure proposals for R&M schemes for approval.

  MERC recognised the urgent need for R&M on some generating units. Therefore it allowed expenditure proposed by Mahagenco on an “in principle” basis, subject to a warning that this does not absolve Mahagenco of responsibility to undertake cost-benefit and financial analysis to check the prudence of its expenditure.

  MERC also warned that schemes should be prioritized and that projected benefits should accrue to stakeholders. Mahagenco was asked to report the progress of each scheme and to report its expenditure and the benefits accruing.

Following an appeal to the Appellate Tribunal, the Tribunal stated in an order of 10 April 2008 "under the circumstance we feel that the Commission, either on its own or through the Appellant, engage appropriate independent agency(ies) who can carry out a study….(preferably within 3 months) …to reasonably assess the achievable station heat rate of the plants owned by the Appellant ….and to …suggest measures to improve the station heat rates over a period of time."

Furthermore the Tribunal stated that "the Commission is directed to determine the station heat rates in respect of plants owned by the Appellant. Till such time, the Appellant may continue with the pre-existing tariff, subject to trueing up with the revised station heat rates, when available."

- ***Multi-Year Tariff Order for Tata Power Generation (TPC-G)***

  The MERC's multi-year tariff order for TPC-G dated 2 April 2007 additionally provides:

  - **Operating norms**

    The operational parameters for some generating stations are better than norms, but for some units actual performance is lower than norms. In accordance with the provision in the Regulations, there is a need to specify operational norms for existing generating stations based on historical performance of the generating station.

    If historical performance is considered *in toto* for units whose operational performance is better than norms, there will be no room to motivate the utility to improve further. Similarly, for units whose historical performance is lower than norms, there is a need to gradually improve performance in order to achieve stipulated norms.

    There shall be an incentive of Rs 0.25 paise/kWh for scheduled energy generated and delivered to the transmission system in excess of a normative Plant Load Factor of 80 percent.

- ***Multi-Year Tariff Order for Reliance Generation (REL G)***

  MERC's multi-year tariff order for REL-G dated 18th April 2007 states that MERC has not considered the estimated incentive as part of the aggregated revenue requirement. This is because the incentive is not a cost component but a tariff component. Rather, the generation incentive will be payable at the rate of Rs 0.25/kWh for actual scheduled generation delivered to the transmission system in excess of a normative Plant Load Factor of 80%.

Conclusions

The regulatory frameworks at central and State level do recognize the importance of R&M as a cost effective measure for meeting India's energy requirements. However, there appears to be a gap between the policy intent and the translation of that intent to practical reality. Generators do not perceive the present framework to provide them with the incentives, or to reflect the risks they incur in implementing energy efficient R&M projects. They may also be argued to be reactive rather than pro-active in their response to R&M opportunities

Our detailed comments in respect of potential barriers to R&M within the regulatory framework and some initial suggestions for improvement to the regulatory framework are set out later in this Annex.

Stakeholder perspectives

As discussed above, during the Inception mission for the project we held an extensive series of stakeholder liaison meetings, including discussion with:

- the Central Electricity Regulatory Commission (CERC)
- three separate state regulatory commissions - Maharashtra, Delhi and West Bengal;
- the Central Electricity Authority (CEA);
- four generating companies, representing both state and centrally owned companies - National Thermal Power Corporation (NTPC), Maharashtra State Power Generation Company Limited (Mahagenco), West Bengal Power Development Corporation (WBPDCL) and the Damodar Valley Corporation; and
- discussion with Steag, the World Bank/GEF technical consultants.

In addition, there was continuous liaison with the Forum of Regulators (FoR).

As a result of the extensive and resource intensive nature of these meetings and the excellent liaison with the FoR it was not considered necessary to undertake an additional telephone survey.

A brief outline of the key points raised by stakeholders during each of the stakeholder liaison meetings is set out below. These are presented in temporal order in order to better reflect the development of the project team's thinking. It should be stressed that this represents the views put to us by stakeholders and does not necessarily reflect our views of the issues.

Maharashtra Electricity Regulatory Commission (MERC)

- The existing tariff regulations applicable to Mahagenco (the Maharashtra State owned generating company) provide a "Cost Plus" framework on a 5 year basis and include:
  - A baseline
  - Target performance norms and a trajectory for improvement; and
  - Efficiency gains (for improvements in heat rate, etc)
- Case law in Maharashtra is developing. Efficiency norms set by MERC have been challenged by Mahagenco at the Appellate Tribunal and the results of the Tribunal's inquiry should be known very soon (this was correct at the time of the meeting).
- Energy efficient rehabilitation and maintenance (EE R&M) is not specifically addressed in the current regulations. Cost pass through for R&M investments is permissible, subject to assurance that improvements in efficiency parameters are actually delivered.
- There have been no applications for expenditure on EE R&M so far
- It would be difficult to provide an additional incentive (e.g. higher return) for EE R&M, because consumer groups would be likely to object. This might be reduced if clear efficiency benefits could be shown, as this would reduce the need for expensive imported power.

- It might be difficult to undertake EE R&M during an election period, because there would be an enhanced sensitivity to costs of additional imported power and potential increases in outages, against a background of the large power deficit that exists in the state.
- Mahagenco might not respond rationally to an enhanced economic signal for EE R&M. There appeared to be a form of political preference for new build
- Gencos prefer new build over R&M because of the increased potential to add a large increment of capacity; and the greater visibility associated with new capacity additions;
- The investment approval process does not test if EE R&M has been considered
- MERC has allowed Energy Efficient-Demand Side Management (EE-DSM) costs to MSEDCL as pass through, but the response has been low;
- In the present system, the Heat Rate (HR) trajectory is given and the incentive is to beat the trajectory, but Mahagenco disagrees on the proposed trajectory;
- An alternate arrangement might be to allow the new-build tariff (or slightly less than that) for R&M projects
- PSP/PPP options could be considered for increasing the uptake of R&M, since private operators will be better able to respond to the economic incentives in the regulatory regime. It was considered that this could potentially be achieved through a form of Rehabilitate-Operate-Transfer (ROT) scheme or through some form of Joint Venture.

Maharashtra State Power Generation Company Limited (Mahagenco)

- Mahagenco is the Maharashtra state owned generating company, the successor generator to the old integrated state electricity board.
- New build plant is a better solution than R&M of existing plant. Mahagenco referred to studies and reports that have concluded that further focus on major R&M and Life Extension (LE) is not warranted and that the very large power shortages in Mahrashtra require substantial new build capacity
- For a proposed R&M project at the Koradi power station bids were called. Whilst the internal cost estimate was Rs 1-1.5cr/MW (approx US$250,000 to US$375,000/MW) the received bids worked out to upwards of Rs 2cr/MW (approx US$500,000 per MW).
- Two 38 year old 62.5MW units (Paras and Bhusawal) were internally agreed as candidates for R&M approximately two 2 years ago. However, there was no bidder for Paras whilst for Bhusawal the bid was higher than an internal estimate at Rs 150cr (approx US$37.5m) cost estimate. BHEL had indicated that they would bid for the work but decided not to. Therefore Mahagenco decided to replace the units with a new 250MW unit, instead of spending on renovation.
- Small R&M schemes have been taken up but minimal capital expenditure is now being done on the plant and the plan is to continue to run them for another 3-4 years, until they can be replaced.

- There remain risks relating to the achievement of performance improvement, even after spending cash on R&M. Contractors are not willing to guarantee resource improvements beyond the first year of operation
- MERC has prescribed HR improvements but Mahagenco feels that there is uncertainty in relation to the pass-through of actual costs, if performance falls short of the MERC's prescribed norms. They felt that the new tariff regulations are unproven and that the regulator needs to be more constructive in terms of norms. They hope that the Appellate Tribunal will prescribe a more practical approach
- MERC is insisting on testing compliance for HR norms against a trajectory set in 2003. Mahagenco wants a comparison against 2005 levels, because they became a separate company in 2005
- Once performance norms have been achieved the regulator will simply tighten them again, leading to larger losses in the future
- Investment decision making processes exist. An internal checklist is used for cost-benefit analysis. An annual budgeting process is followed for each plant and monthly reviews are also done.
- Various factors that impact performance are beyond the control of Mahagenco, especially coal quality and railway deliveries. Both of these providers are unregulated monopolies.
- Cost increases and quality problems arising from coal quality and railway problems should be regarded as uncontrollable costs and subject pass through. At present Mahagenco takes the financial hit in relation to coal transit losses because they are only allowed to recover fuel costs at normative levels.
- Normative targets should be unit specific and recognize that there is a level beyond which efficiency cannot be further increased, especially with older plant. Norms should take account of real world delivery and quality problems.
- Mahagenco believes that CERC sets different norms for different plants, taking vintage into account, but suggested that MERC has not yet recognized this issue
- A normal 4 yearly overhaul requires an outage period of around 20-25 days
- An increase in the return for R&M projects would be interesting, but the key issue is the level of risk, for example, if the anticipated heat rate improvements were not met.
- The additional risks compared with new build fell into the following key areas: regulatory uncertainty; contractor guarantees and performance improvement
- Mahagenco has proposed an O&M contracting approach to MERC. It is amenable to HR and cost being determined through competitive bidding, provided it is sure that the bidding outcome would be accepted by MERC.
- It would be advantageous if plant subject to R&M was then effectively outside of the cost plus regulatory process.
- The present dialogue with MERC is not good, especially in the light of the Appellate Tribunal inquiry (as summarised above). Mahagenco has tried and failed to establish a constructive dialogue with the MERC.

- Import tax is paid on capital equipment necessary for R&M but not for a new build mega-project greater than 1,000MW.

Steag

- They have identified approximately 85 units that are more than 20 years old at or around 200MW that are the primary candidates for EE R&M
- Units were designed for 5,9000 kcal coal. but 3,600 kcal or even lower is typically available in India now.
- Efficiency of units starts at around 2,400 to 2,500 but deteriorates to around 3,200 over the plant life
- If 2.5% is spent on O&M and the unit is subject to four yearly overhaul it should be possible to achieve a heat rate of at least 2,700 to 2,800. Expenditure of Rs 130cr to Rs 140cr (US$32.5m to US$35m) should get the plant back to its design efficiency.
- After completion of a major R&M project, efficiency levels should be higher, perhaps around 2370kcal and it should take around 3 months to complete the process. It was felt that Gencos were rewarded adequately for achieving auxiliary power consumption of 9.55% to 10% and that there was no incentive to reduce this to say 7%.

NTPC

- NTPC policy is to consider plant for R&M after 100,000 hours running time. NTPC feels that it is more active in this respect than State owned Gencos
- They first consider total replacement of control and instrumentation equipment, the costs of which are recoverable if the existing controls are obsolete and the manufacturer is unable to support piecemeal replacement
- NTPC will consider uprating plant to enhance efficiency levels, but only on the basis that there is benefit sharing. This is under discussion with the CERC. Otherwise, major long term R&M must be justified on the basis of plant life extension
- Problems arise in relation to buyer requirements and the costs of alternative power, if a plant proposed for R&M is to be unavailable for a long period. The buyers' consent must be obtained and this is especially difficult if a plant has a series of buyers
- A new CERC tariff policy was introduced in September 2006. This gives an availability (PLF) incentive at levels over 80%
- It was expected that a new CERC regulation will tie the company to availability targets set out in a management plan and reflect the specific situation of the company, rather than a broad normative target
- There is no clear reward for operating plant a long way in excess of the regulator's performance targets
- In relation to poor performing plant recently acquired by NTPC (for example, in settlement of State power purchasing debts) it was proposed that norms should be based on existing actual levels of performance. CERC disagreed and required NTPC to stabilise the operation of the plant before norms were set.

- NTPC felt that the option of bundled R&M and O&M contracts from contractors, with the plant moving to something like a new build regulatory regime would be an attractive option.

Delhi Electricity Regulatory Commission (DERC)

- Planning guidelines in Delhi should capture the need for R&M investment and the DERC will then develop a sharing mechanism. Gencos can propose a business plan for review at Public Hearing for a 5 year multi-year tariff order (MYTO). This acts as a kind of "pull" for R&M assessment, which may not happen elsewhere
- Even if projected heat rate savings do not materialize the Genco will still make additional revenue from those savings that are achieved
- Degradation is not really dealt with in the regulatory framework. Norms are intended as a kind of portfolio target. For a single plant Genco it would be possible to set tougher norms and to allow for degradation in performance.
- Regulators could consider a longer price control period than 5 years and build in some correction for the risks of implementation of planned R&M
- It is important to note that Gencos are not licensed and that the role of Regulatory Commissions is limited
- The Delhi Tariff Order will be published on the Commission's website shortly

CEA

- Regulators may seek the advice of CEA, including in relation to setting of norms, but this is not binding
- CEA believes that some NTPC plant is operating efficiently but that for many other plant there is imprecise measurement
- There are around 200 units that are 20-25 years old and that will need to be brought to their design heat rate
- Gencos prefer new build and may have staffing and skills shortages
- There is a problem in relation to a shortage of contractors able to undertake R&M work
- NTPC continues to send its proposals for R&M to the CEA for evaluation and comment. NTPC believes this process gives added comfort to CERC.
- The analysis CEA carries out is mainly engineering/technical and not cost benefit type
- There is an exemption on import tax for plant of 1000MW and above
- There is a tolerance level in Station Heat Rate (SHR) of approximately 2%-3%
- Degradation should not be beyond say 6% to 7%. There is around 2% degradation in plant efficiency over 5 years, but approximately 1.8% of this can be recovered at periodic overhaul. However, the approximate 0.2% loss gives a total loss of around 1%-2% over the lifetime of a plant
- There is scope for reduction in auxiliary consumption around the country

CERC

- Additional purchasing costs (faced by Discoms) resulting from outages required for R&M could be capitalized. States should look at the impact on power purchasing costs of the Discoms over a period of time, depending on what is necessary
- CERC is going to produce guidelines on life extension, though this will not really cover SHR
- It is necessary to set realistic norms for older plant
- States need to be able to appoint contractors to undertake R&M work
- It is not easy to identify costs related to capacity upgrade, plant life extension, station heat rate improvements and availability as discrete components. The same engineering solutions could impact several of these at the same time
- However, it is necessary to distinguish between R&M costs and those life of plant costs already remunerated under the tariff regime
- Gencos could consider selling output on the open market if their state Discoms will not buy the additional output

West Bengal Power Development Company Limited (WBPDCL)

- WBPDCL stated that it has no difficulty in recovering fixed costs, which are in any case very low because of the ageing plant portfolio and low residual depreciation charges. However, it is lagging far behind the set norms on variable costs because of the tough normative targets set by the regulator.
- Coal quality is a particular problem. There are frequent disputes. Performance against norms is measured on the basis of the declared quality delivered. WBPDCL believe they are getting lower quality coal than that declared. Joint coal testing has now started but there are still problems.
- They are carrying out energy audits but there is still some discrepancy between unit rates they are measuring and station norms set by WBERC
- New norms are station rather than unit specific and derived from TERI (The Energy Research Institute).
- For example for Bandel the actual measured SHR is 3250 and the regulatory norm is 2900. The discrepancy results mainly from coal storage and handling losses, grade slippage and the quantity of stones and other material delivered in the coal shipments.
- WBPDCL believe that unit heat rates would insulate them from the "lost coal" problem
- The norm for coal transit loss is 1.5% but the actual figure is nearer to 2% and WBPDCL has no control over transit losses
- Norms will be set for a longer period (8 years) in the new framework introduced by the MYTO.
- WBPDCL are considering R&M on 210MW units, but planning to scrap 65MW and 110MW units

- They were very interested in the concept of treating R&M as if it were a new build IPP with say a 10 year PPA
- They are importing approximately 30,000 tonnes of coal per month from Indonesia, at a calorific value of 4,800 per tonne, compared with a claimed 2,500 per tonne for domestic coal

WBERC

- No special incentive is required for EE R&M. Heat rate is only a part of the picture
- WBERC is sceptical that R&M could be more cost effective than new build
- Performance guarantees are the key question because there have in the past been investments of this type that haven't delivered benefits for customers.
- If a proposed R&M investment was subject to scrutiny through a formal case and a hearing and the case is proven, the regulator should allow it to be passed through, albeit with some risk that the anticipated extra units might not be delivered.
- It would be expected that at least some extra units would be delivered and the whole investment would not therefore be considered as risky for the Genco or purchaser/customers. It is a question of balance and judgement
- The regulation setting out longer term norms will be issued soon
- WBERC believes that the cost plus regime will last for some time and that competition should be introduced slowly
- If the regulator required the Genco to provide it with a management plan in relation to its assets this could be considered too intrusive. Generators need to feel the consequences of their own decisions

Damodar Valley Corporation (DVC)

- DVC is expecting to undertake LE R&M works at three 130MW units at Chandrapura power station, which are between 43 years and 39 years old and one 140MW unit at Durgapur, which is 41 years old , through the PiE programme, subject to techno-economic viability
- It is expected that the opportunity will be taken to uprate the Chandrapura units to 140MW capacity.
- 3 additional (more modern) units at Chandrapura may become candidates for R&M at a later date, subject to progress with the initial programme.

Constraints and barriers identified

This section summarises the main constraints or barriers to EE R&M that we have so far identified from our research and from discussion with stakeholders. They include issues related to the energy policy framework and the financial health of the sector, the establishment of a baseline from which to measure improvements that could be made, a series of capacity related issues and issues related to transparency and certainty in the present regulatory framework.

Energy policy framework and financial health

- ***Energy shortages during outage***

  There are two key issues relating to an energy shortage caused by a plant shut down to facilitate an R&M project:

  - the availability of replacement power; and
  - the additional costs of replacement power.

  Both are essentially issues for the distributor, as the purchaser of electricity, rather than the generator. It may be necessary, depending upon contractual agreements, for the distributor to agree to a generator's outage plans.

  Energy outages in India are a serious political and regulatory concern and it is important that R&M projects are not seen to exacerbate the problem, even if they are consistent with longer-term increases in reliability and output. At the overall level, the need for an interruption to existing power supplies is not a factor that characterises new build plant and means that R&M projects are perceived to have an inherent disadvantage.

  To some extent this may be offset if power can be obtained elsewhere, for example, as noted previously in this Annex (the MoP Guidelines for R&M projects) additional power may be made available from the central unallocated pool. However, this provision is at present a little uncertain, as it does not appear to have been activated and, in addition, such power is unlikely to be available at costs as low as that available from state owned generators (running largely depreciated plant).

  Distributors will therefore need to be sure that they can recover the additional costs of the replacement power from customers in their tariffs, absorb the consequential financial losses, and/or receive additional support from the State government in relation to enhanced subsidy levels.

  As noted in the National Energy Policy, "the State Governments need to ensure the success of reforms and restoration of financial health in distribution, which alone can enable the creation of requisite generation capacity." If State Governments do not do this, the financial distress of the distribution sector is likely to represent a significant and continuing barrier to the distributors' willingness to agree to generator proposed outages.

  An alternative option, as is the practice in most competitive markets, would be to make the generator responsible for providing "firm" power under his contract with the distributor, in which case he would be exposed to the risk of power availability and the cost of alternative power during outage periods. There is some reason to consider that generators (or possibly even traders) may be in a better position to manage such costs and to pass them on to distributors in a form of "risk premium."

It has been suggested that it could be possible for the costs of replacement power to be included in the capital costs of a project and potentially annuitised, in order to spread the increased costs over a longer period of time, perhaps equivalent to the period over which the expected benefits of enhanced efficiency would occur. This kind of service would also be more akin to the type of solution that might be expected in a competitive market.

A further issue is the extent to which it can be recognised, within the regulatory framework, that a failure to invest in EE R&M at a time of state power shortages effectively imposes extra costs on the Discom (and potentially on the State Government) through the need to import power. In considering alternative policy and economic options and the costs of a "do nothing" scenario, it is also possible that these costs could be taken into account and compared with the additional volumes that would be generated in a post EE R&M scenario.

These issues are illustrated further in a later part of this Annex and in the main report.

- ***General financial distress of state electricity sector***

  There is still considerable financial distress in the state electricity sector in India, especially at the distribution level and especially as a result of continuing low levels of collection. The National Electricity Policy indicates that State Governments should take measures to ensure the financial health of distribution companies. The failure to propose R&M projects may result in part from political opposition to increased tariffs and from opposition to increased subsidy requirements (resulting from the enhanced capitalisation) even where this is assessed by the regulator as likely to lead to more efficient generation and a more reliable supply.

  To some extent it may be argued that such opposition is also likely in relation to additional new build capacity, but it is clear that, in some respect, the benefits of new build capacity are more certain. In addition, there is also the additional matter that new build projects may attract considerable political kudos

Establishing a baseline for improvement

- ***Energy efficiency policy barriers and lack of orientation***

  The Energy Conservation Act provides that the Central Government may prescribe energy consumption norms for electricity generating companies, force inefficient companies to carry out energy audits and require that they "take appropriate measures" to increase energy conversion efficiency in their operations. The Partnership in Excellence (PiE) programme also provides for extensive use of energy audits.

  In practice the ability to direct generators to carry out energy audits does not appear to have been used, though some have been carried out under the PiE programme and some generators may have carried out their own audits.

As summarised above the Appellate Tribunal for Electricity has instructed that consultants should be appointed to carry out a study of heat rate improvements (that could be achieved by Mahagenco). This would necessarily involve a heat rate audit and may prove to be a precedent that will encourage wider use of energy audits in the future.

- ***Accurate measurement of coal inputs***

A related issue is the question of the measurement of coal quality. At present it would appear that coal deliveries received at power station are not systematically and accurately measured, with billing on the basis of the coal producer's records of train loading, rather than the generator's records of coal received.

It has been suggested to us that the calorific value of delivered coal is often not as high as that claimed and that coal deliveries can contain an unacceptably high proportion of extraneous material. This causes a number of problems, including:

- Very poor combustion causing high carbon in ash and PFA and low boiler efficiency;
- Poor Steam Cycle Terminal Condition of pressure and temperature reducing output and increasing HR;
- Poor steam evaporation causing reduced output and thus HR;
- Increase Secondary Fuel Combustion for flame stabilisation; and
- Increased Auxiliary Power owing to increasing CHP and AHP running

Uncertainty in relation to the volume and quality of coal delivered makes it difficult to establish an accurate benchmark figure for station efficiency. Thus there is a potentially large margin of error in terms of the accurate measurement of improvements made through an EE R&M programme.

Capacity related issues

- ***Genco project development capacity***

The Partnership in Excellence programme provides that inefficient generators may work in partnership with NTPC or another strong generator. It identified 26 poorly performing stations for immediate stabilization (to bring the load factor to a level of around 60%). Of these 26 stations, 17 have signed agreements with NTPC, whilst 1 signed an agreement with Tata Power. The other 8 either opted for self-improvement or were found to be no longer economically viable. In addition, training on O&M practices will be provided as part of the broad World Bank/GEF programme of support.

Of 34 projects identified for LE under the 10th Plan, where work was completed, in progress, or where an order for works had been placed, the leading company alone was responsible for 12 projects and only 8 Gencos were involved, indicating a limited scope of project development capacity.

State generating companies added approximately 18,000MW of new capacity in the period from 2001 to 2006 and more has been added in the last year. This suggests that project management skills may be more widespread than illustrated by the incidence of LE projects alone.

Overall however, the state generators' project management experience and skills appear to be concentrated in relatively few companies and there are a number of generating companies with little or no demonstrated project management and project appraisal experience, which may present a barrier to the development of EE R&M projects.

- ***Generator O&M practices and internal management capacity***

There is a strong belief amongst state regulators that state owned generating companies have a limited ability to operate and maintain their plant effectively, operate poor measurement and monitoring systems and are characterised by poor accountability, leading to a situation where deterioration of performance is the inevitable result, in spite of periodic investment.

Recent reviews by World Bank consultants of WBPDCL and Mahagenco indicated that positive developments were evident, particularly in the Total Quality Management (TQM) system and focus on output exhibited in Mahagenco and certain projects in WBPDCL. However, the consultants also found that Human Resources and Finance and Accounting (especially cost accounting, planning and resource allocation, and management reporting) are areas of inadequacy that need to be addressed. Having said that it is also acknowledged that to some extent human resource practices in particular may derive from State level policies and practices that are outside the direct control of the company's management.

In addition, the World Bank consultants specifically recognised that there are some problems outside of the generators' control, for example in relation to coal quality.

This suggests that in time, with ownership support and with sufficient and appropriately targeted regulatory incentives and appropriately set operating norms, O&M practices at state owned generating companies should improve and that expenditure on R&M will provide continuing benefits.

- ***Contractor capacity and appetite for R&M projects***

During the Inception Mission generators unanimously reported that a significant problem in the market was the limited availability of contracting capacity to support R&M projects. There is a reasonable number of companies with experience of power plant maintenance or refurbishment contracts (around 13 companies are active, as listed in this Annex). It is reported however that the current new build programme, both from IPPs and the projected new state generating company projects, together with the scale of the R&M programme, may mean that contractors do not have the "appetite" or resource capacity to complete a large number of additional R&M projects.

This is exacerbated by the fact that renovation and retrofit work is more difficult to undertake and poses greater risk for a contractor than new build plant. In turn this results from the need to interface with old plant and systems and questions of doubt in relation to the plant history and condition. In addition, there is an inevitable desire by generators to ensure that their performance will continue to reach or exceed the regulatory norms, or to transfer the risks of failure to the contractors. In order to offset this risk a contractor may seek one or more of the following:

- a higher price to offset the increased risk;
- an input to the design of the R&M programme to offset risk by ensuring that the generator undertakes a (potentially more expensive and possibly over-engineered) full R&M programme, rather than a piecemeal approach;
- an ongoing management contract that would offset the generators risk in relation to guarantees of future performance and share the benefit of any performance enhancement; and
- limits on liability.

Further observations in relation to the benefits and risks of contracting out are set out later in this Annex. In setting out our detailed recommendations for the main report we will carry out further investigations in relation to the contractors' appetite and capacity to undertake R&M work. Additional observations on the framework for contracting out and potential private sector involvement are also set out later in this Annex and are further developed in the main report.

- ***Regulators' capacity to assess proposed EE R&M projects***

The State Commissions advocate the use of least cost approach for the determination of the allowable power purchase cost for the Discoms. The Commissions either in their tariff orders or in their Power Purchase regulations have provided for merit order purchases from all sources of supply. In this context, the Commissions have to evaluate the economic feasibility of the option of EE R&M of existing inefficient generating station for additional energy supplies against other options of supply.

To be able to use above the least cost approach an understanding of the generation planning concepts is required. This requires the capability to use various principles and methodologies for forecast of hourly demand curves, knowledge of technical and cost characteristics of various fuel types of generators to meet the projected demand, the ability to determine the cost of unserved energy of various consumer categories, the capability of modeling the environmental impact of various supply options and the capacity to estimate loss of load probability for determining the generation reserve requirements are necessary.

The Capability for interpreting the results of load flow analysis for existing and proposed transmission lines for the least cost siting of a power plant is also required.

In the cost plus regime the Commission is also required to approve the project cost for which the capacity to scrutinize detailed engineering and technical investigations done by the generator as part of Residual Life Studies for establishing the scope (in terms of capital cost and the possible improvement in operating parameters) of the R&M project is required.

Similarly the Commissions need to be equipped to scrutinize/interpret the results of energy audit for establishing base line data, plant specific operating norms and improvements possible in norms over the tariff period.

Presently most of the Commissions are not adequately staffed (or possess the capability) to fulfill the above requirements, but these deficiencies can be overcome through the use of external consultants. The Commission need to procure appropriate softwares, which are available in the market for meeting their requirements.

Regulatory transparency and certainty

- ***Regulatory guidelines for R&M projects***

At present guidelines for R&M projects exist in the form of:

- Central Government (MoP) policy for PFC funding of R&M works. These require a generator to prepare an R&M proposal, including an assessment of benefits, in association with a consultant and then to submit this to the CEA for clearance); and
- statements contained in the National Electricity Policy, the Tariff Policy and the CERC and state regulators' tariff regulations, in relation to depreciation of assets and the debt/equity ratio for additional capitalisation.

In addition, we understand that the CERC intends to issue guidelines on life extension (though these are not expected to cover station heat rate issues).

However, even though an assessment of benefits is required to be undertaken and approved by the CEA as part of the PFC funding programme, there is no certainty that this will be acceptable to the CERC, or to a state regulatory authority, for tariff calculation purposes.

A few regulators, including MERC, have provided for "in principle" ex-ante expenditure approval in relation to R&M projects and UPERC has also indicated that it will consider clean development mechanism (CDM) benefits and costs in tariff computations. However, in most cases, regulators still use an ex-post "prudency check" and in practice there is little practical experience and even less transparent guidance in relation to the assessment of EE R&M project costs and benefits.

It is not perhaps surprising that there is little transparent guidance. Costs and benefits are always likely to remain at least partially subjective. Similarly, Regulators will not usually wish to "fetter their discretion" in a manner that might make it difficult to reflect balance of interests at the time the project is proposed for inclusion in tariff rates, rather than the time it is first considered..

It is the responsibility of the Gencos to propose projects, together with a proper assessment of the potential benefits, for scrutiny by the state regulators. In practice however it is clear that there is some form of impasse that is acting as a barrier to EE R&M projects and that is restricting the number of EE R&M projects proposed by state owned Gencos. It is therefore our view that transparent guidance published by state regulators, taking due account of the proposed CERC guidelines, may help to resolve the problem. .

- ***Pro-active asset management***

  As stated above, there is at present little in the way of published guidance for the assessment of R&M projects. However, neither is there any general requirement in the regulatory framework for a generator to pro-actively review the case for R&M in his generation portfolio. In spite of positive national policy statements and a reasonable funding programme, most generators appear to be permitted to be largely reactive entities, that are permitted to identify and present projects if they so choose, but that are under no compunction to do so. The exception is an Order was made to this effect by UPERC and summarised above.

  We understand this approach, given the objective of introducing competition to the Indian generation market, as it replicates the pressures that a generator would experience in a fully competitive market. However, it does appear that there is something of a discord between the objectives of policy in relation to the immediate requirements of energy efficiency, the environment and security of supply and the medium term objectives in relation to competition.

- ***Operating norms***

  As described above, the present MYTO frame work provides for benchmarking of operating parameters set for the control period. However, although benchmarking of operating parameters is a key issue in relation to the incentivisation of R&M projects (and necessarily requires a high degree of subjective judgement) it is not clear that the present regulatory framework, or its application, takes sufficient account of the variety of circumstances that can apply.

  For example there may be unanticipated variations in performance resulting from the quality of the base line data (the starting point of the plant, ideally based on an energy audit) and plant specific factors, such as:

  - the design performance of the unit (this will differ for example for LMZ compared with KWU manufactured units);
  - the history of the plant, especially problems that have arisen in the past and the past maintenance programme;
  - degradation;
  - plant availability and load factor;
  - fuel supply and quality – for example, whether bituminous, lignites, low CV, presence of extraneous materials, moisture levels, hardness etc;
  - cooling water arrangements; and
  - ambient conditions

  Rather, the application of the present rules appears to use benchmarked norms as something that all plant should be able to attain, given sufficient commitment and appropriate capital expenditure and within a relatively short period of time, on the basis of a performance trajectory that would typically last for the period of the control.

This raises two potential problems. Firstly, the norms are generally set by regulators at the same level for existing (old) and for new plant, whereas our discussions with CERC suggest that CERC accepts that "realistic" norms should be set for older plant. Discussions held with Steag and with the CEA indicate that both also accept that there will be degradation in plant performance over time. Steag felt that this could be recovered at periodic overhaul, whilst CEA felt that there would be a small percentage (0.2%) that was not recoverable. Potentially this could lead generators to favour the greater certainty offered by new build plant.

Secondly, the generator will typically be set a trajectory to reach the set norms over a relatively short time frame, equal to the duration of the price control. In the event that the generator is able to out-perform the target it would therefore retain the incentive benefit only for a short period.

This kind of "one size fits all" approach appears to be distrusted by generators, who face considerable downside risks if their performance falls below the norms set by the regulators.

In addition, because they too face risks in relation to allowing capital expenditure that may not result in the anticipated level of performance improvement regulators appear to prefer a cautious approach to R&M projects. They may for example require generators to provide performance guarantees before approving the recovery of R&M costs.

Such performance guarantees are generally unavailable from contractors, who will not take the risk that performance will deteriorate because of a failure resulting from the subsequent operation of the plant by the Genco. Further comments in relation to contracting out of R&M works are set out later in this Annex.

More detailed comments on operating norms are set out in Appendix 3 to this Annex.

- ***Incentivisation***

  A generator can retain benefits if it outperforms the operating and cost norms allowed in the fixed cost element of its price control, for the duration of that price control period. Variations in uncontrollable costs are passed on to distribution companies/customers, through fuel cost adjustment clauses.

  In order to ensure that the benefits of enhanced efficiency are passed on to customers, operating norms for subsequent price controls would normally be restricted, to take account of actual performance levels achieved, following the completion of the R&M project.

  In theory this provides for a sharing of the benefits of R&M projects. In practice however the generator will have a far stronger incentive to undertake R&M projects in the early period of a price control and a relatively weak incentive to do so during the latter years of a control.

Given that regulators in India are at present mostly in the early stage of applying a multi-year tariff framework and that controls tend to be implemented for only around 3 years, this means that the incentive for the generator is relatively low. This may change in the future as India progressively moves to 5 year (or potentially longer) price control periods.

Two recent developments have indicated that some regulators appreciate the nature of the short-timescale problem and are prepared to be flexible. One is the extension of the forthcoming tariff control period in West Bengal to 8 years. The other is the extension of an existing price control period in Uttar Pradesh by one year (applicable to an R&M project only).

There are a number of alternatives that might provide a stronger incentive and greater certainty for generators whilst dovetailing with the existing price control framework. We will consider these in proposals to be put to the Workshop that will be held in early May.

It is also worth noting at this stage that it may be possible to link the incentive to the duration of a distributor's power purchasing review, extending over a timeframe of potentially 10 years, or even longer.

More detailed comments on the scope for improvement to heat rates and incentivisation are set out in Appendix 5 to this Annex.

- ***Modification of tariff control***

  The existing regulations (for example 18 (4) of the CERC tariff regulations) limit the number of tariff revisions that may be made during a control period.

  This has two effects that may act as barriers to the development of R&M projects:

  - it constrains the submission of R&M projects (and resulting additional capitalisation) into a limited timeframe; and
  - it restricts the adjustment of allowed revenues, for example if operating norms require to be adjusted to take account of unanticipated factors.

- ***Recovery of fixed costs***

  Tariff regulations usually provide for a pro-rata reduction in a generator's fixed charges if availability falls below the normative level, with no fixed charge payable at zero availability. This mimics the commercial position in a competitive market, but could damage the cash flow position of the generator undertaking R&M works and act as a significant disincentive to R&M.

Conclusions

Above we have set out the main barriers and constraints identified to EE R&M projects. Our initial conclusions in relation to each are summarised in turn below.

- ***Energy policy and the financial health of the sector***

It is clear that electricity policy in India recognises the importance of EE R&M. A funding plan for LE works (that provide an opportunity for EE R&M) has been identified and policy instruments exist that appear to ensure that energy audits are carried out. However, there appear to be 3 particular problems:

  - there is something of a dischord between policy and practical (political) reality at the state level. Concerns about the cost of R&M and its impact on end-use customer prices appear to counteract the desire to protect the environment, ensure the efficient use of resources and enhance India's fuel security and system reliability. As a result, although concerns about price impacts may be overcome by the political kudos and more certain environmental, efficiency, security and reliability benefits of new build plant, it is possible that they may not be sufficiently counteracted in the case of R&M works;
  - there appears to be a failure to transfer stated policy intent into reality. In practice, there appears to have been little use made of the provisions of the Energy Conservation Act, in relation to energy audits and, for the most part, generators appear to be under no particular compunction to propose or deliver R&M projects. Instead they appear to be (permitted to be) essentially reactive, perhaps because regulators do not wish to interfere in management decisions in a manner that might be regarded as intrusive and out of sync with the impacts of a competitive market; and
  - it is clear that the Discoms face the costs of higher priced power that must be imported during any plant outage necessary to enable EE R&M works to be undertaken. Similarly, in a situation of shortage, the Discom would face the additional costs/risks of a generator's failure to make an investment in an EE R&M project. The costs of such decisions should be taken into account in a regulator's overall economic appraisal of the benefits of an EE R&M scheme and this is not something that the regulator can rely on the Genco to provide. Potentially additional short-term power purchasing could be annuitized. This is illustrated and explored further later in this Annex.

- ***Establishment of the baseline***

  Issues related to the establishment of a clear and accurate baseline for measuring the benefits achieved through EE R&M projects are crucial. With PLF focussed improvements, that have been the primary objective of R&M activities so far, it is clear what benefits are achieved through R&M works.

  Heat rate improvements on the other hand are more difficult to manage and suffer from a greater number of uncertainties. The appointment of consultants (as recommended by the ATE in the case of Mahagenco) and greater certainty in relation to coal quality will also remove some of the uncertainty. It may also provide regulators with greater confidence to set hear rate trajectories that reflect the possibilities and idiosyncracies of specific stations, or even units.

- ***Technical and management capacity***

  There appears to be little doubt, from independent studies undertaken for the World Bank, that project management and managerial capacity amongst state owned Gencos in India is sub-optimal, although there are clear instances of success. However, it also appears to be the case that things are changing and that real steps are being taken by state owned generators to quickly enhance their performance. Given the track record of some state owned generators (such as UPRVNL and APGenco) and with support from technical advisers/consultants and demonstration projects, it would not appear that this should represent an insurmountable barrier to the successful implementation of energy efficient R&M projects.

  A more intractable problem and one that may ultimately determine the pace of R&M development in India, is that presented by the lack of contractor capacity and lack of appetite for R&M projects. We will examine this issue further in our later reports and recommendations.

- ***Regulatory transparency and certainty***

  The final group of barriers to successful energy efficient R&M projects is contained in the present regulatory framework. The system is designed to provide incentives to enhanced performance by generators, including incentives to outperform norms through R&M work. However, with some exceptions (such as the UPERC Order to UPVRN summarised later in this Annex) it does not force Gencos to actively manage their plant portfolio.

  From the regulator's side there is an information asymmetry problem and norms must therefore be set (on the basis of the best available information) that are stretching, but achievable for generators. Our comments in respect of baselining efficiency improvements that can be achieved through EE R&M schemes are relevant in this respect.

  From the generator's perspective, although regulators complain of information asymmetry, the system itself is felt to exhibit asymmetric risk sharing. Price controls are of relatively short duration (with one or two recent exceptions) but there is an expectation that norms will be tightened (and benefits passed to customers/distributors) if there is outperformance. Therefore the incentives for outperformance are relatively weak, especially if EE R&M projects have payback periods of more than a few years. In addition, the risk of a failure to achieve the set norms, as a result of poor quality coal, degradation factors or other factors beyond the generator's reasonable control may result in a financial penalty on the generator.

  Although these problems should not be intractable, with a strong will on both sides and with clarity in relation to the baseline, there appears at present to be an overall lack of mutual trust and respect between regulators and state owned generators.

  Of course, there will always be some "noise" around this issue, but it does not appear to represent a serious flaw in the regulatory system. Rather it appears to us that the regulatory system needs to recognise and be seen to recognise the need for a series of small but important adjustments to the present system. Some regulators are already taking important steps towards recognising the need for a more balanced sharing of benefits and this is a very important development. A number of other small but important recommendations to the energy purchasing framework, the setting of norms and the need for a more transparent framework for assessing costs and benefits of R&M projects are set out later in this Annex.

ANNEX 5 – INDICATIVE BENEFIT ANALYSIS

- ***Potential for reduced fuel consumption***

It is possible to make a number of different assumptions and scenarios in relation to coal savings from EE R&M projects.

In order to illustrate the potential level of fuel saving that can be obtained if the same total volume of electricity is to be generated, we have assumed the following:

- most of the units suitable for EE R&M are now 210MW units
- coal to be burned is of "reference quality" with a c.v. of 4,100 kcal/kg
- the heat rate improvement from EE R&M would result in a decrease in specific coal consumption from 0.8kg/kWh to 0.62kg/kWh

On this basis our calculations indicate an annual saving of around 280,000 tonnes of coal for a single 210MW plant, as illustrated in Table 2.

Annex 5, Table 1 – illustrative coal savings from EE R&M for a single 210MWplant

	Base case (pre EE R&M)	**Post EE R&M**	**Units**
Coal quality	Reference	Reference	
Nameplate capacity	210	210	MW
Installed (effective) capacity	200	210	MW
Plant Load Factor (PLF)	50%	80%	Percent
Heat Rate (SHR)	3300	2500	kcal/kWh
Calorific value of coal	4,100	4,100	kcal/Kg
Specific coal consumption	0.8	0.61	Kg/kWh
Annual output	876,000	1,471,680	mWh
Additional output	n/a	595,680	mWh
Coal consumption	700,800	897,725	Tonnes
Equivalent coal consumption @ base case efficiency	n/a	1,177,344	Tonnes pa
Coal saved	**n/a**	**279,619**	**Tonnes pa**

If coal savings on this scale were to be replicated in only around 25% of the 38,000MW of capacity owned by State generating companies, this would bring total annual coal savings to India of approximately 12.6 million tonnes per annum.

9,500MW/average 210MW unit size x 280,000 tonnes = 12.6 million tonnes per annum

This is approximately 15% greater than India's total coal imports for power station use in 2005/6 (quoted by the CEA as 10.4million tonnes).

If we assume that a much higher proportion of inefficient coal fired plant were to be subject to EE R&M schemes, say 30,000MW, then the coal savings would be around 40 million tonnes per annum. This would be well in excess of current import levels and would significantly aid the conservation of India's coal stocks for the future.

30,000MW/average 210MW unit size x 265,000 tonnes = 40 million tonnes per annum

It should be noted that the level of saving in indigenous coal burn and the conservation of India's resources would be even greater if we assume a lower quality coal. This might not result in an equivalent tonnage saving of imported coal, because of the generally higher calorific value of imported coal.

- ***Reduction in generation shortfall***

  An alternative view of the benefits of EE R&M is to consider the additional volumes of power generated by rehabilitated and modernised capacity operating at greater efficiency levels than before.

  We have assumed for this purpose that a comprehensive EE R&M scheme for a poorly performing plant would necessarily involve life extension and other works, but would also incorporate a range of measures targeted at increasing the heat rate (returning it to design or near design levels). It would also ensure a reduction in specific coal consumption above and beyond that which might be achieved through the increase in load factor alone. (An increase in Plant Load Factor (PLF) from 50-% to 80% might be expected to result in a 10%-12% increase in heat rate, say from around 3300 kcal/kWh to around 2900 kcal/kWh, but EE R&M measures would be designed to take the plant to nearer its design capability, for example to normative levels, or potentially even better).

  On the basis of the same assumptions as the calculation of potential coal savings, an additional 596,000mWh can be generated by the same power single 210MW power plant post EE R&M works, as indicated in Table 3.

Annex 5, Table 2 – illustrative additional output from EE R&M for a single 210MW plant

	Base case (pre EE R&M)	**Post EE R&M**	**Units**
Coal quality	High cal	High cal	
Nameplate capacity	210	210	MW
Installed (effective) capacity	200	210	MW
Plant Load Factor (PLF)	50%	80%	Percent
Heat Rate (SHR)	3300	2500	kcal/kWh
Annual output	876,000	1,471,680	MWh
Additional output	**n/a**	**595,680**	MWh

This is an increase of 68% over the pre-R&M output levels from the same station.

If the additional generation output was able to be obtained from only around 25% of the capacity owned by State generating companies this would result in around 26,900,000 MWh, or an additional 26.9 TWh of additional generation output.

9,500MW/average 210MW unit size x 595,680 MWh = 26.9 TWh per annum

This would amount to around 5.4% of India's total consumption of approximately 500TWh and would significantly reduce India's generation shortfall.

If we assume that a much higher proportion of India inefficient coal fired plant were to be subject to EE R&M schemes, say 30,000MW, the additional generation output would be approximately 85TWh. This is equivalent to around 17% of India's present consumption, somewhat greater than the present deficit.

30,000MW/average 210MW unit size x 595,680 MWh = 85.2 TWh per annum

- ***Other benefits***

In addition to savings in coal burn and/or additional generation output, depending on how those benefits were to be taken, there are certain other benefits from comprehensive EE R&M schemes, including:

- reductions in specific oil consumption; and
- reductions in auxiliary consumption.

These are illustrated in Table 4.

| Annex 5, Table 3- typical benefits from comprehensive EE R&M schemes

	Base case (Pre-EE R&M)	**Post EE R&M**
Specific oil consumption	6ml/kWh	2ml/kWh
Auxiliary power consumption	14%	9%

However, it can be difficult to distinguish improvements due to EE R&M as opposed to improvements that can be obtained from life extension and other works that would enhance plant load factor, so we have not focussed on these in this report.

Of course there would also be significant savings in emissions, if the benefits of enhanced efficiency were taken as a reduction in coal burn. However, because these cannot be incentivised through the existing framework for economic regulation in India we have not concentrated on the environmental aspects of enhanced efficiency in this report.

- ***Potential heat rate improvement projects***

Annex 5, Table 4 – potential heat rate improvement projects

Item	Cause of loss	R&M works	Benefit	Estimated Cost	Risk
Fuel					
Fuel Quality	Low CV	Additional milling capacity and improved design	Medium	High	Medium
	High Moisture	Minimise as delivered and stock moisture - due to monsoon, washing or dust suppression	Medium	Medium/High	Medium
Boiler Loss					
Dry Flue Gas Loss	Airheater Blockage	Replace Elements	Medium	Medium/Low	Low
	Airheater Seal Leakage	Replace Seals and Dampers	Medium	Low	Low
	High Gas exit temperature	Improve soot-blowers	Low	Low	Low
	High Gas Flow	Furnace and Duct Leaks - repairs	Low	Low	Low
Carbon in FBA/PFA Loss	Poor Mill Grinding throughput	Replace or Overhaul Mills	Medium	Medium/High	Low
	Low PF Temperature	Modify Air Heater - see above		Medium/High	Medium
	Poor Combustion	Fit renew or overhaul new PF classifiers	Medium	Medium	Medium
	Poor Combustion	Improve PF Distribution	Medium	Medium	Medium
	Poor Combustion	Improve PF Burners	Medium	M/H	Medium
	Lack of Combustion Air	Fan performance, (Airheater see above	Medium	High	Medium
Radiation and Unaccounted Loss	Poor Lagging	Repair /replace lagging	Low	L	Low
Superheat Pressure Loss		Improve boiler design, improve combustion performance (see Carbon in PFA above)	Low	High	High
	Passing valves	Repair/replace valves	Low	Low	Low
Superheat Temperature Loss	Poor combustion, poor design	Improve boiler design, improve combustion performance	Medium	High	High
Reheat Temperature Loss	Poor combustion, and design	Improve boiler design, improve combustion performance	Medium	High	High
Steam Water Cycle					
Condenser Vacuum Loss	Air Ingress	Reduce Air Leakage	High	Low	Low
		Improve Air Pump Performance – renew /repair	High	Low	Low

Item	Cause of loss	R&M works	Benefit	Estimated Cost	Risk
	CW Flow Low	Fit tube cleaning equipment (taprogge)	Medium	Low	Low
	CW Flow Low	Additional off load cleaning	Medium	Low	Low
	CW Flow Low	Repair/replace CW pumps	Low	Medium/High	Medium
	CW Temperature High	Improve Cooling Tower performance (if fitted) – new packs etc	Low	Medium/High	Medium
	CW Temperature High	Fit additional CT	Medium	High	High
Final Feed Temperature Loss	Heater OOS – tube leaks	Replace heater	High	Medium	Low
	Heater Bypassing	Repair valves and baffles	Medium	Low	Low
Make Up loss	MU Water Quality	WTP modifications to ensure correct quality	Low	Low	Medium
		Reduce Condensate Contamination) – renew condenser	Medium	High	Low
		Reduce Condensate Contamination) – repair condenser	Low	Medium/Low	Low
		Improve chemical monitoring -Optimise blowdown regime	Low	Low	Low
	Passing Valves	Repair /replace valves, levels controls etc	Low	Low	Low
	Sootblowing	Optimise sootblowing regime	Low	Low	Low
Turbine					
HP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low
IP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low
LP Cylinder Loss	Low Cylinder Efficiencies	Overhaul	Medium	Medium	Medium
	Low Cylinder Efficiencies	Fit modified blades and diaphragms	High	High	Low

1. ***Cost assumptions***
   - ***Low*** ***<US$250***
   - ***Medium*** ***>US$252- <US$1m***
   - ***High*** ***>USD1m***

2. ***Risk assumptions – are based on the likelihood of project/works achieving the desired performance objectives.***

- ***Benefits***

Additional savings would be expected in relation to oil consumption and auxiliary power, though we would expect these to be of a lower order than the coal cost savings.

Annex 5, Table 5 – illustrative coal savings compared with norm –reference cv coal

Annual coal savings			
	Base case (pre R&M)	**Post EE R&M**	**Units**
Coal quality	High cal	High cal	
Nameplate capacity	210	210	MW
Installed (effective) capacity	210	210	MW
Plant Load Factor (PLF)	80%	80%	Percent
Heat Rate (SHR)	2500	2375	kcal/kWh
Calorific value of coal	4,100	4,100	kcal/Kg
Specific coal consumption	0.61	0.58	Kg/kWh
Annual output	1,471,680	1,471,680	mWh
Additional output	n/a	0	mWh
Coal consumption	897,725	853,574	Tonnes
Equivalent coal consumption @ base case efficiency	n/a	897,725	Tonnes pa
Coal saved	n/a	44,150	Tonnes pa

Annex 5, Table 6 – illustrative coal savings compared with norm – low cv coal

Annual coal savings			
	Base case (pre R&M)	**Post EE R&M**	**Units**
Coal quality	High cal	High cal	
Nameplate capacity	210	210	MW
Installed (effective) capacity	210	210	MW
Plant Load Factor (PLF)	80%	80%	Percent
Heat Rate (SHR)	2500	2375	kcal/kWh
Calorific value of coal	2,500	2,500	kcal/Kg
Specific coal consumption	1	0.95	Kg/kWh
Annual output	1,471,680	1,471,680	mWh
Additional output	n/a	0	mWh
Coal consumption	1,471,680	1,398,096	Tonnes
Equivalent coal consumption @ base case efficiency	n/a	1,471,680	Tonnes pa
Coal saved	n/a	73,584	Tonnes pa

On the basis that such benefits could be obtained over a 15 year period and allowing for a progressive straight line deterioration in heat rate over the 15 year period (from 2375kcal/kg to the 2500 norm, with an increase in coal consumption of around 4%) - for indicative purposes only - the total financial benefit from the coal saving would amount to around $18m, as shown in Table 8.

Depending upon the regulatory treatment of the marginal expenditure to ensure EE R&M, over and above the costs of LE and other R&M work to support PLF enhancements (which are very difficult to quantify) this benefit could be fully retained by the generator as an incentive, or shared with customers, through a modification to the norms, or some other mechanism.

If, for example, the generator was permitted to retain the benefit for the first 7 years of an MYTO and assuming the marginal cost of the investment was \$5m, the generator could retain around \$6.7m, leaving a further \$6.3m to be subsequently returned to customers through an adjustment in the norms. Further work is necessary in order to establish the precise marginal costs of an EE R&M scheme, although we have indicated the typical range of costs for EE R&M works.

Annex 5, Table 7 – illustrated benefits to generator from EE R&M scheme – life of project

Year	MW	PLF	Units	HR	Total Heat	Coal CV	Coal PA	Coal at 2500 SHR	Coal saving
						kcals/tonne	tonnes		
1	210	0.8	1471680	2375	3.49524E+12	2500000	1398096	1471680	73584
2	210	0.8	1471680	2382	3.50573E+12	2500000	1402290	1471680	69390
3	210	0.8	1471680	2389	3.51624E+12	2500000	1406497	1471680	65183
4	210	0.8	1471680	2396	3.52679E+12	2500000	1410717	1471680	60963
5	210	0.8	1471680	2404	3.53737E+12	2500000	1414949	1471680	56731
6	210	0.8	1471680	2411	3.54798E+12	2500000	1419194	1471680	52486
7	210	0.8	1471680	2418	3.55863E+12	2500000	1423451	1471680	48229
8	210	0.8	1471680	2425	3.5693E+12	2500000	1427722	1471680	43958
9	210	0.8	1471680	2433	3.58001E+12	2500000	1432005	1471680	39675
10	210	0.8	1471680	2440	3.59075E+12	2500000	1436301	1471680	35379
11	210	0.8	1471680	2447	3.60152E+12	2500000	1440610	1471680	31070
12	210	0.8	1471680	2455	3.61233E+12	2500000	1444931	1471680	26749
13	210	0.8	1471680	2462	3.62317E+12	2500000	1449266	1471680	22414
14	210	0.8	1471680	2469	3.63404E+12	2500000	1453614	1471680	18066
15	210	0.8	1471680	2477	3.64494E+12	2500000	1457975	1471680	13705
							21417617	**22075200**	**657583**
								Financial saving	**\$18,083,524**

Therefore, over a medium term time frame, significant financial incentives could exist for generators to pursue EE R&M schemes, within the framework of the present regulatory system. In addition, there is the possibility of interest rate subsidies from the PFC.

However, although EE R&M investments appear to be permissible under the present regulatory framework, it is probably fair to say that EE R&M is not an integral requirement of the regulatory framework, rather it has the characteristics of a "bolt-on" consideration. We believe that the typical coal savings demonstrated above suggest that it should no longer be a "bolt on" but an integral part of LE schemes and of R&M schemes designed to enhance plant load factor.

Need for additional incentives

At the end of 2006, CEA figures indicate that LE works (which provide the greatest opportunity for EE R&M at a marginal cost) had been completed, were in process or had been ordered at 33 units, representing 5,338MW (51%) of the total 10,413MW of plant identified for LE works in the 10th National Plan. Works at the residual units had either been transferred to the PiE programme (21 units with a capacity of 2203MW) or were noted as “expected to be completed” during the 11th NEP (28 units with a capacity of 3012.5MW).

However, despite the scale of this programme and despite indications that between 25,000 and 30,000MW of plant are in need of substantial upgrade, to improve plant life, load factor and heat rate, to the best of our knowledge, few, if any EE R&M projects have been proposed.

In order to stimulate debate between regulators, generators, distribution companies and other relevant stakeholders, Tables 9 and 10 set out a high level analysis of the potential costs and benefits of comprehensive EE R&M/LE/PLF enhancement projects, including additional units that might be generated, potential coal savings and indicative output costs.

These are illustrated on the basis of new build or EE R&M benefits obtained through operation at norms, rather than at design heat rate and in practice therefore we would expect further benefits to accrue for EE R&M and new build plant, when compared with the Base Case “do nothing” option.

Perhaps contentiously Table 10 includes an assessment of the total costs to the system, considering savings that might be made by Discoms in purchasing from plant subject to R&M, compared with the ongoing costs of importing power from the Central Pool.

The notes to the Tables indicate the assumptions we have made in relation to the costs of additional/unserved power. For an EE R&M scheme these represent the additional cost to the Discom of buying power to replace the output of the plant during the period of overhaul/outage. For an existing/Base Case plant that continues to run at low levels of efficiency these costs are assumed to represent the cost to the Discom of buying power in the market, to meet the demand that could be met by a plant subject to R&M but could not be met by a Base Case plant. If it was assumed that the Base Case should include the costs of “fail to serve” power for a longer period, for example 2 years, then the costs of imported power would rise and total costs would increase to circa \$50-\$55. Of course this situation is only of strong relevance to those states, such as Maharashtra, that are suffering from a significant power deficit and will have less relevance to the eastern States.

In so far as possible, these Tables are based on costs that reflect the present situation in India, though a number of broad generalisations have necessarily been used in order to compare one scenario with another, for example in relation to the residual value of a plant pre R&M and in relation to O&M costs.

Nevertheless, it is hoped that the Tables help to demonstrate that EE R&M is a serious option that should be strongly considered alongside new build plant and illustrate the true costs faced by a Discom. These issues, along with a series of options for the way forward in India is further illustrated later in this report.

Figure 4 illustrates the comparative costs of existing (Base Case) plant not subject to EE R&M, compared with a range of EE R&M options and with new build plant, both including and without the estimated costs of imported/replacement power (during the outage period for refit).

The figures, which should be taken for illustrative purposes only, indicate that EE R&M projects can be competitive with new build in solving India's power deficit problem and in terms of reduced coal burn (depending upon how the benefit is taken). Depending on the precise Capital Expenditure costs used, EE R&M projects can also be highly competitive with existing power costs, especially if it is assumed that the performance of the existing plant will deteriorate more rapidly over the lifetime of the EE R&M project. (Such figures are not built into these simple assumptions). Further analysis of EE R&M costs and benefit sharing is set out later in this report.

Annex 5, Table 8 – benefits of comprehensive EE R&M –without cost of replacement power

		Base case without EE R&M			**With EE R&M**						**New build**		**Units**
Notes	Reference	***BC1***	***BC2***	***BC3***	***EE1***	***EE2***	***EE3***	***EE4***	***EE5***	***EE6***	***NB1***	***NB2***	
	Capex assumptions				Std	Std/high cal	Fast refit	Low capex	High return	Std/low cal	Ref coal	Low cal coal	
1	Installation cost	$0	$0	$0	$292,500	$263,500	$263,500	$220,000	$263,500	$263,500	$1,005,885	$1,005,885	US$ per MW
2	Implementation time	n/a	n/a	n/a	0.75	0.75	0.5	0.75	0.75	0.75	2/3	2/3	Years
3	Life of project/residual plant life	5	5	5	15	15	15	15	15	15	25	25	Years
	Nameplate capacity	110	210	210	120	210	210	210	210	210	210	210	MW
	Installed (effective) capacity	105	200	200	120	210	210	210	210	210	210	210	MW
4	Plant Load Factor (PLF)	50%	50%	50%	80%	80%	80%	80%	80%	80%	80%	80%	Percent
5	Heat Rate (SHR)	3300	3300	3300	2500	2500	2500	2500	2500	2500	2450	2450	kcal/kWh - norms
6	Calorific value of coal	4,100	4,100	2,500	4,100	4,100	2,500	2,500	2,500	2,500	4,100	2,500	kcal/Kg
7	Specific coal consumption	0.8	0.8	1.32	0.61	0.61	1	1	1	1	0.6	1	Kg/kWh
8	Project cost/residual value of plant	$3,000,000	$6,000,000	$6,000,000	$35,100,000	$55,335,000	$55,335,000	$46,200,000	$55,335,000	$55,335,000	$211,235,850	$211,235,850	US$
	Annual output	459,900	876,000	876,000	840,960	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	mWh
9	Additional output	n/a	n/a	n/a	381,060	595,680	595,680	595,680	595,680	595,680	n/a	n/a	mWh
10	Coal consumption	367,920	700,800	1,156,320	512,986	897,725	1,471,680	1,471,680	1,471,680	1,471,680	883,008	1,471,680	Tonnes
11	Cost to Discom of imported power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Nil
12	Coal cost - reference coal	$13,797,000	$26,280,000	n/a	$31,536,000	$55,188,000	n/a	n/a	n/a	n/a	$55,188,000	n/a	US$37.5 tonne
12	Coal cost - low quality coal	n/a	n/a	$24,090,000	n/a	n/a	$40,471,200	$40,471,200	$40,471,200	$40,471,200	n/a	$40,471,200	US$27.5 tonne
13	Coal consumption @ base equivalent	n/a	n/a	n/a	672,768	1,177,344	1,942,618	1,942,618	1,942,618	1,942,618	n/a	n/a	Tonnes pa
14	Coal saved	n/a	n/a	n/a	159,782	279,619	470,938	470,938	470,938	470,938	n/a	n/a	Tonnes pa
15	Opex	$3,190,000	$6,090,000	$6,090,000	$3,480,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	US$ pa
16	WACC	14%	14%	14%	14%	14%	14%	14%	20%	14%	14%	14%	Percent
17	Annual return on capital	$420,000	$840,000	$840,000	$4,914,000	$7,746,900	$7,746,900	$6,468,000	$11,067,000	$7,746,900	$29,573,019	$29,573,019	US $ pa
18	Assumed O&M cost	$7	$7	$7	$4	$4	$4	$4	$4	$4	$4	$4	US$ per mWh
	Assumed (residual) depreciation	$1	$1	$1	$3	$3	$3	$2	$3	$3	$6	$6	US$ per mwh
	Fuel cost	$30	$30	$28	$38	$38	$28	$28	$28	$28	$38	$28	US$ per mwh
	Return on capital	$1	$1	$1	$6	$5	$5	$4	$8	$5	$20	$20	US$ per mWh
	Imported power	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	Capitalised
	Total cost	**$39**	**$39**	**$37**	**$50**	**$49**	**$39**	**$38**	**$42**	**$39**	**$67**	**$57**	US$ per mWh

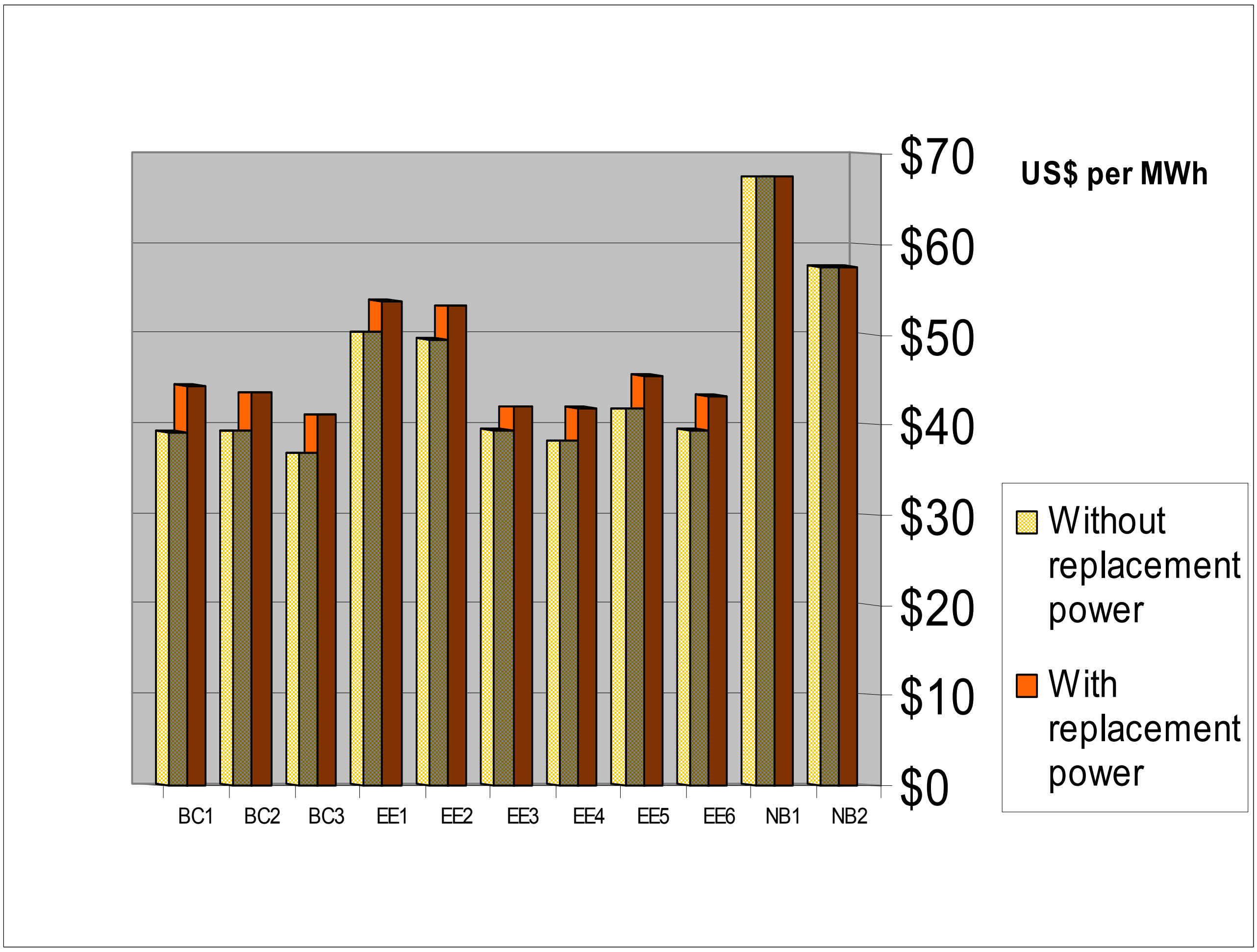
Annex 5, Table 9 – benefits of comprehensive EE R&M – including cost of replacement power

		Base case without EE R&M			**With EE R&M**						**New build**		
Notes	Reference	***BC1***	***BC2***	***BC3***	***EE1***	***EE2***	***EE3***	***EE4***	***EE5***	***EE6***	***NB1***	***NB2***	Units
	Capex assumptions				Std	Std/high cal	Fast refit	Low capex	High return	Std/low cal	Ref coal	Low cal coal	
1	Installation cost	$0	$0	$0	$292,500	$263,500	$263,500	$220,000	$263,500	$263,500	$1,005,885	$1,005,885	US$ per MW
2	Implementation time	n/a	n/a	n/a	0.75	0.75	0.5	0.75	0.75	0.75	2.50	2.50	Years
3	Life of project/residual plant life	5	5	5	15	15	15	15	15	15	25	25	Years
	Nameplate capacity	110	210	210	120	210	210	210	210	210	210	210	MW
	Installed (effective) capacity	105	200	200	120	210	210	210	210	210	210	210	MW
4	Plant Load Factor (PLF)	50%	50%	50%	80%	80%	80%	80%	80%	80%	80%	80%	Percent
5	Heat Rate (SHR)	3300	3300	3300	2500	2500	2500	2500	2500	2500	2500	2500	kcal/kWh
6	Calorific value of coal	4,100	4,100	2,500	4,100	4,100	2,500	2,500	2,500	2,500	4,100	2,500	kcal/Kg
7	Specific coal consumption	0.8	0.8	1.32	0.61	0.61	1	1	1	1	0.61	1	Kg/kWh
8	Project cost/residual value of plant	$3,000,000	$6,000,000	$6,000,000	$35,100,000	$55,335,000	$55,335,000	$46,200,000	$55,335,000	$55,335,000	$211,235,850	$211,235,850	US$
	Annual output	459,900	876,000	876,000	840,960	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	1,471,680	mWh
9	Additional output	n/a	n/a	n/a	381,060	595,680	595,680	595,680	595,680	595,680	n/a	n/a	mWh
10	Coal consumption	367,920	700,800	1,156,320	512,986	897,725	1,471,680	1,471,680	1,471,680	1,471,680	897,725	1,471,680	Tonnes
11	Cost to Discom of imported power	$35,724,375	$55,845,000	$55,845,000	$43,115,625	$82,125,000	$54,750,000	$82,125,000	$82,125,000	$82,125,000	$0	$0	US $125 per mWh
12	Coal cost - reference coal	$13,797,000	$26,280,000	n/a	$31,536,000	$55,188,000	n/a	n/a	n/a	n/a	$55,188,000	n/a	US$37.5 tonne
12	Coal cost - low quality coal	n/a	n/a	$24,090,000	n/a	n/a	$40,471,200	$40,471,200	$40,471,200	$40,471,200	n/a	$40,471,200	US$27.5 tonne
13	Coal consumption base equivalent	n/a	n/a	n/a	672,768	1,177,344	1,942,618	1,942,618	1,942,618	1,942,618	n/a	n/a	Tonnes pa
14	Coal saved	n/a	n/a	n/a	159,782	279,619	470,938	470,938	470,938	470,938	n/a	n/a	Tonnes pa
15	Opex	$3,190,000	$6,090,000	$6,090,000	$3,480,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	$6,090,000	
16	WACC	14%	14%	14%	14%	14%	14%	14%	20%	14%	14%	14%	Percent
17	Annual return on capital	$420,000	$840,000	$840,000	$4,914,000	$7,746,900	$7,746,900	$6,468,000	$11,067,000	$7,746,900	$29,573,019	$29,573,019	US $ pa
18	Assumed O&M cost	$7	$7	$7	$4	$4	$4	$4	$4	$4	$4	$4	US$ per mWh
	Assumed (residual) depreciation	$1	$1	$1	$3	$3	$3	$2	$3	$3	$6	$6	US$ per mwh
	Fuel cost	$30	$30	$28	$38	$38	$28	$28	$28	$28	$38	$28	US$ per mwh
	Return on capital	$1	$1	$1	$6	$5	$5	$4	$8	$5	$20	$20	US$ per mWh
	Imported power	$5	$4	$4	$3	$4	$2	$4	$4	$4	$0	$0	Capitalised
	Total cost	**$44**	**$44**	**$41**	**$54**	**$53**	**$42**	**$42**	**$45**	**$43**	**$67**	**$57**	US$ per mWh

Annex 5, Table 10 – list of assumptions for Tables 8 & 9

	Notes and assumptions to Tables 9 and 10
1	Installation cost - figures for standard capex from Tanda plant for 110MW unit. Assume10% reduction in cost for larger plant and 25% for low capex scenario.
2	Implementation time - assume completed at time of LE works. One example shows benefit of faster completion.
3	Residual life assumed for existing plant and based on World Bank project figures for EE R&M and New Build
4	Plant load factor - assumptions from World Bank project figures
5	Heat rate assumptions from typical average for old plant and CERC norms for new plant
6	Coal cv figures represent reference coal (4,100) and domestic coal typically available (2500)
7	Specific coal consumption figures - IPA/KPMG best estimates and World Bank assumptions
8	Residual life/value of plant based on costs per MW for Tanda TPS (which was in poor condition with plf at 21% preR&M) and IPA/KPMG best estimates
9	Additional output = output of new or refurbished unit minus output of base case unit
10	Coal consumption = specific coal consumption multiplied by output
11	• Cost of imported power for Base Case = cost of additional units that would be generated by a refurbished plant for average 8 month refurbishment period @ Rs5 per kWh market price. If it was assumed that the Base Case should include costs of “fail to serve” power for a longer period, for example 2 years, then the costs of imported power would rise and total costs would increase to circa \$50-\$55. • Cost of imported power for EE R&M plant = cost of units that would have been generated by Base Case plant during period of outage @ Rs5 per kWh market price • No cost of imported power assumed for new build plant but potentially could be equal to cost of lost units during construction if site of old plant is used
12	Coal cost = IPA/KPMG best estimate of price of delivered coal of specific cv
13	Coal consumption base equivalent = coal consumption that would be required by base case plant to generate volume generated by refurbished plant
14	Coal saved = base equivalent consumption minus estimated consumption of refurbished plant
15	IRR = IPA/KPMG assumption, with higher rate for one example to illustrate impact of higher incentive
16	Annual return on capital is IRR times original investment. Simple calculation to illustrate impact and not project lifetime depreciated costs
17	Assumed O&M cost is simple IPA/KPMG figure for illustrative purposes

Annex 5, Figure 1 - Output costs of EE R&M plant, compared with Base Case (existing) and new build



ANNEX 6: SETTING THE NORMS

Operating norms

There is a range of operational issues that cause the heat rate to move off design and that should be taken into account when setting unit and potentially plant specific norms.

Fuel Quality

Fuel quality is a key driver in establishing heat rate performance. It is well documented that Indian coal producers are at best sending variable quality coal to power plants, with some having to cope with very poor fuel and manage the resulting impact on HR. Although design coal is in the range of 3500-5000 kcal/kWh it seems that in practice very few plant in the whole of India receive coal within this range.

Recent data from West Bengal show coals with CV at <1000 kcals/kg, with all in general well below the design coals. These poor coals cause considerable HR losses in pulveriser grinding quality and combustion condition, leading to high carbon in ash, low boiler pressure and temperature etc.

These are made worse by Units having no or little plant redundancy in milling plant and margins on mill throughput of fan power.

The poor fuel also causes more auxiliary power consumption for CHP, AHP, Milling Plant and Boiler Fans, i.e. CHP and AHP have to run up to 100% more hours than design.

Caloric Value Measurement

It is also required to measure the cv of the coal delivered to power station bunkers accurately in order to enable HR calculation, along with the tracking and measurement of coal stocks.

While this is reported to be carried out to the required standards (actual standards being applied are not known at this time) there is very little evidence in the data to show this.

The variability of coals, with no consistency across the rakes (coal train), make it very difficult to establishing an accurate sampling process.

Similarly, accurate measurements of coal stocks are required to validate all data over the long term – 6-12 months. This is also required for financial reporting reasons for working capital adjustments.

Coal Quantity Measurements

There is also debate on the accuracy of coal quantity and thus total heat delivered. There are allowances for losses but the amount of stones, rock and other non combustible material may not be accurately accounted for in the CV measurements above

Degradation

Some degradation of plant will be irrecoverable, whilst some recovery will be seen after maintenance.

With regard to steam turbine plant the effect of short-term degradation occurs within two years, is non-recoverable and is typically in the order of 2-2.5 %. Long-term degradation is progressive, recoverable at major overhauls and again is in the order of 1- 2 %. Consequently, it is reasonable to assume that the average degradation over the lifetime of the plant will be 3-4 %. This implies that after two years the plant will operate 2.5 % below the Net Plant Heat Rate as tested in the EPC Performance Tests.

Other Heat Rate Losses

- Vacuum losses due to high ambient temperature, low cooling water flows, condenser tubes plugged and dirty, condenser excessive air ingress.
- Low Steam Conditions – HP/IP Pressures and Temperatures- (see coal quality above)
- Steam Turbine Efficiency- poor overhaul and maintenance record leading to dirty blades (possible due to poor water chemistry – condenser tube leakage) and excessive seal leakages.
- Feed Temperature Low – HP Heaters not available due to tube leakage
- Feed Water Make Up – due to maintenance activities and possible made worse owing to blowdown caused by condenser leakage

However, with low load factors, caused by availability and reliability problems heat rate would also be much higher than design owing to factors such as:

- Transformer losses;
- Works power in standby mode;
- Test running of equipment;
- Start up heat and electricity etc.

Plant Load Factor

An improvement of plant load factor (PLF) will in turn improved heat rates. With most states in shortage this has been achieved by higher availabilities, improved O&M, R&M etc.

Currently many plants/units have capped PLF caused by a failure to achieve rated output owing to poor coal and inadequate margins in fan throughputs and coal milling plant (standby) - see above

The decrease in PLF can reduce HR by 10-12 %, for a decrease in PLF from 80-50%.
In addition the increased PLF will reduce Auxiliary Power and also a likely fall in Secondary Fuel consumption.

Operation in excess of normative values

How do we judge the generators performance at stations operating above normative values and what/ how do we incentivise the Generators to improve.

Currently it appears that the Regulator is having a view on 'normative' values and where there are differences is asking the Generator to improve HR and achieve this value over a number of years – this is acceptable and fair as long as targets are achievable.

A major issue in this deviation is that the Capacity Charge is to remunerate the Generator for staff/payroll and the costs for materials and contractors, plus the generator should apply the correct O&M practices/skills/competences to achieve a reasonable level of technical performance.

Therefore if we assume a generator with above norm performance, who should pay for the improvements?

Assuming a Unit is operating above the norm, at say 2700 kcals/kWh. To reduce this over time could be achieved in a number of ways. There could be early /easy gains by improved O&M, this is clearly to be paid for out of O&M costs. However to achieve other gains may need additional plant modifications, overhauls etc and these would be established by rigorous cost /benefit analysis and may be allowed for in increased tariff by the Regulator or again be paid for from the existing capacity charge.

It should be noted that any further improvements will be either outside the control of the generator, or economically non-viable.

The following table sets out a potential framework for application.

Annex 6, Table 1 Works that can be carried out to improve efficiency at each level of heat rate performance

	1	**2**	**3**	**4**	**5**
Heat Rate	2500-2550 (kcals/kWh)	2550-2600(kcals/kWh)	2600-2650 (kcals/kWh)	2650-2700 (kcals/kWh)	>2700 (kcals/kWh)
Cost Category	Capital Investment to cover restabilising performance norms	Capital Investment or Normal O&M Expenditure –	Normal O&M Overhaul Expenses	Normal O&M Expenses and Practices	Normal O&M Expenses and Practices
Comment	Cost/Benefit Analysis to agree way forward	Cost/Benefit Analysis to agree way forward	Regulator expects Generator to improve O&M	Regulator expects Generator to improve O&M	Regulator expects Generator to improve O&M
Type of Work	Major Turbine Overhaul Feed Heater Renewal, Major	Condenser Tube Cleaning Equipment	Improvement in Milling Plant Maintenance	Reduction in Make Losses Improvement in Air Heater and Boiler Sealing	Reduction in Condenser Air Leakage

Milling Plant Replacement	Maintenance

Asset Management Plan

To assess the Generators Asset Management capability O&M Plans should be required that relate to performance and improvement plans for the site. They should be required to forward a detailed plan – similar to that required now but in more technical detail.

The Plan shall set out in sufficient detail the following information:-

- Vision - A short statement of the Generator's vision of the future.
- Operation Plan
- Key areas of operational performance, particularly
- Availability and Thermal Efficiency and initiatives in these and other operational areas which are necessary or desirable to maintain or improve performance.
- Maintenance Plan
- Maintenance proposals for the plan period.
- Investment Plan
- Description of all proposed capital investments and major repair or rehabilitation work accompanied by an outline investment appraisal including an analysis of risks, costs, benefits and economic return.

Heat Rate Reporting & potential enhancement

Unlike the very detailed reporting in CEA Databases for availability and capacity losses, there appears to be no similar standard of data in CEA Heat Rate reports, where the deviations from design or norms are explained or broken down into constituents and the reasons for these losses and what Generators are planning to do to manage them are explained.

In the following table we suggest the categories of reporting data that Generators should supply to the Regulator (and CEA if required) initially following an energy audit and then with such frequency as the regulator may determine.

Annex 6, Table 2 Proposed categories of reporting data that generators should supply to regulator

Item	Design Value/Target	Actual Value/Target	Comment
Fuel			
Fuel Quality			
Stock Deficit/Surplus			
Boiler			
Dry Flue Gas Loss			
Moisture Loss			
Carbon in FBA/PFA			
Radiation and Unaccounted			
Other key boiler operating parameters – Pressure, S/HT and R/HT Temperature (if applicable), S/T and R/HT Attemperator Flow etc			
Steam Water Cycle			
Condenser Loss			
Final Fed Temperature			
Make Up loss			
Turbine			
Cylinder Efficiencies			
HP			
IP			
LP			
etc			

Heat Rates – the Opportunity for Improvement

The drive to improve heat rate with its benefit to consumer in lower prices and environmental benefits (lower specific GHG emissions) are at the centre of this project.

So what kind of benefits could accrue if these incentives programmes actually deliver?

- ***Design Heat Rate***

The key driver for the normative approach is based on an assessment of how current plant performance compares with plant design.
EPC/OEM Contractors will have provided the Owners of a plant with a specific HR in the contract. This will generally be tested in accordance with various codes –

- Boiler -ASME PTC 4.1
- Turbine -IEC/953-1/2 and ASME PTC 6

The design will have been at certain reference conditions (e.g. ISO) and fuels. This could be different from the site conditions prevailing at specific plants. The contractor will also provide a range of correction curves to account for this. Therefore this has to be taken into account so see how this is expected to affect actual performance, taking into account factors such as age, ambient conditions and coal quality.

In addition this data will be for specific performance test with the plant 'new and clean' and burning the design reference coal. This issue causes particular problems when setting 'norms.'

CEA Data on Plant Performance

The table below shows data from CEA for the period 2000-2003. In general it shows that many Units are operating close to the normative target. Especially when operating at high PLFs.

Annex 6, Table 3 Data from CEA for period 2000-03

Plant size (MW)	Design HR (kcals/kWh)	Normative Target (kcals/kWh)	Average Actual (2000-2003) (kcals/kWh)	Average PLF (%)
500	2255	2450 (2410 with Steam Feed Pumps)	2410	81.91
KWU 200/210	2284	2500	2458	86.59
LMZ 200/210	2375	2500	2484	78.03

This must be seen in the light of reporting accuracy and stations do not always measure Unit Heat Rate with the require level of accuracy. However, it does show that in general many units are close to the normative targets and that overall perception of the data may be 'skewed' by a small number of very poor performing plants. .

Heat Rates – Deviation from Design

The following table shows the difference from design when taking a range of allowances for operational aspects and plant degradation. Again, it shows that in general plants are operating close to the normative target, when reasonable operational allowances are factored in. However, it also appears to validate the normative approach to setting a reasonable target.

Annex 6, Table 4

Plant size (MW)	**Design HR (kcals/kWh)**	**Operational HR with allowances +5%**	**Operational HR with allowances +7.5%**	**Normative Target (kcals/kWh)**
500	2255	2367	2424	2450 (2410 with Steam Feed Pumps)
KWU 200/210	2284	2398	2433	2500
LMZ 200/210	2375	2493	2553	2500

Heat Rate – Measurement Accuracy

The final table shows the actual performance levels with a range of measurement accuracies. Once more the performance is in line with the normative target.

Annex 6, Table 5

Plant (MW)	**Actual (2000-2003) (kcals/kWh)**	**Operational HR with tolerance for allowances for accuracy +1.5%**	**Operational HR with allowances for accuracy +2.5%**	**Normative Target (kcals/kWh)**
500	2410	2446	2470	2450 (2410 with Steam Feed Pumps)
KWU 200/210	2458	2495	2519	2500
LMZ 200/210	2484	2522	2546	2500

ANNEX 7 - CONTRACTING OUT R&M WORK

Potential power plant contractors

Discussions are ongoing in the industry in India in relation to the potential for an R&M Contractor to operate and maintain the plant after modification - this could take various forms –

- Full O&M Contract
- O&M Management Agreement
- Long Term Support Agreement (LTSA)

These all vary in a number of ways and are Project Specific. The variance is mainly in the scope of plant covered, provision and payment of spares and resources (staff) to carry out inspections. It will also take into account the operating regime of the plant.

- Can be linked with the R&M Contract (often best value when captured in the bid – OEM uses them to protect warranty claims)
- Availability and HR Guarantees
- Boundaries need to be defined
- Technical Support
- Spares Provision and Refurbishment
- Maintenance Resources –OEM and/or O&M, Planned and Emergency
- Various Term of contract

O&M Contract Guarantees and Performance Incentives

The Generators would prefer to have some form of Performance Guarantees and Incentive system in place in the form of a Bonus/Liquidated Damages mechanism following R&M programmes. There has been much discussion, not only in India but in other countries in the use of guarantees to be provided by EPC and Plant R&M Contractors. In general these are hard to come by at a reasonable cost, the contractor will in general factor/price of this in his tender.

With R&M contracts there are numerous difficulties in detailing the scope of work and deciding on the performance factors etc. It is usual for contracts to stipulate the maximum liability that will be paid. This is often limited to the annual fees of the Contractor (NTPC have confirmed this would apply to their third party O&M support agreements). Similarly it is normal for the Bonus to also have a maximum limit.

A number of considerations will need to be made in determining the most appropriate payment structure. These include:

- The extent to which objective assessment of contract performance is possible
- The ease with which realistic targets can be set for contractor performance
- The administrative effort involved with each payment option

- The degree of certainty with which the desired contract outcomes can be specified

Especially with R&M projects and with new contractual arrangements being put in place many contractors would not enter into some of these arrangements as they have less control especially over issues relating to:

- maintenance costs are not mature
- design and quality affecting performance
- historical operational issues
- historical maintenance issues
- fuel quality and availability

Therefore often methods are put in place for transitional arrangements to gradually transfer the guarantee structure from one method to another over time, as a greater degree of certainty over the requirements of the contract, and more accurate knowledge of target levels of performance is established.

Typical Guarantees and Performance incentives for an OMCO should be based on:

- Capacity
- Availability
- Efficiency
- Budgets
- Health, Safety and Environmental

Scope of O&M or LTSA Services

As can be seen below the scope of O&M Contract or LTSA can vary with various options available to the Generator in regard to individual responsibilities say in respect of the Coal and Ash Handling Plants – see below

Annex 7, Table 1

Activity	Responsibility Option 1	Responsibility Option 2	Responsibility Option 3
Technical Support - Staff Bulletins etc	Contractor	Contractor	Contractor
Remote Monitoring	Contractor	Contractor	Contractor
Emergency Response	Contractor	Contractor	Contractor
Spares Ordering	Contractor	Contractor	Owner
Spares Purchase	Contractor	Owner	Owner
Spares Management	Contractor	Contractor	Owner
Outage Planning	Contractor	Contractor	Owner
Outage Technical Support and Supervision	Contractor	Contractor	Contractor

Outage Resources (arranged and paid for)	Contractor	Owner	Owner
Performance Guarantee	Contractor	Contractor	Contractor

List of potential contractors for EE R&M works in India.

- Bharat Heavy Electricals Limited
- Crompton Greaves Ltd.
- National Thermal Power Corporation Ltd.
- Siemens
- Larsen & Toubro
- Hindustan Construction Company Ltd.
- Uhde India Limited
- Gammon India
- Toyo Engineering India Ltd
- Tata Projects
- Aker Kvaerner India
- ABB
- Alsthom

ANNEX 8 – REPORT ON INTERNATIONAL COMPARATORS

Introduction

This Annex sets out our review of international comparators in relation to the incentivisation of energy efficient rehabilitation and maintenance of coal fired power stations, as follows: .

- a brief review of the key issues in India and an assessment of those countries that might provide the best international comparators for India, or, at least, even if there are few directly relevant comparators, asks what might be the most interesting lessons from international regulatory practice; and.
- a more detailed review of the regulatory frameworks in our 4 chosen comparator countries, focussing on:
  - the industry structure and energy policy framework;
  - where these are relevant or interesting, the general use and nature of regulatory incentives, including the use of normative or benchmarking measures for operational costs, output incentives and any other relevant schemes;
  - the specific schemes and incentives designed to support energy efficient rehabilitation of power stations (if any);
  - the use of subsidies to support capital investment or otherwise reduce the output costs of generating plant;
  - the market framework, and
  - energy purchasing and wholesale pricing frameworks and any related regulatory controls, including approaches for dealing with the costs of energy shortages and for incentivising the construction of sufficient reserve capacity.
- a summary of the various control and incentive based schemes we have identified.
- our conclusions in relation to the lessons for the rehabilitation and modernisation of (old) coal fired plant in India.

Because most international experience in relation to the generation policy objectives relates to renewables generation rather than the rehabilitation and modernisation of coal fired generating capacity, we have also included a brief review of policy tools and instruments and market frameworks applying in four more Western European and North American markets.

Key issues for India

The present national electricity policy in India provides that the availability, reliability and quality of power supply "to Indian industry" are key goals (equal to the provision of supply to rural customers). In relation to generation, against a background of rapidly increasing demand, the policy sets out the following key objectives:

- to add 100,000MW of new capacity in the period 2002-12;
- to enhance the availability of installed capacity to 85%; and
- to create a spinning reserve margin of 5%.

In relation to thermal generating capacity the policy notes that coal fired power stations will continue to make a significant contribution to India's power supply and will "necessarily remain the primary fuel."

In relation to renovation and modernization specifically the policy states that:

- "renovation and modernization for achieving higher efficiency levels needs to be pursued vigorously and all existing generation capacity should be brought to minimum acceptable standards. The Govt. of India is providing financial support for this purpose;"
- "all efforts will have to be made to improve the efficiency of operations in all the segments of the industry. Suitable performance norms of operations together with incentives and disincentives will need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. This will ensure protection of consumers' interests on the one hand and provide motivation for improving the efficiency of operations on the other;" and
- "it is competition which will determine the price rather than any cost plus exercise on the basis of operating norms and parameters. All efforts will need to be made to bring the power industry to this situation as early as possible."

In relation to the need for co-ordinated development the policy notes that:

- "State Governments need to ensure the success of reforms and restoration of financial health in distribution, which alone can enable the creation of requisite generation capacity."

Our review of the present framework for EE R&M projects in India, as described in Annex 4, suggests that there are a number of barriers and constraints operating within the present regime. In brief these can be summarised as follows:

- Energy policy – general energy policy statements and tools (such as the ability to direct an energy audit) are perhaps not adequately reflected in the regulatory framework;
- Financial health – the state sector is suffering from poor financial health and exposure to expensive imported power, with the costs of replacement power during necessary outages for EE R&M projects causing severe financial problems for distributors;
- Managerial and technical capacity – there is generally considered to be a lack of managerial and technical capacity, although measures are undoubtedly being taken to improve this situation and there is, potentially, a lack of engineering resource to actually undertake EE R&M projects;

- Establishing the baseline – there is a lack of trust in the regulatory framework that appears to derive from an information asymmetry problem, with a particular lack of clarity in relation to the baseline position. This reflects a limited use of energy audits and problems in relation to the establishment of precise fuel quality measures;
- Regulatory certainty and transparency – in some cases there is a lack of clarity in relation to the operation of incentive mechanisms, in particular in relation to the so-called "periodicity" problem, the period over which the generators will retain the benefit of any outperformance against regulatory targets.

In addition, we might add that, related to the question of financial health, there is the question of a potential misalignment of risks and benefits, with generators unwilling to take the risk of investing in measures to secure outperformance when they fear that most/all of the benefits will flow to the Discoms (and with the Discoms unwilling to sanction EE R&M schemes because of the adverse short term impacts on their financial health).

Comparator requirements

Our research for this report suggests strongly that there is very limited direct international experience of the incentivisation, through tariff based mechanisms, subject to regulatory control, of the energy efficient rehabilitation and modernisation of coal fired power stations.

We believe that this results from a number of factors, including the following:

- in many countries, including Western Europe, North America, Australia and most of South America, generator prices are not subject to direct regulatory controls, but are limited by the operation of a competitive wholesale market;
- in most of Western Europe and to a lesser extent in Australia and North America, national or state level energy policies mean that national and/or state Government subsidies are directed towards "renewable" sources of power or to new and much more advanced "clean coal" technologies, rather than to the achievement of more limited efficiency gains derived essentially from the enhanced use of existing technologies, at existing coal fired plant;
- in most of Western Europe and to a lesser extent in Australia and North America, national or state level energy policies and/or emissions targets (in many cases derived from the Kyoto Treaty) effectively place constraints on the output of coal fired generating plant, either on a plant specific basis or on the basis of the generator's plant portfolio;
- energy policies and emissions limits mean that, where direct subsidies are not given, some form of prioritisation is normally given to power generated from renewable sources, either as a form of wholesale market based discrimination (such as a merit order preference) or as a form of supply (retail) market based discrimination (such as a transmission company or supplier/distributor obligation to buy output);
- in most instances it must be said that these markets are not characterised by strong concerns in relation to the customer's ability to pay for electricity or by strong concerns in relation to the adequacy and reliability of supply (which are of course related) although this is not to say that such concerns

are altogether irrelevant, just that they exert comparatively little influence on policy and decision makers;

- in many cases suppliers/retailers will contract with generators for a given volume of power, on the basis of a firm delivery obligation, normally leaving the generator to source replacement power in the event of an outage, rather than the supplier/distributor.

However, most countries do operate regulatory frameworks that involve the use of incentive mechanisms and we have therefore set out in this Annex a brief review of the operation of these mechanisms, whilst also setting out the broader background in relation to generation policy objectives and the use of fiscal and other incentives for generation policy objectives.

To the extent that such matters are transparent, our review of the operation of incentive mechanisms within the regulatory framework for the four countries identified in our proposal concentrates on 4 key indicators of clarity in the regulatory incentive framework, as follows:

- the relationship of the incentive mechanisms to the energy policy framework and broad regulatory objectives and the definition of the performance to incentivise;
- the establishment of a baseline from which to measure performance enhancements and to set revised performance targets;
- the calculation of the appropriate level of the performance incentive; and
- the measurement of improvements achieved or claimed.

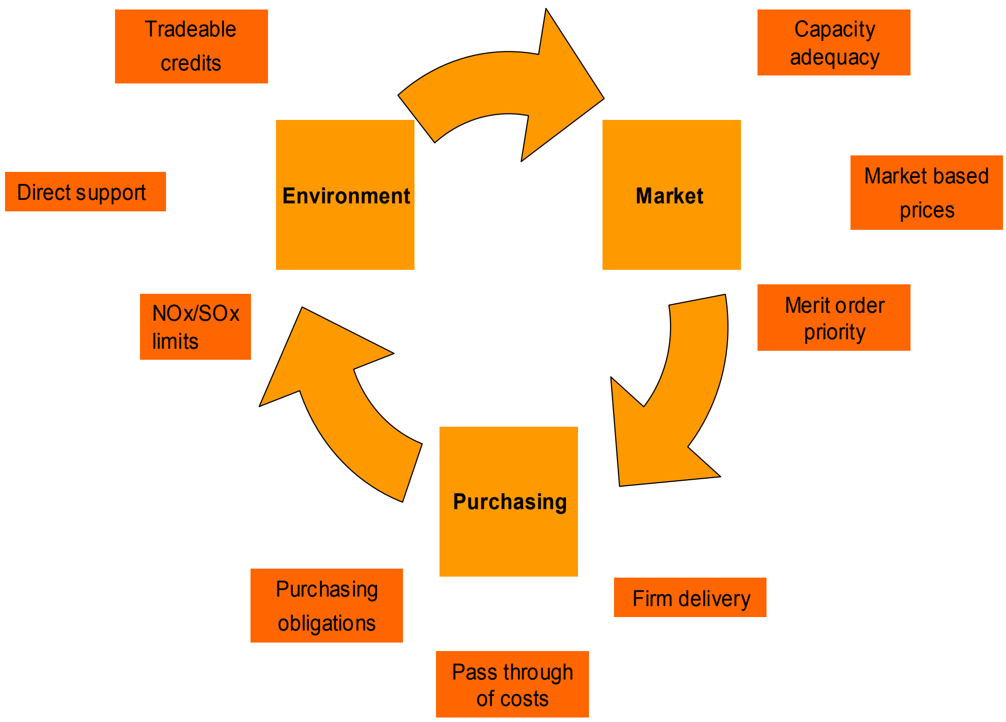
In addition, for each of our identified comparator countries we have also briefly reviewed the following:

- the energy policy framework and incentives relating to environmental rather than economic objectives (which may nevertheless be achieved through economic instruments) including direct grants, NOx/SOx and other emissions controls and targets and tradeable credits;
- the market framework, covering merit order or despatch arrangements (indicating any priority given for certain plant);
- the energy purchasing framework and any related regulatory controls, such as obligations to purchase power from specified sources or controls on effective/economic purchasing; and
- capacity adequacy/reserve capacity incentives.

As indicated in our proposal and taking into account the above factors, we have focussed our review of international best practice in relation to regulatory incentives, the energy policy framework, generation incentives and the operation of the wholesale market on four key markets; Australia, the UK, the USA; and South Africa; each of which illustrates a different approach and a different energy policy framework.

However, as suggested above, we have also added an overall review of the wholesale market, energy purchasing and environmental framework applicable to specific generation incentives (for renewable technologies) for four additional countries, Italy, the Netherlands, Germany and Alberta in Canada.

Annex 8, Figure 1 – wholesale market, purchasing and environmental framework for comparator countries



Australia

Industry structure and broad policy framework

The Australian coal industry is one of the world's largest and Australia is at present the world's largest coal exporter. For energy policy and commercial reasons Australia is keen to incentivise and develop new, more efficient coal burning technologies and technologies that bury CO2 underground (carbon capture or sequestration).

The other major energy policy initiative of recent years concerns energy market reform. On 11 December 2003, the Ministerial Council on Energy (MCE) released a communiqué and an accompanying document entitled "Reform of Energy Markets". The overall thrust of this initiative was to create electricity and natural gas markets that have true national scope, rather than being state-based.

The primary institutional change in this reform is the creation of two new bodies at the Federal level; the Australian Energy Market Commission (AEMC), responsible for rule-making and market development, and the Australian Energy Regulator (AER), responsible for energy regulation. The motivation behind the creation of these two entities is to separate the rule-making function from the implementation of the rules.

The electricity industry dominates coal use in Australia. Of the 48.0 Mtoe of coal used in Australia in 2003, only 2.7 Mtoe, or 5.6%, was used in direct applications as a final energy product. The remainder was used in coal-fired electricity generating plants, which accounted for 77.2% of total electricity generation in Australia. Coal's share of electricity generation has been above 70% at least since 1973 and it is expected to continue as the dominant source, accounting for 71.1% of total generation in 2020. In 2004, there were 28,350 MW of coal-fired capacity, with an average efficiency of 33%.

Brown coal production in 2003 accounted for only 8% of total production on an energy content basis. Brown coal is found primarily in the state of Victoria, although other known resources are found in Western Australia, South Australia and Tasmania. Australian brown coal is used almost exclusively at mine-mouth electricity generating stations in Victoria. All brown coal mines are owned jointly with the related power generation facilities and all are privately-owned. At current mining rates, the brown coal reserves are expected to last for several hundred years.

The Australian black coal industry is located almost entirely in the states of NSW and Queensland. At current rates of production, these resources would last approximately 220 years. However, capacity expansions are planned for coal mining. As of early 2005, 17 new black coal projects were under consideration with a combined capacity of 86.5 Mt, or about 20% of current production.

Without development of a suitable technology to curb the high emissions from coal combustion, Australia would only be able to embrace serious climate change plans with substantial economic costs, not only because of the widespread use of coal domestically, but also because of more stringent GHG targets in coal-importing countries, which would affect the future of Australia's most valuable export product.

At the time of writing it remains to be seen precisely how the recent Australian election results will impact on the country's coal generation capacity, but with Australia now likely to reverse its previous opposition to the Kyoto Treaty there would appear to be a strong likelihood of additional policy, regulatory and financial incentives to cleaner and more efficient generation technologies. Whether these will build on the success of the Macquarie Generation project financed under the old Greenhouse Gas Abatement Programme (summarised later) remains to be seen.

The main incentive mechanism in use in the energy industry in Australia relates to the operating efficiency of gas and electricity transmission and distribution networks. This copies many elements from the incentive schemes originally developed in the UK during the late 1980s, although Australia has learned from some of the defects of the UK scheme and modified it in some respects.

Establishment of a performance baseline

The performance baseline for the operation of the transmission and distribution network incentive scheme in Australia is established using the following sources of data:

- monitoring of audited regulatory accounts;
- completion of detailed questionnaires on past and forecast operating and capital costs;
- the results of benchmarking with other companies; and
- consultancy reviews of projected efficiency gains, based on best practice operating techniques.

In relation to benchmarking the Australian Competition and Consumer Commission (the overall economic regulator) has stressed the importance of benchmarking as a decision support tool, rather than a replacement for regulatory judgment and has indicated that the primary need in Australia is a focus on improving the quality of data collection processes, auditing, and standardisation.

Setting the appropriate performance incentive

In a recent policy document the newly established Australian Energy Regulator (AER) set out its view of the operation of incentive mechanisms for transmission network service providers (TNSPs), as follows "the length of the carryover period directly affects the desired sharing ratio of gains and losses between users and the TNSP. This gain is normally measured as the net present value of a gain or loss in a particular year, relative to the value of that gain or loss in perpetuity. A five-year carryover period results in a benefit sharing ratio of approximately 30:70 between the TNSP and network users. A ten-year carryover results in a ratio of approximately 50:50 for the TNSP and users respectively."

The AER considers that this …"will be simpler to implement if the carryover period is linked to the regulatory control period for a business. For most businesses, this will mean a notional five-year period for the carryover and an effective 30:70 sharing ratio. Where a firm has proposed a longer regulatory control period, the AER will consider extending the carryover period, having regard to the need for a fair sharing of efficiency gains and evidence of the relative efficiency of that firm."

In order to overcome the problem that incentives are greater at the start of a price control period and will be quickly return to customers if made at the end of a price control period the AER has developed a "Continuous efficiency incentive." Under this scheme a continuous incentive to achieve efficiencies is provided by allowing the TNSP to retain, for a fixed period, the difference (negative or positive) between its actual and forecast operating expenditure (opex). Any such difference arising in **any** year of a regulatory period is retained by the TNSP and carried forward for five years following the year in which the efficiency gain or loss is incurred. In this way, the scheme encourages firms to remain efficient throughout the price control period.

The AER states that, for firms operating at or near to the efficiency frontier it will consider extending the carryover period in order to provide a greater incentive, subject to its being provided with evidence in relation to the firm's efficiency.

The AER's calculation of benefit sharing for different price control periods is set out in Table 1of this Annex. Table 2 of this Annex sets out current practice in the Australian gas industry.

Annex 8, Table 1 – sharing of incentivised efficiency

Period of benefit retention (years)	Regulated company benefit	Customer benefit
3	**20.9%**	**79.1%**
4	**25.4%**	**74.6%**
5	**29.7%**	**70.3%**
6	**33.8%**	**66.2%**
7	**37.6%**	**62.4%**
8	**41.3%**	**58.7%**
9	**44.7%**	**55.3%**
10	**48.0%**	**52.0%**
11	**51.1%**	**48.9%**

Note: sharing ratios have been calculated assuming a 5.66 per cent real discount rate.

Annex 8, Table 2 – sharing of incentivised efficiency gains in Australian gas industry

Regulator	Forecast efficiency gains	Additional efficiency gains
Commonwealth	Not retained	Retain 5 years
Victoria	Not retained	Retain 5 years
New South Wales	Not retained	Retain until reset
South Australia	Not retained	Retain 10 years
Western Australia	Not retained	Retain until reset
Queensland	Not retained	Retain until reset

Source – Australian Gas Association

The AER has also ruled that, because it would be rare for a firm operating in a competitive market to retain efficiency gains for a period of more than five years, a 10 year carry forward/retention period, with a 70/30 gain in favour of companies would be too long and that 5 years should be the norm.

Measurement of improvements achieved

In order to close the loop on the incentive scheme the Australian regulator uses the following techniques to monitor the results of his incentive scheme:

- audited regulatory accounts;
- detailed quality of service performance reporting; and
- comparisons with other companies.

Controls and incentives for generation

The Australian Federal Government has created a Low Emissions Technology Demonstration Fund, with around A$500m available to help finance projects that would reduce greenhouse gas emissions and one of the key projects supported by this fund is the so-called “Oxygen” project, which plans to alter the way in which coal is burned to enable CO2 to be more easily separated and then stored, so reducing the negative impacts on efficiency of other CO” capture technologies.

In addition, BP and Rio Tinto (Anglo-Australian mining company) have announced plans to build a A$2bn coal fired plant in Western Australia that would bury most of its CO2 in an offshore underground reservoir, whilst Stanwell Corporation (owned by the State Government of Queensland) has announced similar plans in relation to the ZeroGen project to be located within the state. ZeroGen has applied for support from the Federal Governments Low Emissions Technology Demonstration Fund.

A summary of each of the incentives and controls applicable at the present time is set out below.

- ***The National Greenhouse and Energy Reporting Act 2007***

  The National Greenhouse and Energy Reporting Act 2007 established a single, national system for reporting greenhouse gas emissions, abatement actions, and energy consumption and production by companies, commencing on 1 July 2008.

  Data reported through the system will underpin the Australian Emissions Trading Scheme. The ability to monitor, report and verify businesses' emissions data will be essential for maintaining the environmental and financial integrity of the trading system.

  Key features of the system are:

  - a single online entry point for reporting based on the Online System for Comprehensive Activity Reporting (OSCAR);
  - a standard data set and nationally consistent methodologies for reporting;
  - public disclosure of company level greenhouse gas emissions and energy data;
  - consistent and comparable data provided to government for policy making;
  - secure data storage; and
  - reporting thresholds that avoid onerous regulation for small business.

- ***Generator Efficiency Standards***

On 1 July 2000, Australia introduced a voluntary measure for fossil fuel electricity generators to reduce the greenhouse intensity of energy supply. The Generator Efficiency Standards apply to new projects and existing electricity generators above a minimum threshold, whether grid-connected, off-grid or self-generators.

The minimum threshold is 30 MW capacity, 50 GWh electrical output, and capacity factor of 5% or more in each of the last three years. The current (2004) best-practice efficiency guidelines for new plants are:

- Natural gas plant, 52% net thermal efficiency (Higher Heating Value HHV);
- Black coal plant, 42% net thermal efficiency (HHV) and,
- Brown coal plan, 31% net thermal efficiency (HHV).

The measure is implemented through legally-binding, 5-year Deeds of Agreement between the Australian Government and participating businesses. Following implementation of action plans, generators are required to monitor their performance and report to the AGO (Australian Greenhouse Office) on an annual basis. The efficiency targets set under the scheme are expected to be reviewed every 5 years.

The scheme is focussed on greenhouse gas emissions, rather than analysing any economic benefits from enhanced generation efficiency. Nevertheless, the methodology and process used may provide useful models for India.

Of particular importance in our view is the emphasis laid on accurate and verifiable measurement of efficiency enhancements and claimed greenhouse gas emissions reductions.

A copy of the reporting guidelines for the operation of the scheme and the performance reporting arrangements can be found at the following link:

http://www.environment.gov.au/settlements/ges/publications/pubs/program_guidelines.pdf

A copy of the technical guidelines, including the details of a whole series of relevant Australian technical standards and codes that may provide a useful model for the application of common standards in India, in particular in relation to:

- coal weighing;
- coal sampling;
- coal analysis;
- plant testing;
- the calculation of thermal efficiency;
- plant degradation;
- typical efficiency gains from specific improvement projects.

The guidelines can be found at the following link:

http://www.environment.gov.au/settlements/ges/publications/pubs/technical.pdf

- ***Funding for Low Emissions Technology and Abatement***

  In 2005, the Australian Government announced that it would provide funding of $26.9 million over four years (2005-2009) to encourage ongoing investment in the development, demonstration and deployment of smaller-scale low emissions technologies, and other cost-effective abatement activities through the Australian Greenhouse Office and the Department of Environment and Water Resources.

  Projects eligible for funding should fall into one or more of the following categories:

  - Low Emissions Fossil Fuel Technology
  - Strategic Abatement
  - Geosequestration
  - Renewable Energy.

- ***Low Emissions Technology Demonstration Fund***

  The Low Emissions Technology Demonstration Fund supports industry-led projects to demonstrate low-emission technologies. These technologies must have the potential to lower Australia's emissions by at least 2% in the long term at realistic uptake rates and be commercially available by 2020 to 2030.

  The fund is designed to facilitate private sector investment of at least $1 billion and provides a path by which industry can invest in a low-emissions future. It is aimed at supporting technologies at the commercial and demonstration stage, when required investments are large and risks remain high.

  In 2006, the Australian Government committed $AUS 60 million to develop the world's then largest carbon capture and storage (CCS) project in Western Australia.

- ***Greenhouse Gas Abatement Program (GGAP)***

  The Australian Government's Greenhouse Gas Abatement Programme (GGAP) has played an important part in helping Australia meet its international emissions reduction target.

  GGAP aims to reduce Australia's net greenhouse gas emissions by supporting activities that are likely to result in substantial emissions reductions or activities to offset greenhouse emissions, particularly in the period 2008-2012. The most recent emission projections show that GGAP will deliver an abatement of 5 million tonnes (Mt) of carbon dioxide equivalent (CO_2-e) in 2010.

  The programme leverages private sector investment in activities or technologies through projects. Examples of GGAP projects are based on co-generation (the use of waste heat or steam from power production or industrial processes for power generation), energy efficiency, travel demand management, alternative fuels, coal mine gas technologies and fuel conversion.

Three funding rounds of GGAP have been concluded (industrial processing/ mining, power generation and travel behaviour change) but no subsequent rounds are being offered and the residual funds earmarked for GGAP have been dispersed to a range of other programmes.

One project of particular relevance to this project was equipment upgrade to enhance the efficiency of the Liddell Power Station in New South Wales. Project details are set out below.

In a further energy efficiency project, the GGAP provided AUS$11m of an AUS$175.7m total investment to fund the replacement of 30 year old rotary kilns used by Queensland Alumina Limited (QAL), which operates the world's largest alumina. Unfortunately for this project the commercial details of the project are not publicly available, reflecting the GGAPs concern to protect the commercial confidentiality of investors.

Example - Macquarie Generation – Liddell Power Station, NSW

The Macquarie Generation project was designed to increase the generating efficiency at the Liddell Power Station located near Muswellbrook in New South Wales.

Prior to the project, the efficiency of the Liddell Power Station turbines was around 85 per cent. Through the replacement of the old low pressure turbines with modern turbines, the GGAP project increased the generation efficiency of the four 500MW units by an average of 3.32% across the four units.

Hitachi Australia Ltd was contracted by Macquarie Generation to design, manufacture, install and commission the new Low Pressure turbines at Liddell Power Station and the upgrade was successfully completed in July 2005.

GGAP funding: $5 million
Total project cost: Over $53 million.

Outcome:
Expected greenhouse gas abatement:
Total abatement up to 1.66 million tonnes of carbon dioxide equivalent is expected in the Kyoto commitment period 2008-2012.
Efficiency improvements:
More energy can now be extracted from the steam flowing through the turbine, allowing an increase of more than 60MW in the output capacity of Liddell, with no increase in CO_2 emissions and reduced sulphur dioxide and nitrous oxide emissions from burning less coal. There are also lower water demands from the power station and reduced sulphur dioxide and nitrous oxide emissions from burning less coal. As a result the project is a potential catalyst for investment in similar large scale abatement projects by other coal fired generators.
IPA note – as far as we can determine, no further funding has yet been agreed for similar projects and the GGAP programme has been ended.

Technical summary:
The efficiency increase is achieved through improved control of the flow of steam through the turbine. Advances in computer modelling techniques allow for more detailed assessment of the impact of various steam path design options. This results in closer to optimum conditions than was achievable when the Liddell turbines were originally designed.

Public Dissemination Report:
The full public dissemination report for the project can be found at www.greenhouse.gov.au/ggap/pubs/macgen-pdr.pdf

- ***COAL21 Programme***

The COAL21 programme is a collaborative partnership between Federal and State Governments, the coal and electricity generation industries and the research community. The key objectives of COAL21 are to:

- Create a national plan to scope, develop, demonstrate and implement near zero emissions coal-based electricity generation ;
- Use the plan to inform Governments and industry as an input to policy development;
- Facilitate the demonstration, commercialisation and early uptake of technologies identified in the plan;
- Promote relevant Australian R&D;
- Foster greater public awareness of the role of coal and the potential for near zero emissions coal-based electricity generation to reduce or eliminate greenhouse gas emissions and other environmental impacts associated with its use;
- Provide a mechanism for effective interaction and integration with other international zero-emission coal initiatives.

Market Framework

- ***National Electricity Market***

Australia was one of the first countries to undertake substantial market reform in the electricity sector. Limited wholesale market trading began between New South Wales (NSW) and Victoria as early as 1994. The National Electricity Market (NEM) commenced operation in 1998 as part of the process of deregulation of the Australian electricity supply industry (ESI) and involved the separation of the previously vertically integrated supply chain of generation, transmission, distribution and supply.

The NEM is the wholesale market for the supply and purchase of electricity combined with an open access regime for use of the transmission and distribution networks. Legally, the NEM was established under state legislation. This reflects the nature of the Australian Constitution, which does not assign responsibility for energy matters to the Federal Government. The powers of the Australian Government in this area are indirect, through responsibility for such things as trade and commerce and corporations.

The NEM is structured around a common pool, or spot market, for trading wholesale electricity. All electricity generated by licensed market participants with a minimum of 30 MW of capacity must be traded through the pool. A single central dispatch process determines the merit order for the dispatch of generation (with the lowest-priced generator dispatched first subject to system and other operating constraints) based on a five-minute dispatch cycle and 30-minute trading intervals. Electricity is valued at one price (i.e. no separate provision for capacity payments) with a spot price cap of AUD 10 000 per MWh.

Retail market opening, or full retail contestability (FRC) as it is termed in Australia, was introduced from 1 January 2002 in NSW, 13 January 2002 in Victoria, 1 January 2003 in SA and 1 July 2003 in the ACT. FRC gives all electricity customers the right to choose their retail supplier for electricity according to their individual needs. Even where FRC is available, customers can opt not to enter a contestable market and can remain under what is called the “franchised load” or “standing offer” arrangement at fully regulated electricity tariffs.

In Queensland, retail contestability was granted from 1 July 2004 to connection points consuming more than 100 MWh per year. The Queensland Government has decided not to introduce FRC at this stage.

The Snowy Mountains Hydro Electric Scheme operates as an independent entity in the NEM with 2 256 MW of hydropower. While this is part of a separate region in the NEM, it is connected to both NSW and Victoria allowing trade between regions that is critical to the smooth operation of the NEM. As a peaking plant, with generation limited by the available water supply, Snowy Hydro also aims to compete in the higher-priced peak periods of the NEM trading day to maximise its return.

Information on electricity sector regulation in other states and territories that are not a part of the NEM is included below.

- ***Western Australia***

  The Western Australian (WA) electricity industry is characterised by a small and geographically diverse load with minimal grid development beyond the south-west and a large number of isolated power plants. Retail contestability has existed to a limited degree since 1997. Since then, more tranches have been opened up increasingly allowing consumers to choose their electricity supplier. A wholesale electricity market will be in place for WA by July 2006, which will have key elements such as bilateral contracts, a residual trading market and balancing mechanisms. These arrangements are intended to encourage competition in the WA market.

- ***Northern Territory***

  In the Northern Territory (NT), the ESI is characterised by a small and geographically dispersed load with minimal grid development. Electricity is supplied primarily by Power and Water, a state-owned corporation, but private ownership of generation and distribution facilities is permitted. On 1 April 2000, the NT introduced retail contestability for customers with an annual consumption of at least 4 GWh and on 1 April 2002, customers with annual loads greater than 750 MWh became contestable. The NT government has decided to defer the remaining contestability tranches for up to five years.

Purchasing & Pricing

The main wholesale market in Australia, the NEM, is a market based pooling system, with prices bid by generators and despatch n the basis of the most cost efficient stack of generator bids needed to satisfy demand. As such generator prices are set by competition rather than regulation and a generator's decision to undertaken rehabilitation and modernisation would therefore reflect his forward projections of revenue available from the market and his expectation of despatch based on estimated future running costs.

Wholesale electricity prices in Australia appear to be substantially below those in other countries that have developed liberalised markets with accompanying power pools, but it should be noted the pool is a single price mechanism without a separate capacity price. .

Based on an analysis of pool prices over 2003 and 2004, the average Australian pool price was 44% below Nordpool, 37% below Germany and 46% below the pool price in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) in the eastern United States.

While the figures are indicative of significant price differences between regions, care should be taken in using them for a full assessment of the efficiency of the different electricity systems. Pool prices can be affected by:

- the different stages of the investment cycle;
- overcapacity remaining from regulated regimes, especially in a recently interconnected market;
- unusual meteorological conditions over the comparison time period (e.g. rainfall, temperature);
- different input fuel costs and general availability; and
- the use of average exchange rates by year rather than month..

Whilst prices are low by international terms, there was a general upward trend in Australian pool prices from 2003 to 2004 and year on year, pool prices rose approximately by 50%. This was due in part to a general tightening of the supply-demand balance and the lack of new generation investment in 2004 (partly as a result of anticipating the low priced Tasmanian imports that will likely result from the completion of Basslink).

Despite this it is generally accepted that prices at the 2004 levels do not yet justify the construction of a major baseload plant, such as a coal-fired plant. However, prices are close to the necessary level for such a new plant and are expected to rise further as demand continues to rise and the excess capacity margin reduces.

- ***Electricity Tariff Equalisation Fund (ETEF)***

  On 1 January 2001, the NSW Government instituted the Electricity Tariff Equalisation Fund (ETEF). Under ETEF, standard retail suppliers in the state are required to pay money into a fund when the NSW pool price is below the regulated energy component (REC) that is allowed to be recovered through regulated tariffs and receive money from this fund when the pool price is above the REC. ETEF operates as a financial hedge for retailers, or what is termed a contract for difference (CFD) in the Australian market.

With this protection, they are free to earn what is essentially a guaranteed margin on the volume of their sales. Generators still receive the prices determined by the pool. However, if the fund develops a negative balance as a result of pool prices being substantially above the REC for a sufficient time, the state-owned generators are required to contribute funds needed to keep the fund solvent. ETEF would then repay generator contributions over time as pool prices rise and the fund balance recovers.

Whilst this is an interesting development it is not clear that it provides suppliers with the necessary signals to compete with each other by purchasing power more effectively than their competitors. In turn therefore it would fail to put significant pressure on generators to reduce their bid prices, or to offer suppliers attractive "contracts for differences" and it may be felt to distort the market.

- ***Reserve capacity***

In the Australian NEM the National Electricity Market Management Company (NEMMCO) is responsible for securing the capacity necessary to ensure an adequate system capacity margin or system reserve. It effectively acts as a form of "reserve trader," procuring the necessary capacity in the market, both from providers of demand response services (which provided approximately 25% of the last contract placed and which therefore provide a truly accurate picture of the value to consumers of unmet demand/lost load) and from traditional generating plant.

The costs of procuring the necessary reserve capacity for the system are spread amongst system users (socialised). There are concerns from generators both about the costs of the reserve trader function (especially in relation to its inclination and incentive to act conservatively) and about the potential impact of this scheme on signals for future generation investment (which are said to be dampened).

Great Britain

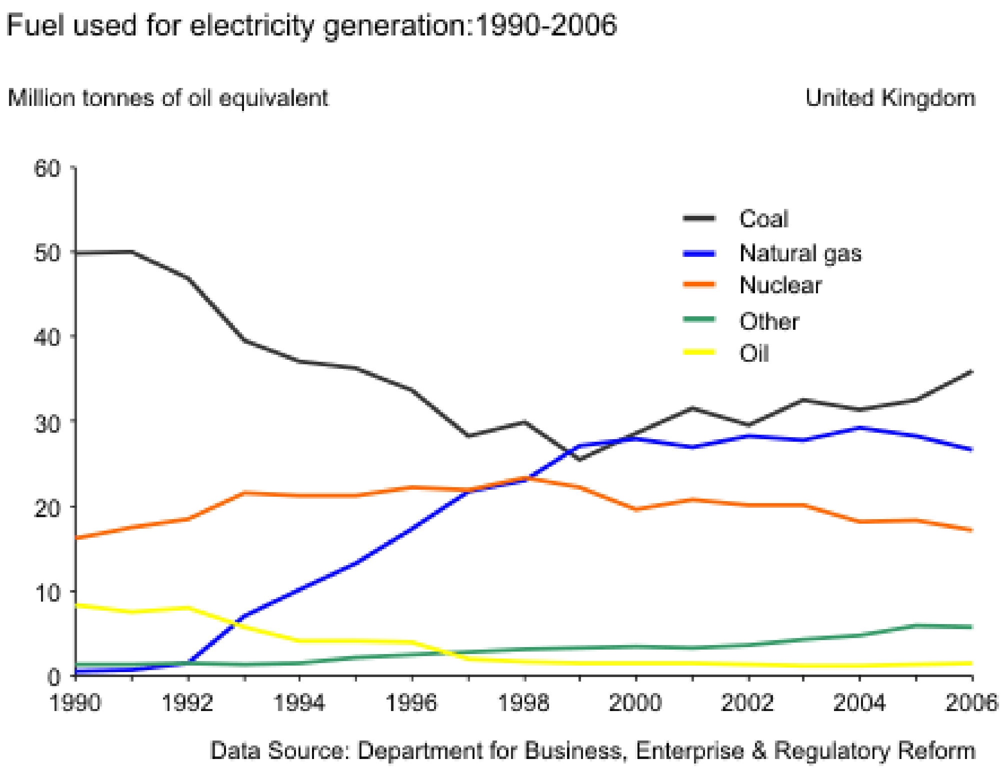
Industry structure and broad policy framework

Coal fired generation in Great Britain has been dwindling for many years, from a position of around 75% in 1990 it now accounts for only around 35% of total generation output, a slightly higher figure than for gas, with nuclear the third main fuel used.

As can be seen from Figure 2 of this Annex, the position has stabilised in the last few years, especially because of the introduction of flue gas desulphurisation (fgd) equipment which effectively permits coal fired plant to run for longer hours within the allowed emissions limits and through the importation of cheaper and low sulphur coal. Imported coal costs around £25 per tonne, compared with £40 a tonne for British coal and around 70% of coal used in Britain is now imported.

However, even though there are some hopes for clean coal technologies, eventually, the downward trend in coal fired generation is expected to continue, mainly as a result of ever tightening environmental constraints and an ageing plant portfolio and this will be exacerbated if the UK decides to opt for a new generation of nuclear power plant. The UK Government has recently announced its support for a new generation of nuclear plant in order to ensure diverse and reliable electricity supplies, though these power stations are expected to be built with private finance and without financial support from Government.

Annex 8, Figure 2 – the UK fuel mix for generation



The UK Government's energy policy was published in a "White Paper" entitled "Our Energy Future – creating a low carbon economy." The White Paper clearly

sets out the Government's intent to deliver its policy objectives through competitive, market based outcomes, wherever possible.
The UK Government's energy policy is that competitive generation and retail supply markets will provide the best prices and optimum security of supply for customers, combined with regulation of monopoly networks activities and the encouragement of renewables generation technologies.

The White Paper contains over 130 Government commitments that must be delivered. These vary from specific and relatively small scale actions to reinforcement of existing policies and elements of a wider policy framework. They have been broken down into 10 overall work streams as follows:

- Climate change
- Reducing UK Emissions
- CHP
- Renewables
- Social issues - including fuel poverty
- International Energy Relations
- Innovation
- Education
- Skills and Research
- Transport
- Security of Supply and
- Delivery Partnerships

The Government has also established a Sustainable Energy Policy Network (SEPN) to ensure co-ordination across Government Departments and including the Scottish and Welsh "devolved administrations" (effectively regional or state level Governments) and Ofgem. The SEPN has the responsibility to monitor and report on the implementation of the policy objectives on an annual basis.

Following implementation of the Utilities Act 2000 both the Secretary of State (DTI) and the Gas and Electricity Markets Authority (Ofgem) have the secondary duty to secure that all reasonable demands for electricity are met. (As noted above the primary duty is to protect the interests of consumers by promoting effective competition wherever possible).

The JESS group, chaired jointly by DTI and OFGEM, brings together contributions from DTI, OFGEM, National Grid Transco (NGT or NGC) and the Foreign and Commonwealth Office (FCO) on energy security. The work that JESS undertakes on security of supply is focussed on the medium to long-term, at least seven years ahead, rather than the short-term.

The JESS is not a policy formation group, it seeks to present market information rather than to draw firm conclusions, as much of this information is capable of being interpreted in a range of ways. Within the bounds of commercial confidentiality, JESS aims to ensure that energy companies, investors and consumers have access to as wide a range of information as possible.

Subsequently, the Energy Act 2004 required the Secretary of State to report to Parliament annually from 2005 on security of supply. The annual report, to be compiled jointly with Ofgem, is required to cover the availability of electricity and gas for meeting the reasonable demands of consumers in Great Britain in the short and long term, including assessments of electricity generation, transmission and distribution capacity and gas infrastructure.

In addition to the national reporting arrangements described above, the UK is required by EC legislation to monitor electricity security of supply issues and to publish a report every two years. European legislation also requires Member States to take "appropriate measures" to maintain a balance between demand and availability of generation capacity, in particular by encouraging the establishment of a wholesale market, which provides price signals for generation and consumption.

A key part of the framework for energy policy and the security of supply in particular is that transmission licence holders are required by their licence to publish a statement that sets out their plans for the development of the network during the next seven years (or 10 years for gas). Until recently National Grid Transco's Seven Year Statement has covered only England and Wales, in line with NGT's present duties. However, from May 2005 the Seven Year Statement has been modified to include Scotland, in accordance with NGC's designation as GB system operator under the new British Electricity Trading and Transmission Arrangements (BETTA). Again, it is hoped that the publication of information will provide a stimulus to ensure that the market reacts to forward pricing signals by bringing forward plans for sufficient additional capacity in an appropriate timeframe.

Suppliers have no overall requirement to purchase sufficient electricity to meet their customers' demand under a given set of demand conditions, but would potentially face very high imbalance charges through the operation of the balancing mechanism in the event that demand was significantly greater than they were able to contract in either long, medium or short term markets. Furthermore, in advance of each winter (peak demand) period, NGT publishes a review of potential sources of supply and of likely demand, in order to provide to the market an assessment of the supply/demand balance under different demand scenarios. Suppliers do have additional obligations in respect of purchasing electricity from renewable sources.

There are two broad regulatory incentive schemes in the UK that have some relevance to the incentivisation of EE R&M schemes in India. The first is the operation of the overall network efficiency incentive, which is a revenue cap with an incentive for operational efficiencies that has been in existence for almost 20 years. The second is an additional incentive to provide high quality network outputs that applies to distribution network operators (DNOs) and known as the information and incentives project (IIP). This is a much more recent scheme that provides additional revenue to DNOs if they meet specified output performance targets.

Establishment of a performance baseline

Both schemes rely heavily on the establishment of accurate data in relation to existing costs and levels of performance, as follows:

- ***Overall network efficiency scheme:***

  For the overall network efficiency scheme the baseline is measured through:

  - monitoring of audited regulatory accounts;
  - completion of detailed questionnaires on past and forecast operating and capital costs;
  - detailed asset management plans that companies are required to prepare and keep up to date;
  - the results of benchmarking with other companies; and
  - consultancy reviews of projected efficiency gains based on best practice operating techniques.

IIP

For the IIP scheme the baseline is measured through company reporting of performance, with a licence obligation on companies to "establish and maintain appropriate systems, processes and procedures to measure and record specified information."

The regulator (Ofgem) has power to nominate "an examiner" to audit these systems and has in the past made extensive use of this power to ensure common reporting systems.

In addition, Ofgem has issued guidance to companies to ensure harmonised reporting, in the form of the "Quality of Service Regulatory Instructions and Guidance" version 5 of which contains definitions, instructions and guidance for collating information.

For the 2005 to 2010 incentive scheme Ofgem set performance goals based on a benchmark level of actual performance in 2004/5 or 2001/2 (the year the previous incentive scheme was introduced) whichever was better.

Setting the appropriate performance incentive

- ***Overall network efficiency scheme***

  In the UK, performance incentives in the general network incentive scheme have traditionally been set for the residual life of the revenue control, which is almost invariably 5 years. Controls are essentially revenue caps, set on the basis of forward projections of operating and capital costs (plus allowances for the cost of capital and depreciation) with an inflationary allowance, limited variability in relation to the anticipated number of units transmitted/distributed (compared with the forecast volume) and an X factor designed to take account of the efficiency gains that should be made by an efficiently run company.

  If the network operator incurs costs higher than the efficient level set by the regulator he will fail to earn the allowed return on capital. If it incurs costs below the efficient level set by the regulator it can earn additional profits and thus the network operator is incentivised to reveal the efficient level of costs.

In setting the anticipated or normative efficiency factor the regulator is guided by consultants appointed to advise him on the prospective application of best practice techniques, by the results of a benchmarking study (normally carried out by consultants and designed to reveal the efficiency "Frontier") and by the company's individual and the companies' historic performance.

Ultimately, as in Australia, these factors are treated as a guide and the end result tends to be a process of negotiation, with each company claiming that specific circumstances are likely to prevent it from meeting the regulator's target. Therefore, incentives are set in relation to each company's specific cost base, asset profile and investment requirements.

In the UK the regulators accept the logic of the argument applied in Australia that the most appropriate level of benefit sharing from additional or "outperformance" efficiency gains is 70/30 in favour of consumers.

- ***IIP***

The IIP is essentially an output based incentive scheme, with DNOs able to earn additional revenue for performance above and beyond the "normal" anticipated efficiency improvement in relation to 3 key quality of service measures: the number of interruptions, the duration of interruptions and the level of customer service, as measured by telephone response times.

As such it is not an investment incentive, as such, but provides DNOs with an additional incentive to invest if they consider that capital expenditure would be likely to ensure that they would meet their performance incentive.

In setting the incentive to apply from 2005 to 2010 Ofgem assumed a 0.5% per annum "normal" improvement in the benchmarks for the number of customers interrupted, to reflect developments in technology and best practice.

Up to 2% additional revenue was then available for fully meeting performance incentives, broken down as follows.

Annex 8, Table 3

Target	Maximum revenue exposure to the incentive scheme (%)
Duration of interruption	1.25
Number of interruptions	0.5
Telephone response	0.25

Measurement of improvements achieved

In order to close the loop on the incentive schemes the UK regulator uses similar techniques to the Australian regulator. For the general network incentive scheme this includes:

- audited regulatory accounts; and
- comparisons with other companies.

For the IIP scheme applying to electricity DNOs, this includes annual reports on the quality of service achieved, on the basis of reporting systems that have been audited and standardised, to ensure consistency with other companies.

Ofgem's view of the scheme is a very positive one and it stated in October 2007, "since the introduction of the incentive scheme in April 2002 the underlying average number of customer interruptions per 100 customers has fallen by 10 per cent and the number of customer minutes lost has reduced by 4 per cent."

Controls and incentives for coal fired generation

At present incentives exist only to support the development of renewables generation and the various mechanisms are set out in more detail below. There are no incentives to encourage rehabilitation and modernisation of old coal fired plant, though a number of generators have chosen to rehabilitate and modernise such plant for commercial reasons. This has mainly involved the fitting of flue gas desulphurisation (fgd) equipment designed to prolong the life of existing plant through reductions in emissions of SOx and NOx as a result of progressively reducing limits on such emissions inspired by the UK's overall programme of compliance with its Kyoto Treaty obligations.

Such schemes are very expensive but have been assessed by the concerned generators as commercially beneficial. There is no requirement for regulatory approval of such expenditure because wholesale prices are completely liberalised.

Other controls and incentives applicable to generation

As indicated above there are no funding mechanisms to support rehabilitation and modernisation of old coal fired power stations in Great Britain, rather the generators consider the economic merits of specific investments on the basis that there will be a commercial payback through the (unregulated) prices achievable (or expected to be achievable) in the wholesale market.

The most common work carried out by generators has been the fitting of flue gas desulphurisation equipment designed to reduce the level of emissions and to permit plant to run for longer periods within the allocated emissions limits.

There is however a range of incentives and market based mechanisms designed to support renewables technologies, in the form of supplier (retailer) purchasing obligations and tradeable certificates, capital grants and taxes, as described below.

- ***Renewable Obligation***

  The primary support mechanism for Renewable Energy in the UK is the Renewables Obligation (RO). Eligible renewable generation is credited with a Renewable Obligation Certificate (ROC) for each unit of output (MWh) produced.

  The RO places an obligation on licensed electricity suppliers to present a number of ROCs equivalent to a percentage of the electricity they have supplied, or pay a "buy-out" price for any shortfall. The buy-out price was originally set at £30/MWh, and is indexed linked. Funds accumulated from the buy-out are then "recycled" back to those suppliers based on the number of certificates presented. Thus, the value of a ROC is the buy-out price + recycle fund.

This mechanism means that the market price for ROCs is set by supply of renewable generation and demand (as defined by the obligation). There is a market for ROCs, and they can be traded separately from the electricity produced.

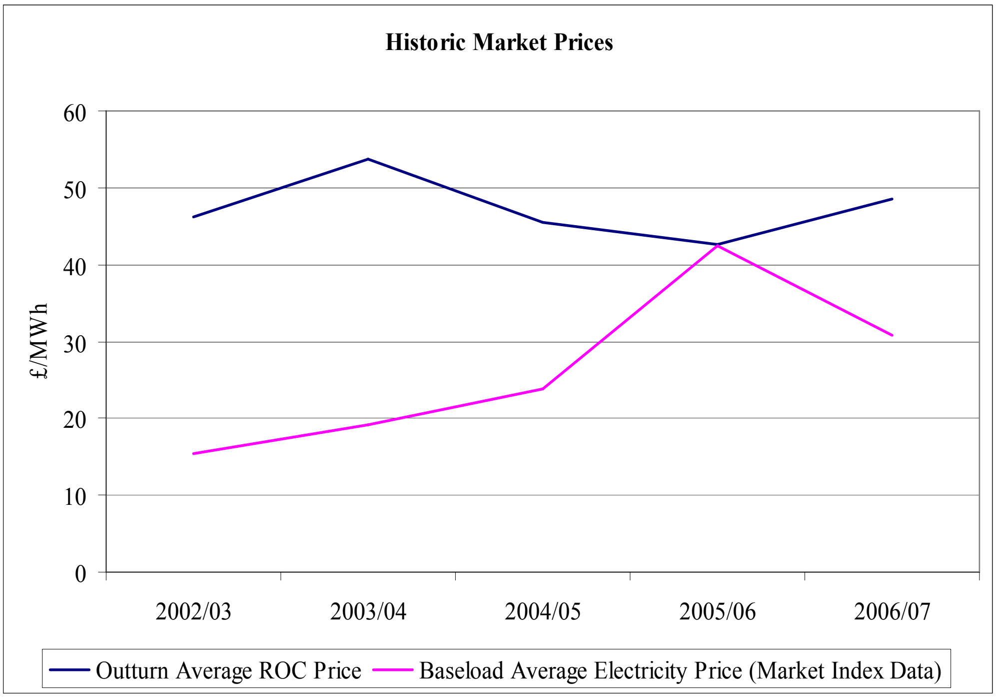
It can be seen from Figure 3 of this Annex that ROC prices have typically been greater than power prices over the last 5 years and so make a significant contribution to the economics of renewable generation projects.

The obligation came into force in April 2002, with the level of the obligation increasing every year to 2015. The level of the Supplier Obligation to 2015 is shown in Figure 4 of this Annex and there are proposals to extend the target to 20% by 2020.

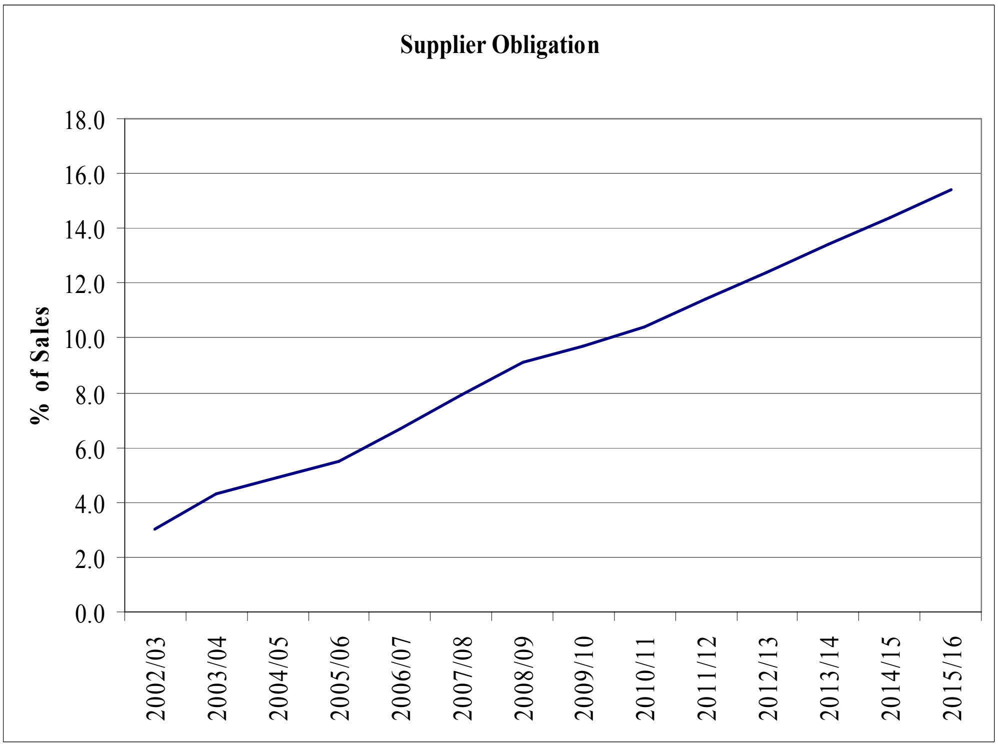
Although the Renewable Obligation has provided renewable generation with a significant additional income stream, the future income from ROCs is subject to both market and political risk.

There are current proposals which could significantly change the operation of the RO. The most significant change would be to move from the RO being technology neutral (1 ROC is awarded for each MWh of eligible renewable output) to a system where the number of ROCs awarded would be technology dependent with between 0.25 ROCs per MWh awarded for the most economic technologies to 2 ROCs per MWh awarded for more expensive technologies.

Annex 8, Figure 3: ROC and Power Prices in Great Britain



Annex 8, Figure 4: Renewable Obligation on Suppliers



- ***Climate Change Levy***

  The Climate Change Levy (CCL) is a tax on the use of energy in industry, commerce and the public sector, which acts in conjunction with offsetting cuts in employers' employee National Insurance (welfare tax) contributions if employees implement certain energy efficiency/carbon saving measures, such as contributions to renewables generation projects.

  The value of the levy is currently £4.41 per MWh and this is reviewed by the Treasury every year and generally increased in accordance with inflation, although this is not guaranteed. Thus, there is some political risk associated with the additional revenue achieved by a renewable generator through the CCL.

  Unlike ROCs, the value of the CCL cannot be traded separately from the electricity with which it was supplied.

- ***Capital Grants***

  The UK Government has provided capital grants for nascent technologies such as offshore wind, tidal and marine generation projects. These have been allocated on a project specific basis to support the development of these technologies.

- ***Climate Change Agreements***

  Climate Change Agreements provide industrial companies in the UK with an incentive to reduce their energy intensity by providing them with a rebate of up to 80% against their liability to pay the climate change levy (CCL) described in above, in return for a programme of emissions reductions on the basis of targets individually negotiated with the UK Government. These targets are usually subject to a form of umbrella agreement for different industry associations that provides a form of collective liability, as well as helping to ensure consistency across each industrial sector.

Targets are set on the basis of two-yearly interim milestones (2002, 2004, 2006 and 2008) and a final target for the year 2010. For each milestone, individual sites have to report energy and production data to their sector association, though independent crosschecks can also be undertaken by the UK Government.

As far as enforcement is concerned, the key feature of CCAs is that they are both based on a collective liability principle through the umbrella agreement and an individual liability principle through the underlying agreement signed by individual sites. More specifically, if the sector target is met, there is no further action. Otherwise the non-compliant sites are identified, are not re-certified for the discount and lose their right to the climate change levy exemption for the next two years (though they don't have to pay back the rebate corresponding to the non-compliance period). At the end of the next milestone, they could again benefit from the discount if they succeed to comply with the next interim target.

In 2010, if a site fails to comply with its target, it will have to pay back the whole of the levy exemption sum it has benefitted from.

The scheme is essentially a tax rebate, introduced in response to pressure from large industrial customers and many critics have argued that the negotiated targets were too easily achieved.

It is clear that major energy efficiency savings and investments have been achieved. For example, the British Cement Association (BCA), in a response to a survey from the UK Government's National Audit Office, estimated that its members had made or were committed to investments decisions totalling around \$1bn in the replacement and refurbishment of kilns and equipment to support combustion of alternative bio and non-bio fuels. This compares with a full levy liability of around \$50m pa for the cement industry, rebated to around \$10m if the targets are achieved – roughly a 25 year payback period on the investments made, on the basis of tax savings alone.

The BCA reported that, at the time of the monitoring stage 3 assessment in 2006, its members had, collectively, achieved savings of energy intensity (measured as kWh per tonne of cement producer) of around 28% compared with a 1990 baseline.

Unfortunately, it is, in practice, extremely difficult to separate the impact of the CCAs from the impact of rising fuel prices during the last few years, which the British Cement Associations stated to have been a more significant factor in its members' investment decisions. In addition, the BCA drew attention to the positive impact of the EU's emissions trading scheme (EU ETS) in also promoting such efficiency enhancements and investments and to the possibility that the existence of the levy helped to displace domestic manufacturing and replace it by additional imports.

Market Framework

There are no special arrangements in the GB power markets for coal fired generating capacity and none that might in any way be described as providing a support to rehabilitation and maintenance of old coal fired power stations. Such work must be assessed and carried out on an entirely commercial basis against the generator's forecast of wholesale market prices and his estimate of the costs of such work.

It should be noted however that, unlike in India, coal fired generation capacity is not price controlled and is therefore able to recover short run revenues at the level of the system marginal price and long run revenues at the level of the new entry price. (By this we mean at the conceptual level of SMP, given that SMP is no longer an administered feature of the market - as it was during the period of operation of the old Pool based market).

For renewables generation, there are no special arrangements in the wholesale market, other than those items of additional financial support available under the Renewable Obligation and Climate Change Levy that are described above. In other respects renewable generation is treated the same as conventional generation and has to interact with and operate within the rules of the GB power markets.

A high level overview of the key principles governing the GB market is provided below and shown diagrammatically in Figure 5.

In addition to trading power, renewable generators are able to trade ROCs, which is an extremely illiquid market. Also, the rules surrounding CCL mean that it is difficult for renewable generators to trade generator output and extract the value of the CCL exemption from different counterparties. Both of these provide additional barriers to renewable generators in terms of actively trading generation output in the power mark

- ***Traded Market***

  In general the market is a bilateral market and most volumes are traded on the basis of specifically negotiated long term contracts (so-call structured deals). However, there are also possibilities to trade through brokers or through exchanges, which naturally involve standardise contractual forms, volumes, durations etc in order to enhance liquidity and facilitate rapid exchanges. Non-physical players may also be involved in the traded market.

- ***Self despatch***

  Counterparties (generators and suppliers) decide individually how much power they physically plan to inject and withdraw from the system, though suppliers are obliged to try to balance the inputs made on their behalf (by their contracted generators) and the off-takes made by their customers. To the extent that they do not or are unable to do so they must make an appropriate contribution to the costs of balancing power bought by the system operator, for the purpose of maintaining the physical integrity of the system (see below).

- ***Notification***

  Generators have to submit physical and contractual notifications to the system operator (SO) and market operator respectively before gate closure, which is set at one hour before the start of each half hour settlement period.

  The physical notification to the SO gives the continuous planned output of individual physical Balancing Mechanism Units (BMU). Notification is the expected power that will be injected or withdrawn at an individual BMU level. Generation BMUs are usually specified at individual generation set level, although individual wind turbines and other "smaller" generators at a single location would typically be grouped into one BMU. Parties have to follow their FPN positions. Any *intentional* fluctuation from FPN is a breach of the grid code, and as such a breach of the conditions of their licence. Clearly scope is provided to allow for the unpredictable nature of the output of many renewable generators.

  Counterparties also have to provide notifications of contracts before "gate closure." These are energy positions over each half-hour period. Contracts have to be notified to be taken account in the imbalance settlement processes.

- ***Entry and Exit***

  Counterparties must have rights to inject and withdraw power. The rights are granted at specific entry (and exit points). The system is based on the "ticket to ride" principle rather than point to point transportation.

- ***Balancing Settlement***

  Counterparties are incentivised to balance their physical and contractual positions. Imbalances between these positions are subject to cash-out prices. There is a dual cash-out price depending on whether the counterparty is long or short (in relation to their physical and contractual position), with the prices typically being equal or at a premium to the spot market price.

- ***Balancing Market***

  The responsibility for balancing supply and demand is split between the System Operator (SO) and market participants. The SO has responsibility for balancing the system between gate closure (1 hour ahead) and real time, but due to the issues associated with plant dynamics it may be necessary for the SO to take actions outside this timescale.

  Market participants can only manage system balancing (at a portfolio level) up to gate closure, since at this point they must declare the physical operation of plant through the submission of FPNs.

  Market participant balancing can only be undertaken through the bilateral traded market (OTC and exchange trading) as there is no day-ahead auction or other centralised Balancing Market mechanism.

  Limited market liquidity has been seen as a problem especially in the prompt markets, and may be one of the drivers for consolidation of the industry into a number of vertically integrated portfolios (generation and supply). However, the ability to trade up to gate-closure ensures that at least in theory the market should allow economic scheduling across the industry close to real time.

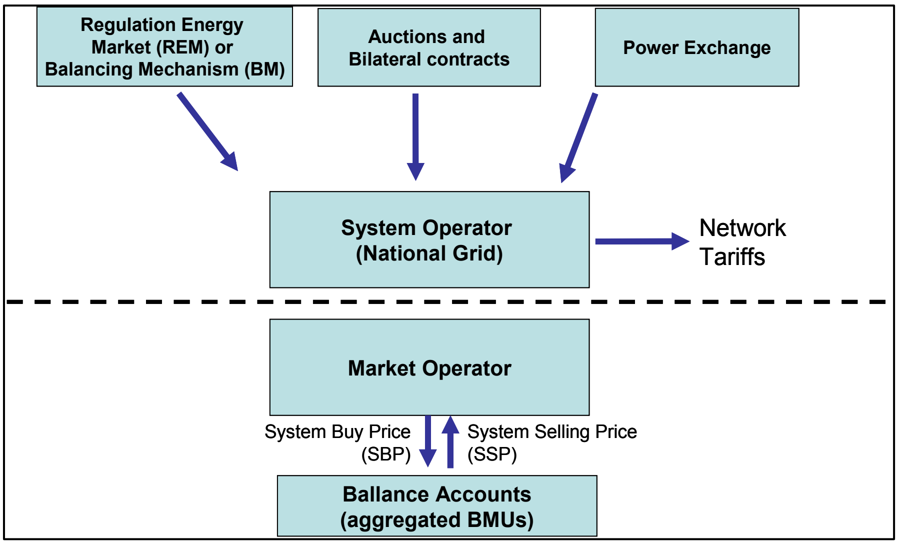
The GB SO (there is only one control area within the GB power market) has sole responsibility for balancing the system after gate closure. The system operator is responsible for residual energy balancing. This means that the system operator is responsible for resolving any energy balancing, required as a result of differences between demand and generation FPNs, as well as any imbalances due to demand or generation fluctuations and unplanned outages that result in imbalances occurring after gate closure (differences between physical output and FPN).

In addition the System Operator is responsible for system balancing – maintaining supply quality (stable voltage and frequency) and supply security (transmission constraints). The system operator has a number of tools for system and energy balancing. These include accepting bids or offers in the Balancing Mechanism, entering into contracts with market participants for energy or ancillary services, and energy trading in the power markets.

The Balancing Mechanism (BM) is the market that exists between gate closure and real time. The BM is a monopsony market with the SO as the sole counterparty. Market participants (predominantly generators, but also large controllable loads) can submit bids/offers to decrease/increase their output from their notified FPN level. The BM is a pay as bid market. Whilst the BM is used as a Balancing Market, it is also used for the delivery of other system operator actions such as Ancillary Services.

Although some flexible plant can derive significant revenues from the provision of ancillary services, and the provision of flexibility to the SO through Balancing Mechanism Bids/Offers, variable renewable generation are unlikely to provide any significant BM participation.

Annex 8, Figure 5: Overview of the Balancing Power Market in Great Britain



The traded markets comprises both over the counter (OTC) and exchange based trading, which allows generators and suppliers to adjust their commercial positions ahead of real time down to a half hourly granularity.

The GB power markets do not have a day-ahead auction, so all trading has to be undertaken through individual transactions.

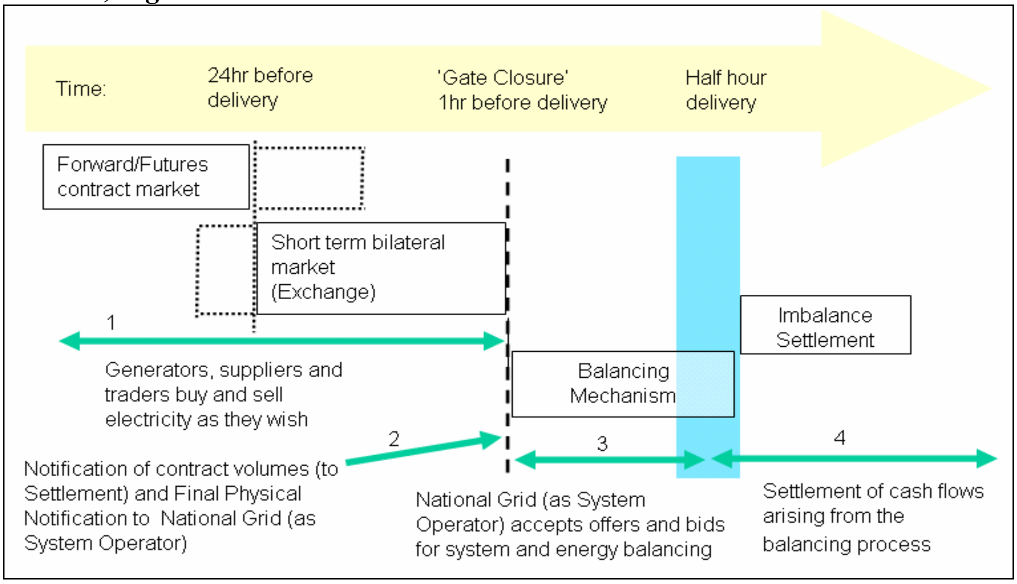
Market participants can control balancing of their positions up to gate closure (1 hour ahead of the start of each half-hour settlement period), at which point all contracts have to have been notified to the market operator. In principle, it is possible to trade up to an hour ahead of real time, although in practice the power exchange, where most short term trades are undertaken, closes 1.5 hours ahead of real time.

There is limited liquidity across the different power markets, reflecting the vertically integrated nature of most of the major players. For instance only 2% of electricity demand is traded as half hour products through the power exchange. Market liquidity can prove restrictive in terms of the ability of counterparties to use trading to balance their positions through the traded market. This is particularly true for renewable generators subject to output uncertainty such as wind generators, where traded positions need to continue to be adjusted approaching real time, as forecasts of output are updated.

The lack of a single gateway for trading means that counterparties typically have to maintain a number of different trading agreements and support these with appropriate credit, which can be a significant overhead for an independent generator. In addition maintaining a 24 hour trading operation requires a relatively large operation, which is unlikely to be viable for individual renewable generators.

In addition to trading power, renewable generators are able to trade ROCs, which is an extremely illiquid market. Also, the rules surrounding CCL mean that it is difficult for renewable generators to trade generator output and extract the value of the CCL exemption from different counterparties. Both of these provide additional barriers to renewable generators in terms of actively trading generation output in the power markets.

Annex 8, Figure 6: The Great Britain Power Markets



As a result of the complexities and overheads of trading, many independent renewable generators enter into long term off-take contracts with large utilities, avoiding the complexities of interacting with the traded market or the power market arrangements (such as notifications, imbalance etc).

In addition many independent renewable projects are project financed and so require some guarantees on future revenues streams (provided through long term off-take contracts) to support debt financing of the project. This is an additional factor that has lead many independent renewable generation projects to enter into long term power off-take arrangements.

Purchasing and Pricing

Since 2002 there has been no direct regulation of retail power prices in the UK and retail prices are controlled only by the effects of the market and by competition law requirements applicable to dominant market actors. This position has held with firm support from the UK energy market regulator, Ofgem, despite strong pressure from consumer related organizations at times of price increases driven by worldwide increases in fuel prices.

As a result there is also no regulation of wholesale prices and the price levels and contractual structures agreed between generators and suppliers are an entirely commercial (and confidential) level. As indicated above suppliers aim for a mix of long and short term contracts designed to give them the flexibility to respond to the market but also to take advantage of the lower costs of long term guaranteed purchases. In this context the rehabilitation and modernization of coal fired plant is therefore entirely a matter for each generator, based on his overall portfolio, his emissions limits, his arrangements with suppliers and his own forecast of prices prevailing in the UK wholesale market.

Suppliers have no overall requirement to purchase sufficient electricity to meet their customers' demand under a given set of demand conditions, but would potentially face very high imbalance charges through the operation of the balancing mechanism in the event that demand was significantly greater than they were able to contract in either long, medium or short term markets. As indicated above, suppliers do have additional obligations in respect of purchasing electricity from renewable sources.

Reserve capacity

The Government does not set specific targets for reserve capacity or capacity margins, preferring to leave such decisions for the market place, though it does express the view that security is best guaranteed by diversity.

However, the Government (in the form of the Department for Business, Enterprise and Regulatory Reform) and the regulatory authority for the energy industry (Ofgem) are working together in areas related to the security of supply through the Joint Energy Security of Supply working group (JESS). In doing so they seek to inform the market of supply and demand scenarios over the medium term rather than interfering with the operation of the market mechanism.

Previously, under the Electricity Pool for England and Wales, which was the wholesale market established at the time of privatisation in 1989/90, there was an explicit capacity incentive scheme.

This scheme operated on the basis that capacity payments were paid to generators in accordance with a formula that considered the value of unmet demand (value of lost load) and the probability that there would be insufficient availability to meet demand (the loss of load probability); this can be expressed in its simplest form as VOLL x LOLP. That is, the value of lost load multiplied by the loss of load probability.

Although this would appear to have been a scientific methodology there was no certainty in relation to the value of lost load, which was in effect administratively determined and arguably set too high, whilst the Loss of Load was beset by arguments that the programme used to calculate the probability over-estimated the probability the available plant would "drop off" the system (so-called disappearance ratios).

Whilst the scheme was arguably successful in maintaining a healthy reserve margin, eventually the Government and regulatory authority decided that it imposed excessive costs on the system and consumers and the new wholesale markets (NETA/BETTA) were designed without an explicit capacity incentive, leaving customers and suppliers to decide on the value of lost load through their supply contracts and purchasing arrangements with generators. The UK capacity margin has reduced considerably in recent years since the removal of the explicit capacity payment and the have been several instances where the system operator has issued a "Notice of insufficient margin." So far however no actual capacity shortfalls have been experienced and it is therefore possible to argue that the market has reacted in time and new capacity continues to be added to the system.

USA

Industry structure and broad policy framework

The regulatory system in the USA, like that in India, has historically operated on the basis of cost plus regulation, although a number of states have introduced incentive based regimes in recent years. The USA has a significant volume of coal fired plant, at present around 50% of capacity, though this is expected to grow to around 57% during the next few years.

Clean air, emissions reductions, clean and efficient power plant and the role of renewables are extremely divisive issues in the USA and there have been a number of attempts to introduce legislation that would mandate and/or incentivise cleaner and more efficient operation of coal fired power plant. This led to a series of piecemeal proposals for measures to enhance efficiency, promote the development of cleaner generation sources and control emissions

For example, the proposed Clean Power Plant Act of 2001 and the proposed Acid Rain Control Act both sought to require reductions in emissions from power plant and to modify the Clean Air Act of 1990.

Similarly, the proposed Clean Power Plant and Modernization Act of 2001, sought to set tough targets for the average efficiency of coal fired plant and to establish a programme of incentives, such as accelerated depreciation and a Clean Air Trust Fund to support research and development programmes and commercial demonstration projects (e.g. for clean coal technologies). This Act also sought to end the "grandfathering," of old plant from modern standards on the basis that exemptions have led to significant life extensions for such plant and have prejudiced the development of new and more efficient plant

Although this Act does not appear to have been implemented it is worth noting a number of the specific proposals made:

- To end the "grandfathering" exemption on emissions from old plants and to provide that within 10 years, all units in operation must achieve a combustion heat rate efficiency of not less than 45%.
- To provide that new plant, commissioned after a period of 10 years units should achieve a combustion heat rate efficiency of not less than 50%;
- To provide for accelerated tax depreciation for utilities that cut emissions and upgrade their plants to 45% to 50% efficiency (from the current average of only 33%); and
- In order to pay for the proposed incentives it was proposed that there would be a levy of 30 cents per megawatt-hour for electricity produced by specified coal fired electric generating units.

In order to stem the flow of criticism of its energy policies and to demonstrate that it was operating in a consistent and coherent manner, the US developed a National Energy Plan, under the leadership of Vice President Dick Cheney, which was later translated into a national energy policy, enshrined in the Energy Policy Act of 2005, as reviewed below.

Because the US, like India, operates on the basis of a Federal system of Government, this Section reviews first, the framework for energy policy, incentives and controls operating at the Federal level and then reviews specific examples of controls and incentives in operation at State level.

Energy Policy

According to Dinos Stasinopoulos of the European Commission in a review of the US National Energy Plan produced by Vice President Dick Cheney and published by the CEPMLP, "dissatisfaction with the energy policies of the previous administration has led the new US administration to consider a more free market approach to replace existing policies. The (new) US energy plan is a comprehensive mix of expansion of energy supply and other initiatives, with a large number of recommendations, executive orders, directives to federal agencies and proposals for congressional action. According to the plan, the need to reduce external dependence takes priority over all other energy objectives. This dependence leaves the country vulnerable to price shocks and interruption of supply."

Subsequently, the national energy plan was translated into practice though the various provisions of the Energy Policy Act of 2005 (EPA). The EPA is now the major instrument to promote clean power generation, both from coal and from renewable sources of energy and its provisions and the various subsidiary programmes it delivered are summarised below.

In addition, the US Government announced in November 2006 tax credits of approximately \$1.6bn for clean coal technologies, which are expected to raise efficiency rates to between 55% and 60%.

Federal Level Controls and Incentives

As indicated above, the Energy Policy Act of 2005 makes provision for a major series of support programmes in relation to coal fired and renewable generation capacity. At this stage it is perhaps premature to comment on the success of these programs.

- ***The Clean Coal Power Initiative (CCPI).***

  The CCPI authorizes \$200 million per year from 2006 to 2014 as the Federal Government's share of a program designed to support clean coal demonstration projects, on the basis of detailed criteria set out in the Energy Policy Act. Existing plants must increase their thermal efficiency to ensure their eligibility. The detailed criteria for both new and existing units are set out in Table 3 of this Annex.

Annex 8, Table 4 – CCPI efficiency targets for new and existing coal fired power plant in the USA

CPI Program	Other technologies 2020 milestones	IGCC technologies 2020 milestones
New units		
NOx	0.8lbs/mbtu	0.5lbs/mbtu
SOx	97%	99%
Efficiency levels	• 43% for coal at > 9000Btu • 41% for coal >7000 Btu but <9000 Btu • 39% for coal < 7000 Btu	• 50% for coal at >9000 Btu • 48% for coal >7000 Btu but <9000 Btu • 46% for coal <7000 Btu
Existing units		
Efficiency levels	• 7% increase for coals >9000 Btu • 6% increase for coals >7000 Btu but < 90000 Btu • Increase of 4% for coals <7000 Btu	

* Integrated coal gasification combined cycle
Source: The Coal Utilization Research Council

- ***The Clear Air Coal Program***

  This program authorized a $3 billion commercial deployment program in the form of loans, cost sharing, or cooperative agreements to encourage the generation of new sources of advanced coal based power and upgrade existing sources of coal based power by retrofitting existing plants with pollution control equipment, such as flue gas desulphurisation equipment.

- ***Coal R&D Program***

  This program authorizes $1.1 billion over three years in funding for the R&D clean coal program in the Department of Energy.

- ***Carbon Capture Research and Development Program***

  This program authorizes $90 million over 3 year period to the Department of Energy to develop and apply carbon capture technologies to both new and existing generation units.

- ***Incentives for Innovative Technologies***

  The program provides loan guarantees to “Innovative Energy Technologies” that avoid or reduce pollutants and greenhouse gases.

- ***Power Sector (IGCC) Tax Credits***

  This incentive creates an investment tax credit for integrated coal gasification combined cycle ("IGCC") generation capacity and advanced combustion facilities that are certified by the Treasury, in consultation with the Department of Energy. The tax credit program requires that all three ranks of coal (bituminous, sub bituminous, and lignite) are included among the selected IGCC projects.

- ***Seven Year Amortization for Pollution Control Equipment***

  This initiative authorizes a seven year recovery period for the cost of certain certified air pollution control facilities associated with electric generation plants (mainly coal fired that were not in operation before January 1976).

- ***Renewable Electricity Production Credit***

  The Renewable Electricity Production Credit ("REPC") commonly referred to as the Production Tax Credit ("PTC") is a volumetric per kWh federal tax credit for electricity generated by qualified energy resources. The REPC provides a tax credit of 1.5 cents per kWh, adjusted annually for inflation, for wind, solar, closed-loop biomass, and geothermal resources. Electricity from open-loop biomass, small irrigation hydroelectric, landfill gas, municipal solid waste resources and hydropower receive half that rate. These credits, which were originally introduced by the Energy Policy Act of 1992, were effectively extended by the EPA 2005 until the end of 2008.

- ***Clean Renewable Energy Bonds***

  The EPA permits State and local governments, cooperative electric companies, clean renewable energy bond lenders and Indian tribal governments to issue "clean renewable energy bonds" ("CREBs") to finance certain renewable energy and clean coal facilities. CREBs are new form of tax credit bond in which interest on the bond is paid in the form of federal tax credits by the US government, in lieu of interest paid by the issuers. CREBs, therefore, provide qualified issues/qualified borrowers with the ability to borrow at a 0% interest rate. Qualified projects include facilities of wind, closed loop biomass. Open-loop biomass, geothermal or solar, small irrigation, landfill gas, waste combustion, refined coal, and qualified hydro.

Summary

Despite these various initiatives and the further initiatives described below, operating at state level, there has been relatively little development of new coal fired generating capacity in recent years. The attached extracts from an article published in the online newsletter, Stateline.org summarises the polarisation of the debate between those arguing for support for enhanced efficiency and clean coal technologies and those arguing primarily for reduced emissions.

> "Coal-producing states …. are feeling squeezed as efforts to combat global warming outpace technology needed to make the nation's most abundant fossil fuel burn more cleanly. In 2007, proposals for 59 coal plants were scrapped in 24 states, either by state regulators concerned about the effects of carbon-dioxide emissions or by power companies worried about the future costs of pollution.

Now….major mining states are intensifying calls to expand technologies to reduce carbon-dioxide emissions from coal power, including a method that turns carbon dioxide into a synthetic natural gas, called gasification, or to store the emissions underground, through a process called sequestration.

Seventeen states already provide financial incentives to encourage cleaner coal-burning technology. North Dakota has the only plant that gasifies coal and pumps the synthetic natural gas to pipelines that supply the eastern United States — and also captures some of the carbon-dioxide emissions.

The Federal Department of Energy has helped build demonstration plants in Indiana and Florida that gasify coal to create electricity, and more than 30 proposed power plants would use similar technology, according to a February report from the National Energy Technology Laboratory (NETL). Only three of them are in the final stages of planning or nearing construction, NETL reports. Although 150 new coal-fired power plants were proposed between 2000 and 2006, the bulk of those projects has been delayed or cancelled, according to an October 2007 report by NETL. More than 36,000 megawatts of electricity was scheduled to come from new coal-fired power in 2007 — enough to power roughly 36 million homes, just 4,500 megawatts was actually produced, NETL found.

State governments already are leading the movement to curb greenhouse gases, with 26 now requiring that a percentage of electricity come from renewable sources, such as wind and solar. Those include five of the top 10 coal-producing states — Pennsylvania, Montana, Texas, Colorado and Illinois.

Nearly all of those 26 states also have signed on to three separate, regional cap-and-trade systems that will eventually require cuts in carbon-dioxide emissions from power plants and other industrial sources. Under those systems, coal-fired power plants would be given or have to buy credits for the carbon dioxide they produce and pay for additional credits if they do not meet reduction targets.

Pressure to cancel projects also has come from outside states where proposed power plants eventually were abandoned. Attorneys general from eight states urged Kansas regulators to turn away power plants, arguing that the global climate change requires action at the state and local levels.

Utility companies also have pulled the plug on many of their own plans because of public backlash and the potential costs of carbon dioxide regulations under a cap-and-trade system — the same reason that banks are setting tougher new standards for financing new power plants.

After consulting with both power companies and environmentalists, international financial institutions Citigroup Inc., JPMorgan Chase and Morgan Stanley announced Feb. 4 they would begin weighing the economic and environmental risks of underwriting electric-power projects. Bank of America made a similar announcement the following week.

Industry advocates and politicians in large mining states acknowledge that environmental concerns have made it tougher to build new power plants. But coal's abundance and low cost ensure it will be needed to meet the nation's growing demand for electricity, they argue.

Although President Bush has repeatedly pronounced his support for innovations in coal power, the Federal Department of Energy reported in January that it was cancelling a partnership with industry to build a $1.8 billion demonstration project in Illinois to develop sequestration and gasification technologies. "

State level controls and incentives

This section describes a number of interesting state level programmes designed to support cleaner coal fired and renewables generation technologies. Information on coal programmes is derived primarily from the Coal Utilization Research Centre. Information on renewables programs has been limited to California, Texas and New York, because all states have programs and it is not considered necessary to cover the full range or programs across the whole of the USA.

- ***Coal Plant Incentives***
  - **Alaska**

    The State of Alaska provides assistance (in the form of bond financing through Alaska Industrial Development and Export Authority) to a clean coal project from a "plant or facility demonstrating technological advances of new methods and procedures and prototype, commercial applications for the exploration, development, production, transportation, conversion, and use of energy resources". Projects, however, must be able to demonstrate that they will be able to generate revenue streams to repay the bond.

  - **Colorado**

    The State of Colorado adopted legislation in 2006 to encourage the construction of clean coal technology projects. The legislation provides for a variety of incentives, including waivers from the Public Utility Commission ("PUC") certificate of public convenience and necessity, full recovery from customers (including capital and operating costs) waivers from the PUC competitive acquisition rules and ensuring that the PUC shall approve the power purchase agreements that utilities shall enter in with the generators and ensure recovery in these costs from rates through rate adjustment clauses on a timely basis.

  - **Illinois**

    The State of Illinois provides direct financial assistance (with a maximum of US$100 million) towards the capital costs of buildings, structures, durable equipment and land at new facilities. To qualify, the facility should be built after 2001, create 400 MW of new generating capacity, use coal or gases derived from coal as its primary fuel source and support the creation of at least 150 new Illinois coal mining jobs, or, use coal gasification or integrated coal gasification combined cycle technology ("IGCC").

    Additionally, the State offers to new or expanded electric generating facilities using coal to qualify as "High Impact Business" designation to receive tax exemption on build materials and equipment as well as .some property taxes.

- **Indiana**

  The State provides for both "Tax Credits for IGCC Facilities" and for "Clean Coal and Energy Projects." The former provides tax credits, spread over 10 years, equal to the sum of the first $500 million of investments in the facility, plus 5 percent of any investment over $500 million. The second program offers financial incentives for selected facilities that will reduce air emissions, and use clan coal technology that are primarily burning Illinois Basin coal or coal gases.

- **North Dakota**

  Investments in new power plant construction, repowering, or environmental upgrades may be eligible for an exemption from the State's 5 percent sales and use tax. Plant can also receive an exemption from 85% of the state's installed capacity tax (and possibly an exemption from the remaining 15% levied by the local governments).

- **Pennsylvania**

  Through its Alternative Energy Portfolio Standard Act, the State requires electric distribution companies and electric generation suppliers to provide a percentage of their electricity from alternative energy sources. These sources—classified into tiers that include integrated coal gasification combined cycle ("IGCC")—are expected to provide 10% within 15 years. Further, the Governor is currently proposing an initiative that creates incentives for IGCC projects that encompass encouragement of long term contracting for their output and subject the output to preferential cost-recovery provisions. Additionally, the State is negotiating with the Environmental Protection Agency ("EPA") to allow older facilities to continue using coal without updated air pollution controls if the utility agrees to replace the plant with an IGCC facility by 2013.

- **Texas**

  The Texas legislature provided grant funds for clean-coal and gasification projects and additional support in relation to the identification of sites and the permitting process

- **Virginia**

  The state allows "clean coal projects" priority in the processing of permits and applications to the state air pollution authorities. It is noteworthy that Virginia defines "clean coal projects" as "any project that uses any technology, including technologies applied at the pre-combustion, combustion, or post-combustion stage, at a new or existing facility that achieve significant reductions in air emissions."

  In 2004 Virginia introduced new legislation providing for the recovery of costs incurred in the construction of coal powered generation, whereby the use of Virginia coal in a new facility designed to meet "default" load requirements within the state, is deemed to be in the "public interest." Default load requirements are for those customers who do not opt to take their power from a competitive service provider.

A further law passed in 2007 allows the State Corporation Commission (the regulator) to grant an extra return on investment of 1% for conventional coal burning plant and 2% for a cleaner coal plant with the later possibility of carbon capture.

At present Dominion Virginia Power, the state's largest utility company, has submitted plans for a $1.8bn investment, with plans to use the additional profit (c$6m) for research on coal technology. However, the plans have not yet been approved and it is as yet uncertain whether the regulatory commission will approve the extra return and its recovery in rates charged to "default" customers.

- **West Virginia**

  The Public Service Commission has the authority to authorize recovery of the costs incurred in clean coal technologies through tariffs.

- ***Renewable Plant Incentives***

  - **California**

    Examples of incentive based programs for renewable electricity production are demonstrated by the two programs of Southern California Edison ("SCE") and the Supplemental Energy Payments ("SEPs"), as follows:

    SCE – Biomass Standard Contract: SCE offers a production incentive to customers who generate electricity with eligible biomass-energy systems, including landfill gas, municipal solid waste, wood and wood waste, fuel cells, digester gas, and sewer gas. Separate contracts are available depending on the size of the project and the generator is able to select a term of 10, 15 or 20 years. The production incentive payment varies from $80.80 per megawatt-hour (MWh) to $93.93 per MWh, depending on the term length and year of production.

    Supplemental Energy Payments: SEPs are available to eligible renewable generators for the above-market costs of eligible procurement by California's retail sellers, to fulfill their Renewables Portfolio Standard ("RPS") obligations. SEPs are only available to facilities that have been certified by the California Energy Commission as eligible for the RPS and SEPs. As of August 2007, total funding available for these payments is approximately $734 million).

  - **Texas**

    Incentives in the State of Texas are indirect and take the form of propriety and franchise tax exemptions, in addition to an array of utility rebate programs aiming at encouraging installation of solar and more energy efficient infrastructure (e.g. energy standards for public buildings).

Unlike California, Texas' renewables portfolio standards take a defined quantitative approach to reach a given output level from the specified technologies. In 1999 the Public Utility Commission adopted rules for the state's Renewable Energy Mandate, establishing a renewable portfolio standard ("RPS") a renewable-energy credit ("REC") trading program, and renewable-energy purchase requirements for competitive retailers in Texas. The 1999 standard called for 2,000 megawatts (MW) of new renewables to be installed in Texas by 2009, in addition to the 880 MW of existing renewables generation at the time. In August 2005, Senate Bill 20 increased the renewable-energy mandate to 5,880 MW by 2015 (about 5% of the state's electricity demand) including a target of 500 MW of renewable-energy capacity from resources other than wind.

- **New York**

The New York Incentives for renewable energy include production incentives, property tax exemption, renewable portfolio standards and renewables-specific interconnection standards, as follows:

Production incentives: The Anaerobic Digestion program provides $500/kW capacity incentive for new equipment and $0.10/kWh production payment for new systems or $0.02/kWh maintenance payment on production from systems installed or substantially upgraded since Jan. 1, 2003. The maximum incentive is $1 million.

Property tax exemption: the New York State Real Property Tax Law provides a 15-year real property tax exemption for solar and wind energy systems constructed in New York State. In September 2002, the property tax exemption was expanded to include farm-waste energy systems.

Renewable portfolio standards: the New York Public Service Commission (PSC) adopted a renewable portfolio standard ("RPS") in September 2004 and issued implementation rules in April 2005. New York's RPS has a target of 25% by 2013. Of this, approximately 19.3% of the target will be derived from existing (2004) renewable energy facilities and one percent (1%) of the target is expected to be met through voluntary green power sales. The remainder will derive from new, eligible resources centrally procured by the New York State Energy Research and Development Authority (NYSERDA).

Market Framework

Wholesale markets in the USA generally operate on the basis of pool based frameworks, which ensure that generation is despatched on the basis of the least cost bids that would meet the system operator's projected demand. Generators are paid for their output on the basis of payments made by the pool and on the basis of additional contracts made with suppliers/retailers (contracts for differences).

Renewable resources, including hydroelectric generation, currently supply about 9% of the electric energy provided by North America's Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).[9] In addition to assisting in compliance with the "renewable portfolio standards" (whenever the ISOs and RTOs are mandated to plan for sufficient resources), the overall strategy to encourage additional renewable resources includes the following four features:

- facilitate access to large, organized markets in ISO and RTO regions to all those interested in investing and building new power plants;
- ensure price transparency of these markets to ensure that developers know the value of their power, making investment decisions easier;
- facilitate the dispatch of renewable resources and reduce the cost of their integration in the power system; and
- increase the coordination of regional transmission planning to ensure that the transmission upgrades necessary to bring renewable energy to market are added in timely and orderly manners.

The capacity margin in the US varies considerably from state to state. The development of effective wholesale markets and an increased focus on regional markets and regional technical and interconnection standards are presently being pursued in an attempt to help prevent a repeat of the California power crisis.

Purchasing and Pricing

The main wholesale markets in the USA are market based pooling systems, with prices bid by generators and despatch on the basis of the most cost efficient stack of generator bids needed to satisfy demand. As such generator prices are set by competition rather than regulation and a generator's decision to undertaken rehabilitation and modernisation would therefore reflect his forward projections of revenue available from the market and his expectation of despatch based on estimated future running costs.

Retail market contestability varies considerably from state to state, though the USA is generally behind Western Europe in terms of progress with market liberalisation. Hence, regulators still, in many cases, exert considerable influence over the suppliers/retailers' ability to pass on the costs of their energy wholesale purchases to their customers.

A few specific aspects of the energy purchasing framework in the US are however worthy of specific comment.

Renewables Portfolio Standards in around 25 states (including California) require retail sellers of electricity to increase their sales of eligible renewable-energy resources by a given percentage (at least 1 percent per year in California) in order

[9] ISOs and RTOs are the organizations that operate the power grid and the electricity markets for two-thirds of the electricity demand in the U.S. and just over 40% in Canada. As of 2007, the North American ISOs and RTOs include the Alberta Electric System Operator (AESO), California Independent System Operator Corporation (CAISO), Electric Reliability Council of Texas (ERCOT), Ontario's Independent Electricity System Operator (IESO), ISO New England, Inc. (ISO-NE), Midwest Independent Transmission System Operator, Inc. (MISO), New York Independent System Operator (NYISO), New Brunswick System Operator (NBSO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool (SPP).

to achieve pre-determined standards for the percentage of end user sales to be derived from renewables sources.

Similarly, the portfolio standards applicable in Austin, Texas and set by order of the City Council, requires that the local utility (Austin Energy) procures 5% of its needs from solar thermal electric, photovoltaic, landfill gas, wind, biomass, hydroelectric, geothermal electric, tidal Energy wave Energy. This is set to increase to 30% by 2020.

As mentioned above, in relation to the output of power from a clean coal power project, the State of Colorado adopted legislation in 2006 that ensures that the regulator (Colorado Public Utilities Commission) shall approve power purchase agreements that utilities shall enter into with clean coal power generators and ensure the recover of such costs in tariffs.

South Africa

Industry structure and broad policy framework

South Africa is one of the four cheapest electricity producers in the world and almost 90 percent of its electricity is generated in coal-fired power stations. Koeberg, a large nuclear station near Cape Town, provides about 5 percent of capacity. A further 5 percent is provided by hydroelectric and pumped storage schemes. It is a member of the Southern African Power Pool, a power trading arrangement between 12 southern African countries.

The electricity sector is regulated by NERSA, the South African Energy Regulator. NERSA was established by the National Energy Regulator Act of 2004 and the Electricity Regulation Act of 2006. It undertakes the function of gas regulator, petroleum pipelines regulator, and electricity regulator.

Eskom dominates the upstream sector, being an integrated generation and transmission company. In global terms, Eskom is among the top seven in generating capacity, among the top nine in terms of sales. It generates around 96% of the country's electricity needs.

Recent government announcements suggest Eskom will become the single buyer in the South African wholesale electricity market. At present Eskom is the only South African utility able to participate in the Southern African Power Pool.

Eskom sets its customer tariffs annually, based on forecast demand and an overall portfolio of generation. While generation dispatch in real time is based on an economic merit order of available generation capacity there is no spot market. Eskom's annual tariffs are approved by NERSA, the South African Energy Regulator.

Due to higher than expected demand growth, South Africa is witnessing a significant reduction in its reserve margin in the power sector. Indeed, as this report is being written, South Africa is experiencing significant power outages, which are creating some turmoil in the country. The SA Government's response to this situation (published in January 2008) and summarised below, includes a range of measures to improve the supply demand balance in the immediate and longer term, including price increases necessary to support new build, but energy efficiency measures at Eskom's power stations are not a significant part of this response.

In 1998 the Government published a White Paper on the Energy Policy of the Republic of South Africa (Energy White Paper). A major focus of this paper was the desire to restructure the distribution sector, which in South Africa is very diverse and owned by local municipalities, a situation that appears to result in subsidisation by the municipally owned electricity businesses.

The White Paper was written at a time of abundant energy resources in South Africa and when expectations for demand growth were reasonably modest. However actual demand growth in the intervening period has been much higher than expected, reducing the reserve margin in the South African power sector to very low levels. Indeed, as already mentioned, South Africa has been experiencing significant power outages since December 2007. These outages are currently ongoing and are causing significant political problems.

According to an article in African Energy (Issue 118 - 13 July 2007) the national electricity reserve margin in South Africa fell from 25% in 2001, to 6% in 2007, due to a lack of investment, combined with strong demand growth. The same article also stated that NERSA is believed to consider a margin of 15-19% as realistically adequate, in line with international norms for a largish system. At the same time capacity margins are also diminishing throughout southern Africa, limiting the opportunities to import power through the Southern African Power Pool.

During the last few months there have been rolling black-outs and interruptions of supply to large customers, including mines, severely disrupting South Africa's economy.

A review of the Government's energy policy was commenced at the end of September 2007, to be completed by the end of 2008. The project will review the 1998 White Paper, in the light of changes that have occurred since that document was published. These changes include significant increases in the price of oil and a reduction in the national electricity reserve margin, with resulting increases in brown outs and black outs. The review will identify gaps in the present policy and, if need be, set new objectives.

It would appear that the focus of government policy, regarding electricity generation, will be on investing in new capacity and on demand side measures in order to meet demand and improve reserve margins. Apart from the economic dispatch of the merit order, in which cheaper generation will be dispatched first, there do not appear to be any direct policy mechanisms to encourage the more efficient operation of existing plant.

The fundamental indicators suggest significant investment in generation capacity in South Africa is required and the political environment would seem to support such investment. The issue is who is in a position to fund the large investment program required. The options are increased tariffs, or an equity injection from the shareholder to allow Eskom to undertake the investment, the encouragement of Independent Power Producers (IPPs), the selling of some of Eskom's assets to fund new investment, or a combination of the three.

The Government has already announced that it intends 30% of new installed generation capacity to be built by IPPs. However the regulatory environment in the Electricity Supply Industry is currently undergoing development and therefore presents a number of additional uncertainties. It can also be assumed that the recently announced review of the Government's energy policy will re-examine the options for financing new investment, as well as the target for IPP participation.

- ***Government response to crisis***

  In January 2008 the South African Government produced a "national response" to the electricity shortages indicating that the shortages were a result of "significant levels of growth" in demand, especially during peak periods.

The document indicated that price levels would have to rise considerably in order to bridge the supply-demand gap but that existing price levels were very low and that prices following necessary rises would still be competitive with other countries.

The document indicated the need for a target minimum reserve margin of 15% and stated that during the week of 14 January, for example, 5,000MW of plant was unavailable as a result of unplanned outage caused by:

- Boiler tube leaks;
- Small equipment failure;
- Output reductions resulting from poor coal quality; and
- Problems with coal supply.

A further 3,700MW was unavailable as a result of planned outages.
The document concludes that in the short-term (2008/9) a further 3,000MW of capacity is needed to create "breathing space" and this is to be achieved through: return to service of 1920MW of mothballed plant;

- completion of a little over 1,000MW of open cycle gas fired plant;
- completion of 500MW of co-generation plant; and
- upgrade of an existing coal fired plant, creating an additional 120MW of capacity. No other energy efficiency measures are planned.

In the longer term (2010-2015) the document identifies:

- the return to service of a further 605MW of coal fired plant:
- 8,000MW of new coal fired plant,
- 1,332MW of pumped storage plant,
- 3,500MW of co-generation plant,
- a further 1,000MW open cycle gas turbine plant;
- 100MW of wind powered capacity; and
- a further 30MW of upgraded coal fired plant.

Beyond that the SA Government's response to the electricity shortages facing the country at a time of excess demand placed a very strong emphasis on the need for demand side measures through a power conservation programme designed to induce behavioural change in customers and to end the shortage situation within a period of 3 years, with only limited use of energy efficient upgrades and no arrangements in relation to the costs of planned and unplanned outages.

The response includes a major programme designed to enhance the use of compact fluorescent lightbulbs, which it is estimated could save up to 750MW by 2010 and a solar water heating programme designed to save 650MW over the next 3 years, as well as a range of loner term measures.

It is notable that the document does not make significant mention of enhanced operating efficiencies at the existing power station fleet.

Controls and incentives

With regard to emissions controls and incentives IPA was unable to get any firm information from NERSA. It is our understanding that new power stations will be fitted with fgd equipment, though whether this will be a specific requirement of IPPs or a policy on behalf of ESKOM is at present unclear. Existing stations do not appear to be governed by strict emissions related legislation and there do not appear to be any specific incentives to enhance operating efficiency.

Currently only 1.2%, or 865MW, of South Africa's electricity comes from renewable sources. The South African Department of Minerals and Energy (DME) has subsidised two renewable energy projects to date, with a combined capacity of 8MW.

However, a Subsidy and Finance Office for Renewable Energy has recently been established in the DME and this department is working on the establishment of a Tradable Renewable Energy Certification System, which will provide an additional revenue stream for the development and support of renewable energy projects. The system is expected to be operational later in the year.

The Government has a partnership with the Global Environment Facility, to fund projects and programmes that protect the environment, to provide technical assistance to renewable energy project developers, and leverage investment from the private sector. As yet however little is known about the proposed subsidy mechanisms.

Market framework

There is no free market for electricity in South Africa. A move towards a 'multi-market model' was being considered in 2003 and 2004. This model would entail moving towards bilateral trading between entities, with over the counter or exchange based trading in addition and a balancing market to match system needs and ensure fair "cash out" of supplier under or over deliveries.

The Government's emphasis has since shifted away from implementing such a model, with greater emphasis now placed on establishing new capacity, to meet the projected (and now actual) shortages, rather than on the efficiency of the market.

At a meeting on 5 September 2007, the Cabinet decided that Eskom be designated as the single buyer of power from IPPs in South Africa. The same meeting stated that it is a Government ambition that over the next 20 years IPPs will build more than 50% of all new non-nuclear power plants in South Africa.

In the proposed model, Eskom will buy all energy that IPPs produce and then sell this power to the Regional Electricity Distributors.

Eskom has been given this designation due to the fact it has already set up an internal power pool. Six different generation groups of Eskom already offer power into this pool. It is envisaged that the pool would be expanded to include the output of IPPs. Currently only an Eskom entity can trade on the internal pool. This means an IPP would sell its output to Eskom under a Power Purchase

Agreement and would receive the price stipulated in the PPA, providing revenue stability for the investor and hopefully encouraging them to make new investments.

The main mechanisms for ensuring efficiency in investment are the requirement to gain a generation license and that the license must be consistent with a centralised 'integrated resource plan' drawn up by NERSA. The main mechanism for ensuring efficiency in operation of plant is the regulation of customer tariffs by NERSA (including the prices at which an IPP sells its output) and the fact Eskom dispatches plant according to an economic merit order.

- ***Generation Licence***

  Generation as an activity requires a licence from NERSA. In general, rehabilitation and modernisation of existing plant that does not add significant capacity and is aimed at extending the life of the plant, does not require an additional licence. Before undertaking such a programme of works the plant managers would need to seek approval that the programme of works was in accordance with the approved integrated resource plan and would enhance the plant's position in the ESKOM merit order. Integrated resource plans are discussed in more detail below.

  The standard generation licence sets out that the tariff at which a generator will sell its output. In effect, NERSA approves Eskom's bulk supply tariff which it charges to distributors and to end use customers. The calculation of this tariff is based, among other things, on the whole portfolio of generation available to Eskom. That is, regulation occurs at Eskom's sell price, rather than at the price which it buys generation from individual plant. In the case of IPP's, the Power Purchase Agreement should also be included in the licence application, including information regarding the sale price of the IPP's output. Thus IPP output prices are indirectly, rather than directly regulated and there are no controls on non-price matters, such as anticipated efficiency, only on price.

  There is no restriction on a municipality refurbishing existing plant (although municipality ownership of coal fired plant is not common. At present, municipalities that own generation sell it to their own distribution connected customers and reduce their central requirement from ESKOM.

  In order to recover the costs of a rehabilitation and modernisation programme the municipality must submit the anticipated costs as part of its overall revenue requirement to NERSA, who will then consider whether the costs are reasonable, by comparison with the costs of purchasing from ESKOM. In the future this will take account of the costs of likely IPP projects. Because of the unfortunate situation in South Africa at the moment and because the market structure is under review, we were unable to discover the precise details of the NERSA methodology for assessing the municipal generator's reasonable costs.

  In the case of an IPP, a licence will need to be obtained from NERSA. The licensee must show that the proposed generation project is compliant with the integrated resource plan. We assume this to mean that the cost structure of the proposed generation project must be consistent with the integrated resource plan and that the proposed generation will have a place in the generation merit order implicit in this plan.

In the case of an IPP, the Power Purchase Agreement under which it is selling its output must form part of the application for a licence. This effectively means the prices at which an IPP sells its output under a PPA will need to be approved by NERSA. Inherent in this process is that NERSA will approve the rate of return the IPP receives. This is consistent with the Statement of the Cabinet meeting of 5 September 2005, that NERSA will approve all commercial agreements between the single buyer and the private producers. Cabinet spokesman Themba Maseko has been quoted as saying, when discussing the Statement of 5 September, that 'as [private] investors come in [to the market], issues of profitability will be looked at.'

During the licensing process, for security of supply reasons NERSA will also be interested in fuel supply agreements, the details of which need to be included as part of an application for a licence, among other things. NERSA will want to see that either Eskom or an IPP has a fuel supply agreement for the duration of the life of the plant or the Power Purchase Agreement (PPA).

- ***Integrated Resource Plans:***

The Electricity Regulation Act 2006 requires that projects applying for a generation licence must provide 'evidence of compliance with any integrated resource plan applicable at that point in time or provide reasons for any deviation for the approval of the Minister …'

Compliance with the integrated resource plan is to ensure the option to build new generation plant – or to refurbish existing plant – is economically reasonable when assessed against alternatives in a wider analysis of the industry. Two IPP projects have been tendered for by the Department of Minerals and Energy. It is assumed these projects were selected from those identified in the integrated resource plans. Although there is a strong central planning element to these plans, it is also assumed that proponents can propose a new generation development and have that development assessed against the integrated resource plan, in order to determine whether the new plant will gain a licence. This assumption is consistent with the Government's focus on incentivising private capital to invest in generation capacity.

It is clear from the 1998 Energy White Paper, that the Government intends that integrated resource plans should be utilised when making decisions on new investment, to ensure that only efficient options are pursued and the licensing process is one way of ensuring investments are consistent with such plans. Indeed, the Electricity Regulation Act stipulates that an application for a licence must include 'evidence of compliance with any integrated resource plan applicable at that point in time …'

The 1998 Energy White Paper identified the use of integrated resource planning when evaluating further electricity supply investments and decommissioning older power plant. This is a decision-making process concerned with the acquisition of least cost energy resources. The process is intended to 'ensure utilities avoid or delay electricity supply investments, or delay decommissioning decisions when it is economical to do so, by optimising the utilisation of existing capacity and increasing the efficiency of energy supply and consumption.' We assume industry participants can make the decision whether or not to build new plant, and that decision is assessed against the relevant plan.

There are currently a number of plans being developed by different entities in the Electricity Supply Industry. Eskom develops the 'Integrated Strategic Electricity Plan'. This covers both a plan for generation and a plan for transmission. These two plans are developed by different divisions within Eskom, however the processes are run in parallel to ensure they are consistent.

NERSA develops the 'National Integrated Resource Plan', which deals only with generation. The third such plan is currently being developed. It is against this plan the new applications for a generation licence are assessed

The Department of Minerals and Energy produces an overarching energy plan, which includes all energy types such as coal, gas and oil, as well as electricity.

The Cabinet meeting announcement of 5 September 2007 states that the 'Department of Minerals and Energy will develop an Integrated Resource Plan that will define the magnitude of power generating capacity needed to meet the country's electricity demands.

The development of these plans and how they interact with each other is currently being reviewed. The review may lead to changes to the current regime.

Purchasing and Pricing

As mentioned above, there is no freely traded market in the South African electricity sector, either in the short term or the longer term.

The price at which generators (Eskom and IPP's) and distributors can sell to customers is regulated by NERSA. Tariffs are set annually.

As outlined in the section above there is a significant need for further investment in generation plant in South Africa, to meet increasing load growth. This will impact on the tariffs Eskom charges its customers and already Eskom has asked for an adjustment to its current Multi Year Price Determination (MYPD) to reflect this higher level of investment.

Eskom recently proposed to NERSA an adjustment to the last of three years under its Multi Year Price Determination, being an increase in prices of 18.7% for the year 2008/2009. NERSA counterproposals suggest an increase for this year of between 8.06% and 14.2%. The drivers behind these proposed increases – being increasing demand, increasing capital cost in the face of world-wide demand for new generation plant and increased volatility in coal prices – are set to continue into the next MYPD. Increases in the Eskom tariffs to distributors may act as an incentive to encourage embedded generation and demand side management. However new embedded generation is likely to face the same cost drivers and uncertainties as those experienced by Eskom.

Reserve capacity

As mentioned above the Government has accepted that South Africa should have a target reserve margin of 15%. This will be secured primarily through new build, through return to service of old coal fired plant and through demand side measures, as described above.

The SA Government intends that Eskom should act as a single buyer of wholesale power and Eskom will therefore have the responsibility for securing the necessary capacity is procured using a form of "competition in the market." These costs will be included in distributors' power purchasing costs, to the extent this is permitted by NERSA. At present it is not clear what additional incentives (if any) might be available to secure the capacity that South Africa needs.

Summary and Conclusions

The analysis of the Australian, UK, South African and US markets, set out in the preceeding four sections of this Annex and the additional summaries of four more OECD markets set out later in this Annex, demonstrate that:

- there is very little global experience with incentivisation of R&M works at old coal fired power stations, although there is a scheme in operation in Virginia to incentivise new coal fired generating capacity where such plant would use locally produced coal;
- there is a scheme of climate change agreements in the UK that can act to incentivise energy efficient rehabilitation of existing plant owned by major industrial consumers, but the scheme focuses on the measurement of emissions reductions, rather than efficiency gains and does not therefore contain any form of efficiency target, focussing instead on output measures;
- there are some interesting lessons from global best practice in setting efficiency targets and in designing incentive based mechanisms for investment in energy networks, including explicit judgements about the level of benefit sharing. These schemes demonstrate the importance of an accurate understanding of baseline operating efficiency and of standardised output measurement.
- there are some interesting precedents (for example in the UK and Australia) in terms of mechanisms to ensure the security of supply using market based mechanisms that either explicitly or through market bidding place a value on the reserve capacity required to guarantee continuity of supply, in the public interest;
- there is very little global best practice experience of incentivising R&M works in a situation of a shortage of capacity and where a large number of consumers have real difficulty in paying their bills. There is some experience of capacity shortage in South Africa, but the policy direction chosen to resolve this problem is focused on demand management rather than upgrading of existing capacity;
- there is almost no recent international experience in setting efficiency norms or in setting frameworks for analysing the costs and benefits of R&M schemes within a regulatory environment;
- there is a wide range of energy policy objectives and no one country appears to start from the same position or is aiming to achieve precisely the same outcome (in terms of the balance between the elements) as others;
- there is a very wide range of approaches and instruments to achieve energy policy objectives relating to a country's generation portfolio, both market based and regulatory/administrative and for both coal fired plant and renewables plant;

We have grouped the international best practice experience into the following categories:

- Regulatory incentives for generating plant, such as cost pass through allowances or an additional return on investment; and
- Regulatory incentives for network operating efficiency and network outputs.
- Market modifications and preference systems;
- Purchasing and sales related obligations and taxes;
- Direct controls on generator output;

- Direct grants; and
- Fiscal incentives;

Each of the schemes we have examined in this review of international best practice is then reviewed under one or more of these headings.

Summary of International Best Practice Schemes

Table 4 of this Annex sets out our review of almost 50 energy policy instruments described in the preceeding sections of this Annex.

Annex 8, Table 5 – review of generation policy instruments

Type of policy instrument & country	Description of policy instrument	Comment
Regulatory incentives for generation		
USA - Virginia	Pass through plus new build incentive- the State Corporations Commission may allow the costs of a new coal fired plant to be passed through to "default" customers as a matter in the "public interest," and can allow an additional 1% or 2% return on investment as an incentive, dependent upon the precise plans and the potential inclusion of carbon capture technology	Additional 1% is not dependent upon efficiency, but is an incentive to burn local coal. (In effect this is a distortion of the regional market). The 2% allowance depends on the potential for carbon capture.
USA - California	Pass through - preferential purchasing by Southern California Edison company (utility) dependent upon term of contract – costs may be passed through to customers	Pass through mechanisms are common but don't appear to be linked to controls on generator efficiency or generator output prices. Act as controls on supplier purchasing costs.
USA - Federal	Accelerated amortization – 7 year amortization for installation of emissions control equipment	
USA – Colorado	Pass through - exemption from certificate of public necessity and guarantee of approval to include in tariffs, to ensure cost recovery	Effectively guarantees cost recovery in market that is normally competitive
USA – West Virginia	Pass through - regulator has authority to permit recovery of clean coal costs in tariffs	Effectively guarantees cost recovery in market that is normally competitive
Regulatory incentives for networks		

Australia – general	Opex incentive - incentive to outperform Opex assumptions included in allowed revenue, with explicit judgement on benefit sharing (30:70 in favour of customers) and guaranteed period of benefit retention (5 years). Accurate understanding of baseline costs and performance also critical.	Incentive operates on opex costs. Excess gains achieved are clawed back at the end of the allowed 5 year period – network operators are thus incentivised to reveal the efficient level of their operating costs. Explicit judgement on benefit sharing and guaranteed period of retention of "excess" may be useful precedent. Baselining is critical.
UK – general	Opex incentive – incentive to outperform Opex (and Capex) assumptions in 5 year revenue control. No guaranteed period of benefit retention so investment cycle skewed with higher incentive to invest in early years of control period. Accurate assessment of baseline input critical.	System appears less sophisticated than Australian scheme in key respects, but overall principle of benefit sharing is the same. Baselining is critical.
UK – output incentive	Output quality incentive – additional incentive to achieve output performance levels in excess of trajectory/target (which is based on an assumed normal output improvement) permitting recovery of up to an additional 2% of revenue.	Innovative scheme designed to work in conjunction with general revenue incentive, similar to output incentives already in place in India. However, in the UK company targets are specific and relate to own past performance (baselining is critical and based on common and independently audited reporting systems – all companies have been able to meet targets set so far.
Market modifications		
Alberta (Canada)	Net settlement instruction – allows renewable generators to set up contracts outside of the pool and to guarantee long term stable cash flow. If generator cannot run "top-up" is provided at pool prices	Top up is at market price
Australia – security of supply	National Electricity Market Management Company (NEMMCO) responsible for securing the capacity necessary to ensure an adequate system capacity margin (in the public interest) with costs effectively socialized.	Because costs are socialised it can be argued that NEMMCO has little incentive to procure reserve power effectively, though the obligation to procure from the market at the best possible price is designed to reduce this concern. The system may also dampen investment

		signals.
UK – security of supply	Explicit capacity payment - UK wholesale market used to include an explicit capacity payment as an incentive to new build or to maintenance of availability levels at existing plant. This included specific assessment of the "value of lost load" and the "loss of load probability."	Unfortunately the value of lost load could be argued to have been based on an arbitrary figure derived from political fear of lost load rather than any real valuation placed on lost load by customers. Similarly, the calculation of the loss of load probability is believed to have placed too high a probability on the "disappearance" of existing plant. Thus, the system was discredited because the regulator thought the capacity payments were too high. It preferred to put the obligation to supply on suppliers and allow then to explore the value that customers placed on lost load in a commercial and competitive context.
Purchasing/ sales obligations & sales taxes		
GB renewables obligation	Purchasing obligation - obligation to buy output of renewables "certificated" plant to match specified % of supply. Combined with traded market for certificates. Obligation now 7.9% increasing to 20% by 2020.	Obligation and certification systems provide no guarantees of future value of certificate or against political risk in relation to the level of the obligation. Purchasing obligations are not used to support efficiency in coal fired plant.
UK Climate change levy	Tax on sales - of electricity that can be (partially) offset by investment in renewable generation sources	
UK Climate change agreements	Reduction in sales tax - if certain emissions reduction targets are met by industrial companies	There is some evidence that companies have invested in enhanced efficiency technologies but the targets are reduced emissions rather than enhanced efficiency levels.

USA - Pennsylvania	Purchasing obligation - Distribution companies must purchase specified % of requirement from alternative generation sources (includes IGCC)	
USA - California	Purchasing obligation - Renewables Portfolio Standard (RPS) obligation based on specified % of demand purchased from projects certified by regulator	
USA – Texas	Purchasing obligation - RPS obligation set by City of Austin for its own local supplier with a target level of 5% by 2015	
USA – New York	Purchasing obligation - RPS obligation based on target of 25% by 2013	
South Africa	Purchasing obligation - Working on development of REC/RPS scheme	
Italy	Feed-in tariff and purchasing obligation - certificate and quota system. Renewables generators can take advantage of "feed-in" tariff whereby quota of electricity (3.05% for 2007) is purchased by grid operator and charges are socialised.	Quota systems/feed in tariffs can give long term purchasing certainty to generators
Netherlands	Feed in tariffs – system operator guarantees fixed fee per KWh, guaranteed for 10 years, but to cover only those costs not covered by market price.	
Netherlands – and rest of European Union	Statement of origin - suppliers obliged to publish statement of origin, stating what sources their supplied power is derived from	Not clear that this scheme is actually incentivising customer behaviour
Germany	Feed in tariffs - with target of 12.5% by 2010 (already >9% by 2006) and 20% by 2020. Gives constant fee over 20 years. Level of tariff adjusted for different technologies. Adjustments may be made annually to achieve right overall result but existing contracts enjoy grand-father rights. Low cost producers get lowest prices in order to encourage development of marginal sites.	

Alberta (Canada)	<u>Purchasing preference</u> - 90% of state's own power use is sourced from renewable sources – form of purchasing preference	
Alberta (Canada)	<u>Purchasing obligation</u> - RECs system now introduced	
Direct grants		
Australia	<u>Demonstration funding</u> - pump priming support for low emissions technologies at demonstration stage – e.g. carbon capture and storage (ccs).	Demonstration funding and direct funding have limited merit if scale of problem is large
Australia	<u>Demonstration funding</u> - Greenhouse Gas Abatement Program. Support for demonstration projects. Includes Liddell power station efficiency enhancement project	
Australia	<u>Demonstration funding</u> - COAL 21 demonstration project to create near zero emissions coal fired generation capacity	
UK	<u>Demonstration funding</u> – grants aimed at nascent technologies, e.g. offshore wind, tidal power and marine power	
USA	<u>Demonstration funding</u> – CCPI program. Support to clean coal projects, including existing plant, must be able to demonstrate efficiency improvements.	
USA	<u>Emissions reductions</u> - Clean Air Coal Program provides grant funding to upgrade of existing plant by retrofitting pollution control equipment	
USA	<u>Loan guarantees</u> - Carbon capture R&D programme provides incentives for innovative technologies including loan guarantees	
USA - Alaska	<u>Initial capitalisation</u> – Bond financing support to clean coal projects from	

	the industrial development authority. Bonds must be repaid	
USA – Illinois	Capital grant – support towards costs of buildings, structures and durable equipment for new IGCC facilities	
USA – Texas	Capital grants – available to IGCC projects	
South Africa	Capital grant – Department of Minerals and Energy has grant aided 2 renewables projects	
Germany	Direct support - > €200m annual funding under market incentive programme for commercialisation and deployment of renewables projects	Large and successful funding programme – but expensive
Germany	Capital grants and loans – available from KfW for renewable energy scheme installation at below market interest rates for 10-20 years, with redemption free initial period.	
Indirect fiscal incentives		
USA	Tax credits – credits available for IGCC and "advanced combustion facilities"	Tax credits and exemptions are used to incentivise efficiency in coal fired plant but should be equal treatment between new and existing plant or market distortion may result
USA	Accelerated amortization – 7 year amortization period permitted for air pollution control facilities	
USA	Tax credit – volumetric Federal tax credit for renewable electricity production at current rate of US$0.015 per KWh.	
USA	Tax credit – State and local governments can issue "clean renewable energy bonds" ("CREBs") to finance renewable energy and certain clean	

	coal facilities. CREBs are a new form of tax credit bond in which interest on the bond is paid in the form of federal tax credits by the Federal Government, in lieu of interest paid by the issuers.	
USA – Illinois	Tax exemption – for building material and equipment for new and expanded coal fired plant	
USA – Indiana	Tax credit – for IGCC facilities burning local coal	
USA – North Dakota	Tax exemption - investments in new power plant construction, repowering or environmental upgrades may be eligible for an exemption from the State's 5 percent sales and use tax. Plant can also receive an exemption from 85% of the state's installed capacity tax.	
USA – Texas	Tax exemption – from propriety and franchise taxes available for solar and other energy efficient installations	
USA – New York	Tax exemption - 15-year real property tax exemption for solar, wind and farm-waste energy systems constructed in New York State.	
Direct output controls		
Australia	OSCAR – national system for reporting emissions abatement actions	Emphasises the importance of an agreed and consistent reporting system
Australia	Greenhouse Efficiency Standards – 42% voluntary target for black coal plant implemented through legally binding agreement	It is not clear that the scheme has been successful
UK, Netherlands, Italy, Germany	Emissions limits – enforced by Environment Agency (UK) – compliance with EC Large Combustion Plant Directive & EC emissions trading scheme	Emissions limits provide an incentive to greater efficiency but may impact availability and load factor

Alberta (Canada)	<u>Emissions reduction limits</u> – 12% reduction required for all who emit >100,000 tonnes greenhouse gases – first scheme in North America
Other	
Germany, UK and other European countries	Priority and/or subsidised connection to network for renewables plant
USA – Texas	Support with permitting and identification of sites
USA – Virginia	Priority in processing permits from air pollution authorities for clean coal plants. Includes existing facilities where significant reductions in emissions can be achieved

As Table 4 (above) shows there is very little worldwide experience in using the regulatory regime to incentivise specific generation policy objectives. Rather these tend to be incentivised through purchasing obligations, direct grants (especially for demonstration projects) and indirect fiscal adjustments, with the latter more common in the USA rather than Europe. Only in the USA have direct regulatory incentives been used for coal fired generating plant,

It is also notable that purchasing obligations have not been used to incentivise the development of clean coal technologies or efficiency enhancements, which tend to rely on demonstration funding and, to some extent, tax credits.

However, there are some useful conclusions that may be drawn from the international experience summarised in relation to regulatory incentivises in general and these are summarised below:

- ***An accurate baseline***

  In both Australia and the UK (as well as in most other regimes that use regulatory incentive mechanisms, primarily to encourage companies to reveal the efficient level of operating costs for transmission and distribution networks, it is critical that a clear and accurate baseline is established from which to measure present cost levels and future efficiency savings.

  A variety of mechanisms is used to establish the baseline including audited regulatory accounts, audited performance (output) reporting systems (which may or may not also be separately incentivised) opex reductions, price control questionnaires (using the same base year) and asset management plans.

  As described in Annex 4, the establishment of a trusted baseline is a critical issue in relation to setting norms and targets for measuring efficiency improvements in India and it would be useful if the CERC guidance on R&M projects specifically addresses this issue..

- ***Explicit and transparent judgement on benefit sharing and retention***

  The Australian system of network regulation includes an explicit judgement on the appropriate level of benefit sharing and on the appropriate period over which the incentive should apply and is somewhat more sophisticated than the GB system in this respect. We consider that this is a useful precedent for India and will support moves already made by some regulators to allow a reasonable period in which the incentive should operate, for example for the length of a 7 year multi-year tariff order.

  Again, it may be useful for the CERC to specifically address this issue in its forthcoming guidance on R&M projects.

- ***Company specific performance targets***

  The UK and Australian network incentive schemes both start from the premise that the individual circumstances of each network operator require a separate starting point, or baseline in terms of allowed opex costs. Regulators then assume a certain, “normal” performance target that is relatively easily achievable but for which no incentive is given, with incentives earned by companies in relation to outperformance of the assumed normal efficiency gain. The principle is that the companies are incentivised to reveal the true level of efficient operating costs and that outperformance reveals this to the regulatory authorities.

This system is a little different from the system operating in India, where generators are expected to achieve "normative" efficiency levels and receive no incentive unless they do so, no matter what the baseline starting position of the plant that they own.

- ***Electricity purchasing and the public interest***

  In the USA the regulatory system is used to provide that certain energy purchasing strategies, favouring for example coal fired generation, are deemed "in the public interest" and able to be "passed through" in what may be termed captive or regulated customer tariffs. This helps to guarantee cost recovery by generators and may act to reduce the cost of capital. However, it is also a potential market distortion that may lock suppliers into unfavourable purchasing arrangements and great care needs to be taken before a decision is taken to impose such "public interest" obligations on suppliers through the regulatory system, especially at a time when the market framework is emerging.

- ***Use of market mechanisms***

  Similarly, market mechanisms such as capacity payments or reserve capacity contracts may be used to ensure "public interest" concerns are taken into account. Such costs are typically socialised. However, as with the UK capacity mechanism during the old Electricity Pool, it is important to provide some form of mechanism or incentive designed to reduce such costs are far as possible. It is also necessary to beware of the potential for introducing long-term market distortions and mechanisms that rely unduly on value judgements that reflect political fear of the consequences of a loss of supply, rather than market reality and/or on highly complex calculations of the probability of insufficient supply.

Generation policy instruments in selected western countries

Netherlands

There are no special arrangements (such as priority despatch) for renewables generation in the Dutch power markets: renewable generation is treated the same as conventional generation and has to interact with and operate within the rules of the Dutch power markets.

- Traded Market: counterparties can trade power either bilaterally, through brokers or through exchanges. Non-physical players may also be involved in the traded market.
- Self despatch: Program Responsible Parties (PRPs) decide individually how much power they physically plan to inject and withdraw from the system.
- Notification: Program Responsible Parties (PRPs) have to notify their traded position and planned physical position to the system operator TenneT at a specified point in time.
- Balancing Settlement: Counterparties are incentivised to balance their physical and contractual positions. Imbalances between these positions are subject to imbalance charges. There is a different imbalance price depending on whether the counterparty is long or short (in relation to their physical and notified position).
- Balancing Market: There is a balancing market, in which counterparties can submit bids/offers to change their physical flows, allowing the system operator to balance the system in real time.
- Transmission Access & Charging: Transmission Access is normally firm and charges are levied based on reinforcement work required by the TSO. However, in certain defined regions the TSO has begun to offer non-firm access prior to full reinforcement work under the “runback scenario”.

Renewable generation gets value for its output by selling power to other market participants. Projects may elect to enter into long term off-take contracts or to trade output in the power markets. Thus, renewable generation should achieve a price related to the power market price for its output. In addition to the market value of the power produced there are support mechanisms designed to increase the value of renewable generation.

- ***Source Specific Premium Tariffs***

  In July 2003 the Environmental Quality of Electricity Production scheme (Milieukwaliteit Elektriciteits Productie or MEP scheme) was introduced to encourage investment in sustainable energy. Under the MEP scheme, Dutch producers of renewable electricity feeding into the public grid received a fixed fee per kWh for a guaranteed period of ten years. The subsidy was intended to cover only the proportion of cost that is not covered by the market price for electricity. This is distinct from a standard feed-in tariff as generators receive the variable market price for their energy, plus a fixed feed-in component. The value of the tariff differed for each type of renewable generation (the amount of subsidy for offshore wind energy was the maximum).

The subsidy is financed by all electricity consumers who pay a levy specifically for this scheme. These tariffs are adjusted annually and tradable certificates are used to claim the feed-in tariffs. A central organisation, CertiQ, issues the certificates and EnerQ (set up by the TSO TenneT) pays out their value.

In September 2006 €270 million was allocated for new small-scale renewable production projects and this was increased to €326million in total in May 2007.

In July 2007, the Ministerial Council agreed on a draft version of the "Stimulation for Sustainable Energy Generation" programme ("Ontwerpbesluit stimulering duurzame energieproductie", SDE) to replace MEP. The subsidy system will vary annually, unlike MEP and will depend on annual energy market prices (therefore representing the difference between the generation cost and market price).[10,11]

- ***Guarantees of Origin and Fuel Mix Disclosure***

  It has been mandatory for electricity suppliers to disclose their generation mix since January 2005. The fuel mix of Dutch energy suppliers is based on:

  - Own generation mix: fuel mix is known
  - Direct contract with generator: fuel mix is known
  - Purchase from third parties/traders (the APX/OTC/import market): mix is not known and country average is used, which is calculated by an independent consultant.

  This fuel mix information is provided in the form of a label to all electricity consumers.

  Rather than devise a new Renewable Energy Guarantee of Origin (REGO) system for fuel mix disclosure, exiting MEP certificates are used as most renewable and CHP plants are already accredited.

Germany

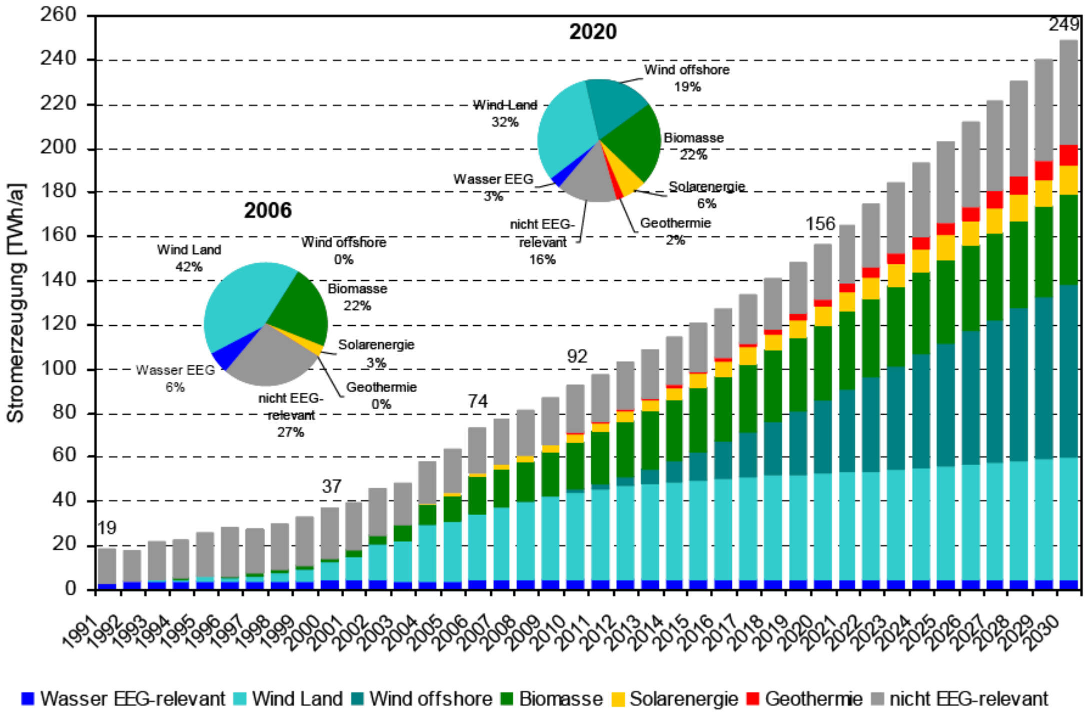
The German electricity market is the largest in Europe. Total net consumption in 2000 was 532TWh and total installed net generating capacity at the beginning of the year 2000 amounted to 116 GW (25% hard coal, 22% gas, 18% nuclear power, 18% lignite, 8% hydro power, 5% wind, 4% oil and others).

Immediately after liberalization of the energy market, eight major integrated generation companies existed that subsequently developed into four major players

[10] Where energy prices are higher, subsidies will be lower and vice versa.
http://www.minez.nl/content.jsp?objectid=152579&rid=home
[11] SenterNovem Nieuws July 19, 2007
https://www.senter.nl/mep/nieuws/Nieuwe_stimuleringsregeling_duurzame_energieproductie.asp

through a number of international and domestic mergers and acquisitions: RWE, EnBW, E.ON. and Vattenfall Europe. All these remaining generation companies are vertically integrated, but legally unbundled. The capacity share of the largest four companies increased from 42% of total German generation capacity before these mergers to 61% afterwards.

Annex 8, Figure 7 Evolution of Electricity Generation from RES until 2030[12]



- ***Support Mechanisms***

  Renewable energy sources (RES) in Germany are mainly promoted by feed-in tariffs under the Renewable Energy Sources Act (Erneuerbare Energien Gestez, or EEG) the Market Stimulation programme and a number of smaller indirectly supportive government programmes and policies. In addition, the Reconstruction Loan Corporation ("Kreditanstalt fuer Wiederaufbau", KfW) offers and manages a number of preferential loans systems and capital grant schemes for RES installation, as described below.

  - **2004 Renewable Energy Sources Act**

    The Federal Electricity Feed-In Code was replaced by the Renewable Energy Sources Act – EEG. The particular aims of the amended EEG are to increase the share of renewable energies in the total electricity supply to at least 12.5% by the year 2010 and to at least 20% by the year 2020.

    About 54% of the revenue from feed-in tariffs is captured by wind power, while 15% is allocated to PV installations. The contribution

[12] http://www.bmu.de/files/pdfs/allgemein/application/pdf/erfahrungsbericht_eeg.pdf , p.35

from private RE generators is relatively high, amounting to 45TWh of power provision in 2006.[13]

The core elements of the EEG are:

- Priority connection of installations for the generation of electricity from renewable energy and from mine gas to the general electricity supply grid
- Priority purchase and despatch of this electricity
- A consistent fee for this electricity paid by the grid operators, generally for a 20-year period, for commissioned installations. This payment is geared around the costs
- Nationwide equalisation of the electricity purchased and the corresponding fees paid.
- The fee paid for the electricity depends on the energy source and the size of the installation. The rate also depends on the date of commissioning; the later an installation begins operation, the lower the tariff (degression) [14].

This degression incentivises early construction of installations, in order to obtain the highest payment levels and is intended to discourage operators from waiting until installations become cheaper. The EEG is also designed to ensure high-quality installations, as payments are made per kWh produced and there is therefore an incentive for operators to run their installations efficiently and with as little interruption as possible.

- **Feed-In Tariff Rates**

The EEG prescribes fixed tariffs which grid operators must pay for the feed-in of electricity generated from hydro, landfill gas, sewage treatment and mine gas, biomass, geothermal, wind, and solar sources. The minimum payments (differentiated by energy source) vary depending on the size of the installation.

The tariff level is based on actual generation cost of the respective technology as illustrated in Table 5 of this Annex.

[13] Bundesministerium fuer Umwelt
[14] Degression is the percentage reduction in the tariff in upcoming years. It serves to reduce the tariff to compensate for expected future price reductions in the capital cost of the RE asset.

Annex 8, Table 6: Renumeration under the German Renewable Energy Sources Act

Technology	Size	Remuneration in 2004	Annual reduction factor for newly commissioned plants
Hydro, sewage gas, landfill gas, marsh gas	< 0.5 MW	€ 0.0767 per kWh	-
	0.5 – 5 MW	€ 0.0665 per kWh	
Biomass	< 0.5 MW	€ 0.101 per kWh	1% p.a.
	0.5 – 5 MW	€ 0.089 per kWh	
	> 5 MW	€ 0.084 per kWh	
Solar	< 5 MW	€ 0.457 per kWh	5% p.a.
Wind	No limits	€ 0.059 per 0.087 per kWh[1)]	1.5% p.a.
Geothermal	< 20 MW	€ 0.0895 per kWh	-
	> 20 MW	€ 0.0716 per kWh	

[1)] Depending on specific wind conditions on site.

Tariff rates are adjusted annually. However, in principle the guaranteed payment period is 20 calendar years (or for hydropower 15 or 30 years). The tariff for the year of commissioning remains constant for that generator, with the exception of wind energy.

In order to take account of technological developments and the economic efficiency of these developments and to optimise the use of cost reduction potential, tariffs for most technologies are digressive, as explained above.

Two different rates are paid for electricity generated by wind: for an onshore wind park, a starting fee is paid for electricity produced for the first five years after commissioning. After these first five years, a lower basic fee is applied.

It is an unusual feature that low-cost renewable energy producers are compensated at lower rates than higher-cost producers, providing strong incentives for the development and operation of renewable energy installations on lower-quality sites. The period of higher fees can be extended according to the wind conditions at the site.

Regardless of siting, the total payment period is restricted to 20 years. For offshore wind parks, starting fees are paid for 12 years. This period is extended for installations located further from the coastline and erected in deeper water.

Wind parks which could not achieve at least 60% of the reference yield at the planned location cannot claim payment under the 2004 law. For coastal sites in particular there are new incentives for so-called “re-powering”: the replacement of old, smaller installations with modern, more efficient ones. The higher starting tariffs for offshore wind parks will be paid for installations commissioned before 2010.

More wind energy is generated in the North of Germany due to higher wind speeds. To prevent regional inequality in electricity cost to consumers, the transmission grid operators undertake a nationwide equalisation of the electricity volumes purchased under the Renewable Energy Sources Act (EEG).

- **Future Support**

Germany's Renewable Energy Sources Act is reviewed every three years. Germany's Ministry for the Environment has issued a progress report in July 2007 that lays out recommendations to amend the Renewable Energy Sources Act[15]. The recommended new rules would, if adopted, significantly increase the tariffs for offshore wind energy, hydroelectricity and geothermal energy beginning in 2009. The annual degression rate for onshore wind energy, solar/PV and biomass will be reduced.[16]

- **Market Stimulation Programme**

In 1999, the German Federal Government introduced the Market Incentive Program (MAP), which offered Federal Government grants totaling €203 million in 2003 alone, for the commercialization and deployment of renewable energy systems. €30 million was also earmarked for export promotion. The German Federal Government considers MAP to be one of its most effective current renewable energy promotion programs, particularly since funds from the program may be leveraged with other government funds.

Renewable Energy Sources are not exempt from the eco-tax, where all electricity is taxed, irrespective of its generation source.

Revenues from this tax are used to finance the Market Stimulation Programme, which supports the further development of renewables technologies. This programme primarily serves the expansion of heat generation from biomass, solar power and geothermal energy.

- **Fuel Mix**

In accordance with provisions laid down by the European Union, the 2004 EEG introduces guarantees of origin for electricity from renewable energies. This promotes consumer information and protection.

The state indirectly supports the programme by purchasing green power.

[15] http://www.renewableenergyaccess.com/rea/news/story?id=49250
[16] http://www.bmu.de/files/pdfs/allgemein/application/pdf/erfahrungsbericht_eeg_en.pdf

- **Federal States Support for RES**

  In addition to Federal policies, laws and funds, the German States (Laender) provide further support for RES. Regional differences can therefore exist where technological focus and levels of financial support vary. While the most successful instruments of support at a Federal level concern the use of renewable energies for electricity generation, on a State level the promotion of renewable technologies focuses principally on heating and cooling. A majority of support is deployed to photovoltaic and biogas systems.

- **Loans and Capital Grant Schemes**

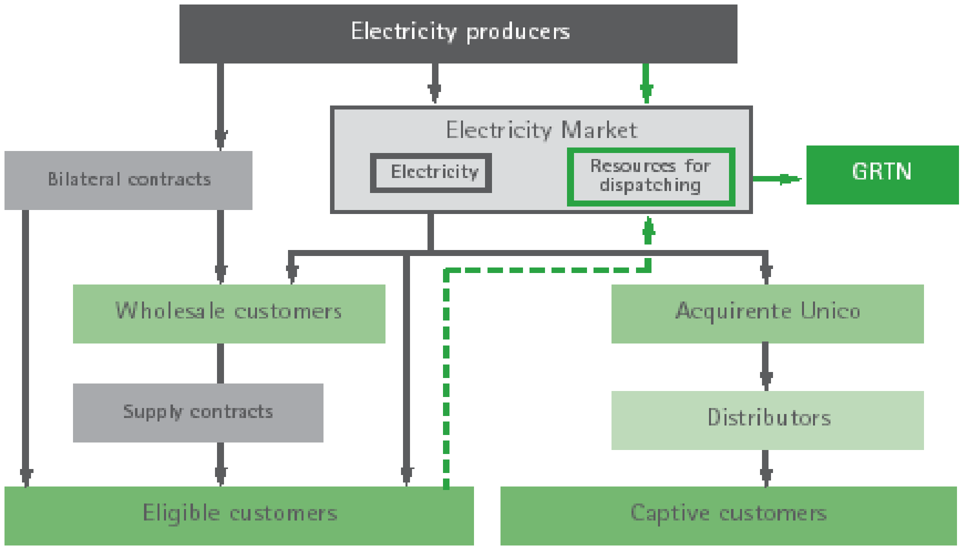
  The Kreditanstalt fuer Wiederafbau (KfW) or Reconstruction Loan Corporation offers and administers several soft loans schemes set up to indirectly support the deployment of RE technologies. Financing programmes are open to the private and public sector and focus on various technologies. Most programmes offer sub-market level interest rates with varying credit terms between ten and twenty years and a redemption-free initial phase.

Italy

In case of wind generation, producers can opt for a "regulated access" system, a form of feed=in tariff managed by the Italian system and market operator. The plant benefits from special treatment for despatch and grid transport and is paid on the basis of the average monthly price.

- Market Operator: The day ahead, adjustment and balancing electricity markets are operated by the Italian market operator, GME.
- Traded Market: Generators can enter into bilateral contracts or they can sell on the power exchanges (futures, day ahead, adjustment and balancing market). The adjustment and balancing markets are not open to renewable generators.
- Despatch: The GSE (Italian system operator) decides on despatch based on a merit order of bids into the power exchange as well as other bilateral contracts. Renewables get priority despatch.
- Notification: Price and despatch are notified by the system operator the day before real time.
- Balancing Settlement: Balancing carried out by the TSO through the despatching market (MSD). Variable generation does not participate in this market.

Annex 8, Figure 8: The Italian electricity market[17]



- ***Support Mechanisms***

  Italy currently has a certificate and quota system. This is still strongly interlinked with their former feed in tariff system, CIP 6/92.

  - **CIP 6/92**

    A good number of renewable generators still benefit from the feed-in tariffs granted by CIP Provision 6 of 29 April 1992. These tariffs are different for the various technologies and are updated every year. They are paid to designated plant for all the energy they can feed into the grid and consist of two items:

    - The avoided cost, granted over the full lifetime of the plant as a reward for avoiding production from conventional sources; and
    - The incentive, granted over the first eight years of plant operation only.

    In 2006, several wind plants were still within the eight-year term and therefore got the full feed-in tariff. In the most favourable case of plants yielding all their energy to the grid, the tariff was €149.4/MWh.

  - **Green Certificates**

    New renewable generators come under the current support scheme, which is based on a compulsory quota for electricity from RES and on tradable green certificates (TGCs). All renewable plants operational after April 1999 are eligible, this includes large hydro but from 2007 excludes new build waste to energy. This scheme was set up and regulated by Decree 79 of 16 March 1999 (restructuring the electricity market) and the subsequent Decree 387 of 29 December 2003

[17] Source: GME

(implementing EU Directive 2001/77/EC on RES promotion). Further implementation measures were then taken in 2005 and 2006.

Since 2001, the RES electricity quota obligation has been laid on operators who have produced or imported electricity from non-renewable sources exceeding 100 GWh/yr (electricity from CHP plants, auxiliary service consumption, and exports of energy are excluded from this computation). These operators must feed into the Italian grid, before the end of the subsequent year, an amount of RES electricity equalling a minimum quota of this non-renewable electricity. The RES electricity quota was originally 2% but was subsequently raised by 0.35% a year to 2.35% in 2005, 2.70% in 2006, and 3.05% in 2007.

In the past, operators knew the quota for future years (the quota was set in 2001 through to 2007). However, the industry is still waiting to be informed of the percentage quota to be applied from 2008 on.

To reduce their obligation, operators are allowed to feed imported RES-generated electricity into the Italian grid, but this energy must be certified by a Guarantee of Origin. The market price of TGCs should thus be determined on the basis of demand by obligated operators, versus supply by qualified producers. Qualified RES electricity producers get one TGC for each 50 MWh of their production, over a term that has recently been extended to twelve years. The sale of TGCs brings them income in addition to the proceeds from the sale of energy on the wholesale electricity market.

To avoid double benefit, TGCs that would be due to plants already getting CIP 6/92 feed-in tariffs are retained by GSE (Gestore dei servizi elettrici, the body managing all RES support schemes). GSE must sell them at a price fixed every year on the basis of current CIP 6/92 feed-in tariffs, among other things. Since the number of these TGCs is still fairly large, qualified renewable producers actually have to sell their own TGCs at a price close to, but obviously not greater than, the price fixed for the GSE certificates. The Italian TGC price is therefore not left to the mere interplay of supply and demand but is controlled. The price of TGCs sold by GSE has been growing steadily in the past few years. Specifically, the price of GSE's TGCs relating to 2006 RES production was fixed at €125.28/MWh.

The GSE price has kept up the TGC market price as well, thus bringing a reasonably rewarding income to investors in addition to the sale of electricity on the wholesale market. This of course holds especially for more mature RES technologies, including wind, while other technologies such as photovoltaics have had to be granted special feed-in tariffs to help fund their development.

The certificate life is 3 yrs. The operators are also guaranteed by the fact that GSE will buy back unsold certificates.

In spite of these financial conditions, which look very favourable in principle, investors have still been complaining about the way some aspects of Italy's support policies have been implemented. Particularly, they have long been complaining of delays in issuing measures regarding, for example, the fixing of electricity quotas for RES to be produced from 2008 onward, the setting of regional targets, establishing a single national procedure for plant permitting, and other actions required by Decree 387 of 29 December 2003. Some investors have even stated they would be content with lower energy and TGC prices in exchange for better-defined boundary conditions for their businesses in the long term.

Currently there is only one level of support, in a sense that all technologies are equally remunerated. Currently under discussion is a proposal of introducing a variation made by applying a different ratio in consideration to the technology maturity.

- **Photovoltaics**

On 28 Jul. 2005, jointly with the Ministry of the Environment and Land Protection, the Ministry of Productive Activities issued the Ministerial Decree referred to in Art. 7, para. 1 of Legislative Decree no. 387 of 29 Dec. 2003. The Ministerial Decree defines criteria for incentivising electricity generation by photovoltaic solar plants.

On 14 Sept. 2005, the "Autorità per l'Energia Elettrica e il Gas" (AEEG - electricity & gas regulator) adopted its Decision 188/05, which identifies GSE (the system operator) as the "implementing body" in charge of granting incentivising tariffs. On 6 Feb. 2006, the second decree on photovoltaic solar generation, extending and supplementing the Ministerial Decree of 28 Jul. 2005, was enacted. The incentive scheme applies to photovoltaic (PV) solar plants or systems (new, renovated or repowered/upgraded) which have a capacity of 1 to 1,000 kW and which have become operational after 30 Sept. 2005.

The PV projects which may be implemented and benefit from incentivising tariffs for twenty years fall under three capacity classes:

Annex 8, Table 7: Incentivising tariffs for PV

PV Plant or System	Capacity (kW)	Incentivising Tariffs (€/kWh)
Class 1	1 ≤P 1 ≤20	0.445 ("scambio sul posto", i.e. net metering) 0.460
Class 2	20 < P ≤50	0.460
Class 3	50 < P ≤1,000	0.490 (maximum value subject to bidding procedure)

The incentivising tariffs are increased by 10%, if the PV modules are used in new or renovated buildings. The incentive applies to electricity generated, measured at the output terminals of the direct current-alternating current converter.

Canada – Alberta

Alberta's electric generating capacity in 2006 was 11,497 MW. There are 280 generating units in Alberta which generated 65,300 gigawatt hours (GWh) of electricity. Coal-fired power plants (5,840 MW) generated 63 per cent of the province's electricity, while gas (4,278 MW) and hydro (869 MW) accounted for 31 and 3 per cent respectively. Wind and other generators contribute over 500 MW of capacity. Imports and exports across interties are provided with the neighbouring provinces of British Columbia and Saskatchewan.

In 2006, wind plants made up 387 MW of capacity, an increase of 363 MW since 1999. In 2006, the generation from wind was 922 GWh, an increase of 857 GWh since 1999.

There have been inquires from interested parties for 1,000-1,500 MW of additional capacity. There have been concerns for system reliability if the system is burdened with an excess of non-dispatchable generation. Facing substantial wind additions in the near term the Alberta Electric System Operator (AESO) established a temporary 900 MW threshold to ensure continued system reliability.

A number of recent studies sponsored by the AESO have attempted to better define the issues and to recommend solutions. As a result the AESO have recently removed the threshold restriction with the plans to undertake a series of mitigating measures for increasing wind penetration.

Existing measures:

- The Energy Market Merit Order (EMMO). EMMO currently balances supply and demand and is established at gate closing 2 hours before the delivery hour. EMMO in combination with regulating reserves can be dispatched as often as necessary to maintain supply demand balance.
- Regulating Reserves (capable of ramping in 10 minutes or less)
- Load / Supply Following Services – this would introduce a new level of regulating reserves, slightly less rapid in response and therefore able to be met by a wider range of generators, the cost of these additional reserves would be borne by load as at present;
- Improved wind speed forecasting costs to be borne by individual wind generators; and
- Wind Generation Power Management and Control (effectively curtailment used when wind generation is too high), the costs of lost revenue and additional required equipment would be borne by individual wind generators

They also stress that geographic diversity would provide a measure of firm capacity for the wind portfolio, however the system operator has no power to control this as the decision would be made by investors.

The AESO facilitates Alberta's wholesale electricity market, which has about 200 participants and about $5 billion in annual energy transactions, and is accountable for the administration and regulation of the load settlement function. The AESO provides fair and open access to the Alberta Interconnected Electric System (AIES) for generation and distribution companies and large industrial consumers of electricity, and contracts with transmission facility owners to acquire transmission services and provide customer access. The AESO is independent of any industry affiliations and owns no transmission assets. Consistent with its responsibility to ensure system reliability, the AESO procures ancillary service, including operating reserves, to address contingencies and moment-to-moment changes in load. The company manages the exchange of electric energy and system support services between Alberta and its neighbouring jurisdictions. To do all this the AESO:

- Determines the economic merit order for energy dispatch.
- Sets the schedule for dispatching generating units.
- Reports the pool price for each hour.
- Carries out financial settlement for the electric energy exchanged through the pool.

The AESO is an open-access market that accepts Bids and Offers on electricity, and trades electricity on the lowest price basis. The market is a spot market, which matches demand with the lowest cost generation to establish an hourly pool price. Access to the market pool is available on a non-discriminatory basis to all generators, distributors, importers, and exporters that meet the qualifications set by the regulators.

As an alternative to buying and selling electricity at the wholesale market prices, participants can participate in Net Settlement Instructions. These allow buyers and sellers of electricity to enter directly into contracts for a fixed amount of power at a fixed price over a specified time period in the future. These offer a stable pricing arrangement that customers and generators can use to hedge against volatile electricity prices.

Wind generation is a non-dispatchable market participant and thus a price taker ($0 offer) which can depress price returns, increase risk and in turn reduce potential for its development from an economic perspective. Wind generation in Alberta therefore relies on Net Settlement Instructions (NSI) with green power premiums to remain competitive in the Alberta market. All participants eligible to buy directly from the Pool are eligible to set up an NSI with any participant eligible to sell to the pool. The AESO manages the contract (without knowing the contract price) by managing the scheduling and dispatch of power. The buyer is guaranteed supply and price of power. The generator is only liable for difference if they fail to provide power as scheduled and the pool has to provide. At that point the generator is charged the spot market price. Both participants pay a settlement price to AESO for the management services.

The premiums in the form of Renewable Energy Certificates can be sold with the electricity or separately as a commodity. An example of such a transaction follows:

Commencing 1 September 2001, Calgary Transit (Calgary, Alberta) entered into a partnership with the local municipal LDC and a private Alberta wind developer to purchase the GHG credits from the wind system equivalent to the electricity demand from its transit system. Using wind-generated power currently reduces CO_2 emissions by 26,000 tonnes annually. The CTrain is now 100 percent emissions free. It is the first public light rail transit system in North America to power its train fleet with wind-generated electricity.

Typical for the majority of developers in Alberta, wind plants operate as merchant plants, meaning that generators are paid the hourly pool price for the electricity that is delivered to the grid. The generator will sell the environmental attributes separately to buyers in the form of a Renewable Energy Certificate.

- ***Support Mechanisms***

  Supports exist for wind generators from provincial government, federal government and regional utility agencies.

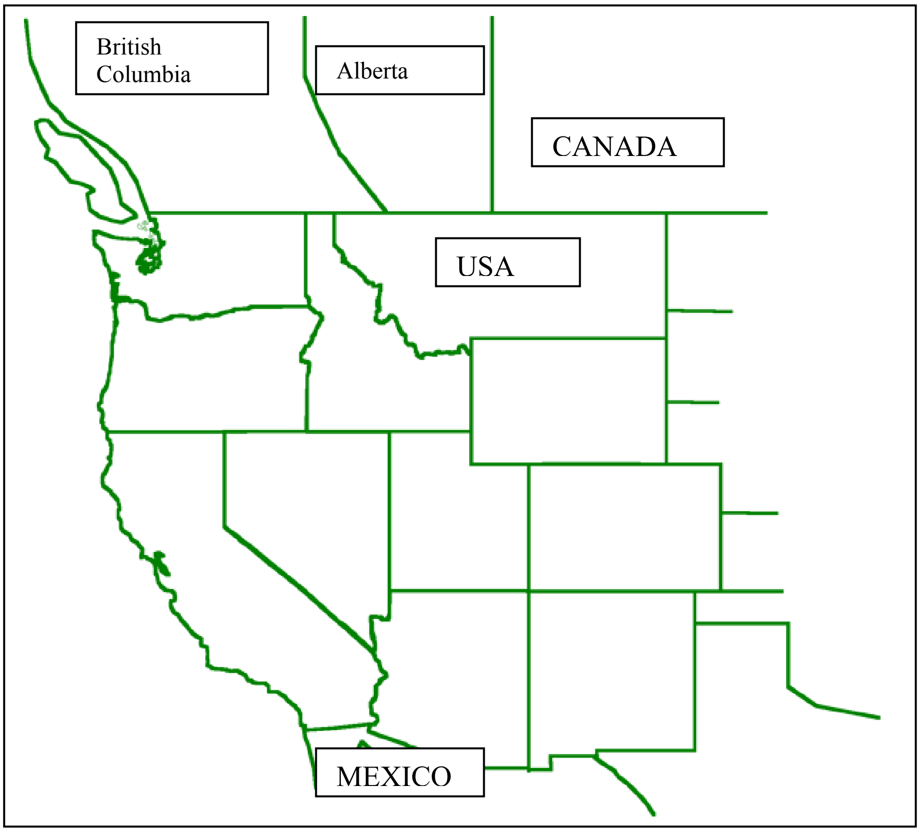
  There are currently no directly sponsored programs by the province for the support of wind or other variable generation technologies. On the other hand, ninety per cent of the electricity used in government facilities is procured from green power sources, such as a wind farm in Southern Alberta, through concessionary NSI. As well, Alberta is the first jurisdiction in North America to have regulations in place to reduce greenhouse gas emissions. Starting July 1, 2007 Alberta facilities that emit more than 100,000 tonnes of greenhouse gases a year are required to reduce their emissions intensity by 12 per cent under the *Climate Change and Emissions Management Act.* Targets have been shown to be a stimulus for investment in carbon offset projects which can result in long-term NSI contracts for wind farms.

  There is one federal program which is eligible within Alberta, the Canadian federal government ecoEnergy program. ecoENERGY for Renewable Power provides an incentive of $0.01 / kilowatt-hour for up to 10 years to eligible low-impact, renewable electricity projects (including wind) greater than 1 MW constructed over the next four years, April 1, 2007 to March 31, 2011.

  The Alberta System is also part of the Western Electricity Coordinating Council an affiliation of U.S. States and Canadian Provinces that are part of the Western transmission interconnect system. As of June 2007, this agency helped establish and now is home to the Western Renewable Energy Generation Information System or WREGIS, a renewable energy registry and tracking system for the Western Interconnection. The role of WREGIS is to develop and implement a system tracking renewable energy generation. This system will help ensure the credibility of the "green" value of renewable electricity and facilitate the growth of renewable energy throughout the Western U.S. and Canada.

  Participation in WREGIS is voluntary. Besides Alberta WREGIS will be available in the area covered by the Western Interconnection System, which covers 14 States, 2 Provinces and part of Baja California (Washington, Oregon, California, Nevada, Idaho, Utah, New Mexico, Arizona, Colorado, Wyoming, Montana, Texas, South Dakota, Nebraska, British Columbia, Alberta and the northern portion of Baja California, Mexico).

Annex 8, Figure 9: The WREGIS System Coverage



Electricity generated from renewable energy comprises two distinct tradable commodities – the underlying electricity and the associated "environmental" attributes. Renewable energy certificates (known as WREGIS certificates if issued by WREGIS) represent a contractual right to the environmental attributes. The WREGIS certificates have value to consumers and can be sold separately from the electricity.

Account Holders are expected to include load serving entities, balancing authorities, generators, marketers, regulators and others. WREGIS account holders will buy and sell their certificates on-line. Small distributed generators are allowed to participate.

There are expected to be multiple benefits of WREGIS which ultimately has the aim of expanding RE generation. These benefits include:

- Prevent double counting of green credits
- Verify quantity of RE generated in the Western Interconnection
- Issue and retire Renewable Energy Certificates (RECs) with unique serial numbers
- Track RE transactions at the wholesale level
- Enable verification of compliance with state/ provincial RE policies/programs
- Enable Verification of green power claims

- Facilitate commercial trading of RECs
- Create REC transaction reports for regulators
- Be compatible with other REC tracking systems to facilitate imports and exports of RECs

UK Government Energy policy

The following text is extracted from a UK Government summary of the White Paper "Our Energy Future – creating a low carbon economy."
"We will have four goals for our energy policy:

- to put ourselves on a path to cut the UK's CO2 emissions by some 60% by about 2050, with real progress by 2020;
- to maintain the reliability of energy supplies;
- to promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and improve our productivity; and
- to ensure that every home is adequately and affordably heated.

We believe these four goals can be achieved together. As far as possible we will ensure the market framework and policy instruments reinforce each other to achieve our goals. Energy efficiency is likely to be the cheapest, safest way of meeting all four objectives. Renewable energy will also play an important part in reducing carbon emissions, while strengthening energy security and improving our industrial competitiveness as we develop cleaner technologies, products and processes.

There will inevitably from time to time be tensions between different objectives. There is no simple mechanism for determining the relative 'weights' of differing objectives. But our approach is guided by the following considerations:

- significant damaging climate change is an environmental limit that should not be breached. We need to keep the UK on a path to 60% cuts in carbon dioxide emissions by 2050;
- reliable energy supplies are fundamental to the economy as a whole and to sustainable development. An adequate level of energy security must be satisfied at all times in both the short and longer-term;
- liberalised and competitive markets will continue to be a cornerstone of energy policy. Where the market alone cannot create the right signals we will take steps that encourage business to innovate and develop new opportunities to deliver the outcomes we are seeking; and
- our policies should take account of impacts on all sectors of society.

Specific measures will be needed for particular groups of people, for example to support those for whom energy bills form a disproportionate burden.

We do not propose to set targets for the share of total energy or electricity supply to be met from different fuels. We do not believe Government is equipped to decide the composition of the fuel mix. We prefer to create a market framework, reinforced by long-term policy measures, which will give investors, business and consumers the right incentives to find the balance that will most effectively meet our overall goals.

We recognise this approach is not enough on its own. In particular, specific measures are needed to stimulate the growth in renewable energy that will allow it to achieve the economies of scale and maturity that will significantly reduce its costs. In January 2000 we announced our aim for renewables to supply 10% of UK electricity in 2010, subject to the costs being acceptable to the consumer. We introduced in April 2000 the Renewables Obligation. We exempted renewables from the climate change levy. By 2010, these measures will provide support to the renewables industry of around £1 billion a year. This is designed to deliver the required expansion in renewables by then. We now set the ambition of doubling renewables' share of electricity generation in the decade after that.

In reducing carbon dioxide emissions, our priority is to strengthen the contribution of energy efficiency and renewables. They will have to achieve far more in the next 20 years than previously. We believe such ambitious progress is achievable, but uncertain.

Nuclear power is currently an important source of carbon-free electricity. However its current economics make it an unattractive option for new, carbon-free generating capacity. There are also important issues of nuclear waste to be resolved, including legacy waste and continued waste arising from other sources. We do not make specific proposals for building new nuclear power stations. However we do not rule out the possibility that at some point in the future new nuclear build might be necessary if we are to meet our carbon targets. Before any decision to proceed with new build there will need to be the fullest public consultation and the publication of a further white paper setting out our proposals.

Coal fired generation will also have an important part to play in widening energy diversity provided ways can be found materially to reduce its carbon emissions. We will continue to support relevant research projects to develop options for cleaner coal technologies and for carbon capture and storage. Domestic coal production is likely to continue to decline as existing pits reach the ends of their geological and economic lives. We will introduce an investment aid scheme to help existing pits develop new reserves, where they are economically viable and help safeguard jobs.

To achieve our goal of **reducing carbon emissions** we need to continue to decouple economic growth from energy use and pollution. Since 1970 overall energy consumption in the UK has increased by around 10%, while the size of the economy has doubled. We need to accelerate this trend.

Discussions to tackle climate change beyond 2008-12 will start soon. On the basis of existing policies we expect UK carbon dioxide emissions of some 135 million tonnes of carbon (MtC) in 2020. We expect to aim for cuts in carbon of 15-25 MtC below that by 2020. We believe it is possible to achieve this by reducing our energy consumption, together with a substantial increase in renewable energy. By making our intentions clear we aim to provide the signals needed for firms to invest - and help British manufacturers be ahead of the game in developing green technologies we expect to play a large part in the world's future prosperity.

Central to the future market and policy framework will be a carbon emissions trading scheme. We have already launched our own voluntary UK trading scheme. From 2005 electricity generators, oil refineries and other industry sectors are expected to be part of a much larger EU-wide scheme. By setting caps on emissions the scheme will provide clear incentives for investment in energy efficiency and cleaner technologies at the lowest cost. We will encourage expanded opportunities for trading at all levels. We will work with our EU partners to extend where appropriate the coverage of the EU scheme in due course. We will consider the issues involved in the linkages between tax and tradable permit schemes further as the EU scheme becomes clearer.

On its own emissions trading will not be enough to deliver our environmental goals. We will need additional measures, for example to stimulate further energy efficiency in business, the public sector and households. Policies to raise the energy efficiency of products and buildings will have an important role. We will develop the present energy efficiency commitment, which requires electricity and gas suppliers to encourage their domestic customers to invest in measures such as cavity wall insulation. We aim to bring forward to 2005 the next revision of the Building Regulations to raise standards for energy efficiency in new buildings and refurbishments. We will push in Europe for higher energy efficiency standards in tradable goods such as fridges and personal computers. We will encourage improvements in efficiency and lower carbon fuels in transport. We will provide further encouragement for renewable energy and infrastructure investment through measures such as capital grants and a more supportive approach to planning. We are increasing the funding for renewables capital grants by £60 million, additional to the £38 million of extra funding announced in the 2002 Spending Review. We will set an example throughout the public sector by improving energy efficiency in buildings and procurement.

Our second goal is to **maintain the reliability of Britain's energy supplies**. This requires action on many fronts. We need the right infrastructure and regulatory system at home and liberalised EU energy markets. We will pursue closer international relationships to promote regional stability and economic reform in key producing areas, mutual understanding of the functioning of markets, and conditions for foreign direct investment to facilitate further infrastructure investment in the world's diverse gas and oil regions.

In liberalised markets, forward prices will send signals about the need for future investment. Suppliers will act on these signals, and on their own assessments of risk and opportunity, to innovate and plan to meet those needs. In response to current market signals some companies already plan to increase gas imports through our pipeline to Belgium; others are exploring options for gas storage and new LNG importing facilities. These developments help provide reassurance that the market will invest in the capacity we need to provide reliable energy supplies.

Thirdly, we are determined to promote **competitive energy markets**, in the UK and beyond. This will help to raise sustainable rates of economic growth and support our competitiveness through reliable and affordable energy. A competitive energy sector is important to the whole economy's competitiveness and productivity. We need greater resource productivity in business so our firms use energy more efficiently, reduce carbon dioxide emissions and cut costs at the same time. To do that we will encourage firms to innovate and minimise costs and deliver better quality goods and services. We will continue our commitment to competitive energy markets and use market-based instruments to deliver our wider energy policy goals. We will work with business to help them prepare for the low carbon economy and seize the opportunities it provides. Through our new sector skills network we will work with the energy industry to develop the skills industry needs.

Our final goal is to **ensure that every home is adequately and affordably heated**. In 1996, 5½ million households needed to spend more than 10% of their income on heating their homes adequately. Already, falling prices and higher social security benefits have helped reduce this number to around 3 million.

Alongside our policies to cut poverty we need to tackle the problem of old, poorly insulated, draughty homes, where much spending on energy is wasted. In 2001 our fuel poverty strategy set out policies to end fuel poverty in vulnerable households in England by 2010. We further aim that as far as reasonably practical nobody in Britain should be living in fuel poverty by 2016-18. Grant schemes and the energy efficiency commitment are already improving homes through better insulation, more efficient heating systems and minimising draughts. Later this year we will review the results of these policies and decide what more needs to be done to achieve our fuel poverty objectives.

Technological innovation will have a key part to play in underpinning our goals and delivering a low carbon economy cost-effectively. We will support research, development and innovation to encourage the development of new, longer-term options such as the hydrogen economy, and where necessary to enable emerging technologies, such as renewables and new energy efficiency technologies. A new national energy research centre will be established by the Research Councils.

We will work through our national programmes, international collaborations and multilateral programmes to enable us to maximise return on our participation. We will work with our G8 and EU partners to develop climate change technologies to help us meet our carbon reduction ambitions and help others, especially the developing world, meet theirs.

We need to prepare for an energy system likely to be quite different from today. It will be for the market to develop and invest in this. But we need to set clear goals and a strategy within which the market has the confidence, ability and sense of long-term commitment to do so. Our approach is based on the following key principles:

- energy investments are generally long-term;
- the cheapest, cleanest and safest way of meeting all our goals is to use less energy. We must improve energy efficiency far more in the next 20 years than in the last 20;
- a well-designed, transparent and open energy market is the best way of achieving efficient outcomes. We will wherever possible use market instruments to achieve our goals. In particular, emissions trading will be at the centre of our energy markets from 2005 onwards;
- we will need to continue to use trading as well as other measures to reduce carbon, along with measures to drive up energy efficiency in homes, products and transport;
- the nationwide and local electricity grids, metering systems and regulatory arrangements that were created for a world of large-scale, centralised power stations will need restructuring over the next 20 years to support the emergence of far more renewables and small-scale, distributed electricity generation;
- the future energy system will require greater involvement from English regions and from local communities, complemented by a planning system that is more helpful to investment in infrastructure and new electricity generation, particularly renewables.

Strong links with the Devolved Administrations, who are already fully engaged on a wide range of energy issues, will continue to be essential;

- diversity is the best way of protecting ourselves against interruptions of supply, sudden price rises, terrorism or other threats to security of supply. As we become a net energy importer we will need many sources, suppliers and routes. International relations in Europe and worldwide will be increasingly important to achieving our overall energy aims;

- we will seek out the best ways to influence outcomes in line with the principles of better regulation, maximising use of market-based and/or voluntary mechanisms, promoting regulations only where they are clearly necessary and well designed.

Where regulation is required we will work to make sure it takes account of the impact on key stakeholders to minimize the burdens particularly on smaller and medium sized enterprises; and when designing new energy policies, we will consider their impact on all of our energy policy objectives, in line with our overall approach to sustainable development.

We have set out a long-term framework to deliver our environmental, security of supply, competitiveness and social goals. Because energy requires very long-term investment we have looked ahead to 2050 to set the overall context. We have reviewed what we will need to have achieved by 2020 if we are to be confident we are moving in the right direction, fast enough, to deliver our aims for 2050. We have sought to define a longterm strategic vision for energy policy. We have set out long-term strategies and, against that background, shorter-term policies to set us on the path we need to be on. We have not sought to define every detail of the policies we need to pursue over the next 20 years and beyond. That would not be realistic. We need to be prepared, within a firm and clear strategic context, to review the impact of policy changes and to update and amend our detailed policy measures in the light of experience.

We believe, for example, that technological innovation will have an important contribution to make in helping to deliver our long-term vision. This will bring new opportunities and possibly new challenges that we cannot imagine now. We have to be prepared to adapt and evolve our policies in the light of those opportunities and wider changes in society.

We will strengthen our energy policy capabilities, including annual public reports on progress towards our aims and the steps we are taking to ensure we remain on track.

This will not be the last major strategic statement on energy policy. But it sets a new direction, and a new determination, to deliver very significant changes in both the short and longer terms. It is a massive challenge. But it is one that has to be met. And one we believe we can meet.

ANNEX 9 - REFERENCES

List of people met

CEA

- Shri R. Dhiya, Member (Technical)
- Shri Suresh Chander, CE (Thermal Engg. & Technology)
- Shri A.K. Gupta, CE (TRM)

CERC

- Bhanu Bushan, Member
- R.Krishnamoorthy, Member
- K. Biswal Chief (Finance)
- Sushanta K. Chatterjee, Deputy Chief (Regulatory Affairs)

Damodar Valley Corporation

- Mr T K Gupta – (Director of Accounts)

DERC

- Mr. Berjindra Singh, Chairman
- Mr. K. Venugopal (Member)
- Mr. Bijoy Kumar Sahoo, Director (Engg.)

Mahagenco

- Mr G J Girase (Director of Finance)
- Mr J Srinivasan (Chief General Manager, Finance and Accounts)
- Mr R D Adhyaru (Chief General Manager, Project Monitoring)

MERC

- Dr Pramod Deo (Chairman)

NTPC

- Mr. R.S. Sharama (Director-Commercial)
- Mr. I.J. Kapoor (ED-Commercial)
- C.K. Mondal DGM
- Mr. Atish Basu Roy DGM
- Mr. B.I. Goel, STA

Steag - Encotec

- Mr B Anto (General Manager – Engineering: O&M)
- Mr S K Sinha (General Manager – Electrical)

WBPDCL

- Mr. M. Roychowdhury, ED (Finance)
- Mr. P.K. Chakrabarty Executive Director (Corporate)
- Mr. Amit Bhattacharyya, Company Secretary
- Mr. D. Mukherjee, GM (Operations)
- WBERC
- Mr. S.N. Gosh
- Mr. C.R. Bhaumik

Input from attendees at Workshop

Comments were received from attendees at the workshop entitled "Regulatory incentives for investing in renovation & modernization of coal-fired generating plants focusing on energy efficiency" held on Friday 2nd May 2008 at The Claridges Hotel, New Delhi. Senior officials of the following organizations were represented at the workshop:

- Central Electricity Authority
- Central Electricity Regulatory Commission
- CESC Limited
- Delhi Electricity Regulatory Commission
- Evonik
- GSECL
- Haryana Power Generation Corporation Limited
- Haryana Electricity Regulatory Commission
- HESCOM
- Hubli Electric Supply Company Ltd
- Karnataka Electricity Regulatory Commission
- KFW
- Madhya Pradesh Electricity Regulatory Commission
- Maharashtra Electricity Regulatory Commission
- Mahagenco
- Ministry of Power
- North Delhi Power Ltd
- NTPC
- Rajasthan Electricity Regulatory Commission
- Steag
- TNEB
- Uttar Pradesh Electricity Regulatory Commission

List of documents reviewed

a. Electricity Act, 2003
b. Electricity Conservation Act, 2001
c. Electricity National Policy
d. National Tariff Policy
e. National Electricity Plan
f. Policy for Private Sector Participation in R&M dated 28th October 1995
g. MoP guidelines for R&M dated 3rd Feb, 2004
h. Expert Committee on Integrated Energy Policy
i. CERC- Terms and Conditions of Tariff along with all its amendments
j. UPERC-Terms and Conditions of Generation Tariff along with its proposed amendments
k. UPERC-Terms and Conditions of Distribution Tariff
l. UPERC-Guidelines for load forecast, Resource plans and Power Procurement plans
m. UPERC Order dated 7th November 2006 regarding refurbishment of 5*200 MW units at Obra B TPS
n. UP Rajaya Vidyut Utpadan Nigam Ltd. Tariff Order dated 26th March 2007 for the Multi Year Period 2005-06 to 2007-08
o. UPERC Review Order of Multi Year Tariff Order for the period 2005 to 2007 for UP Rajaya Vidyut Utpadan Nigam Ltd. dated 10th October 2007
p. West Bengal Terms and Conditions of Tariff Regulation 2007 dated 9th February 2007 along with the proposed amendments
q. MERC Terms and Conditions of Generation Tariff
r. MERC MYT Order for TPC-G for FY 2007-08 to FY 2009-10 dated 2nd April 2007
s. MERC MYT Order of REL (G) for FY 2007-08 to FY 2009-10 dated 18th April 2007
t. CEA performance review of thermal power stations 2006-7