Chapter 7

Policy Regimes and Sensitivities

Introduction

In the traditional approach to power sector planning investment decisions were made independent of the environmental considerations, which were essentially deferred to the siting stage of the individual projects. Although great strides have been made in project level EIAs and have succeeded in forcing project developers to become more sensitive to environmental issues, they fail to address environmental issues at the planning or the decision making process. Thus, in view of the formidable environmental fallout of power sector development and the sustainability of a development process, the primary objective should be to incorporate environmental considerations at the decision making stage. Appropriately chosen development strategies, by influencing the choice of technology basket, long term energy policies, costs and tariff policies, would guide the system along a more desirable development trajectory. The fundamental question, thus, is not just whether individual projects are environmentally agreeable but what the relative environmental impacts are of alternative development strategies. This diagnostic study is an attempt to enrich the vista of the decision-maker by identifying and assessing environmental and economic consequences of power sector development under alternative policy regimes. The study is only meant to be indicative and does not attempt to identify and propose, per se, a single optimal policy regime. The expansion plan model, developed in chapter-3, is used to simulate power system development in Andhra Pradesh. Experiments with the model, intended to be illustrative of the uses of the model as a policy analytical tool to assist decision makers, include simulation of different strategy oriented scenarios for Andhra Pradesh power sector.

Mitigation options are technical choices available to the operating entities, which once selected completely specify the technology and use. Pollution being a negative externality if left to the market has little inducement to be reduced through the adoption of appropriate mitigation options. For mitigation options to be translated into various activities, appropriate policies need to be formulated within a legal framework to support their implementation. Policies are instruments or combination of instruments stipulated by the Governments, and adopted by production-consumption entities and the implementing agencies, having considerable bearing on the choice of technical options and their operating practices. Usually studies capture policies
through the construction of appropriate scenarios. Development strategies, which are central to this study, may be defined as mitigation options supported by rational and effective policies. Although the distinction between the strategies and scenarios is not just a semantic artifice, the demarcation line between them is not at all intrinsically clear. Thus, to avoid confusion this exercise chooses to refer to strategies or policy regimes as Policy Driven Scenarios, and their variations as Sensitivities. These policy-driven scenarios may be broadly classified under the following:

A. Economic and Financial Cost Regimes;
B. Market Based Instruments/Incentives;
C. Promotion of Technology Options;
D. Command-and-Control Policies;
E. Combined Policy Packages.

The alternative development strategies under these broad classes, considered for this study, with an eye on environmental impact reduction, are listed below along with the analytical summary of simulation results. It may be mentioned here that the Business-as-Usual Scenario (Economic Costs) is treated as the reference scenario against which all the other policy driven scenarios are discussed.

Policy Driven Scenarios

A. Economic and Financial Cost Regimes

1. Business-as-Usual with Economic Costs (BAU)

As already mentioned in chapter-6, Business-as-Usual Scenario depicts a regime where the existing situation and trend is presumed to prevail over the planning horizon along with the ongoing minimal reform process. This scenario is evaluated at economic costs and a discount rate of 12% is used for discounting costs to the base year 1996. No real escalations on fuel prices are considered. Environmental costs included are only control costs incurred on the mitigation instruments, as well as those expenses necessary to obtain environmental clearances for the projects. Infrastructural, institutional, economic, and financial bottlenecks are incorporated through the annual and overall build limits for each of the supply options. It is assumed that a maximum of four plants can be built each year for all coal and hydrocarbon based plants. Limits on the capability of harnessing renewable options are assumed on the basis of technology penetration data for the past couple of years. Thus, for renewable options it is

196 Although very detailed plant-wise output was generated, only aggregate information is tabulated and presented in the Appendices to keep the size of the thesis within manageable limits. Overall view of the results are discussed in this chapter with reference to the information generated.
assumed that approximately 3MWs of new small hydro projects can be put to operation per annum, and as for wind farm options 2MWs of capacity can be added per annum till 2006 and thereafter from the 11th plan 4MWs of capacity can be added. Further, it is assumed that a total of 15 plants of each plant type (not including the renewable options) may be added over the entire planning horizon, net of replacements. As it is assumed that no generic option can come up before 1999, the demand-supply balance requirements and minimum guarantee condition of the model is relaxed for the first two years of the planning period. Thus, for the first two years of the planning period provision is made for unserved energy in the model. A penalty of approximately Rs. \text{7/KWh} is charged for unserved energy along with an escalation rate of 10\% to account for the growing feeling of deprivation of the consumers over time. All assumptions and techno-economic norms along with the supply options pertaining to this scenario are discussed in chapter-6.

The demand for energy and power to be satisfied is prognosticated with the assumption that the monthly trends in unrestricted power demand would continue, along with explicit assumptions on the changing ratios of non-utility to utility. Price elasticities and moderate upward revisions in tariffs are assumed and accounted for in demand forecasting. Modest improvements in T&D losses are also considered to account for the expenses already incurred and/or committed by the Board on T&D improvements. From the energy and peak demand forecasts as discussed in chapter-5 and using the LDC parameters derived in chapter-6, the three load levels of the LDCs, for each year of the planning horizon, are obtained. These load levels along with the annual energy forecasts for BAU are tabulated in Appendix-1 (Table-A1.1). From these forecasts it is observed that the energy demand would grow at the rate of 5.3\% during the 9th plan and rise during the 10th and 11th plans growing at the rate of 7.8\% and 8.4\% respectively. The initial modest growth rate is primarily due to the implicit assumption of instantaneous adjustments to tariff increases. Thus, energy demand would register approximately 2.8 times increase from 37599GWh in 1996 to 106436.3GWh in 2011. As the table shows, peak demand grows 3.2 times from 5640MWs in 1996 to 18134.7MWs in 2011. The peak demand growth rates are 6\%, 9\% and 9.1\% for the 9th, 10th, and 11th plan periods respectively. The base and intermediate load levels for the entire planning horizon are also tabulated along with the energy and peak demand levels.
Results

Simulation results for this policy driven scenario are tabulated (Table-A1.2 to Table-A1.21) in Appendix-1.

The optimal development trajectory indicates that in order to meet the load level and energy requirements at the pre-specified level of reliability 11901MWs of fresh capacity have to be added to the system over the three plan periods, besides the 5166MWs of committed capacity. Thus, as evident from Table-A1.5, total installed capacity is observed to increase 3.4 times from 6735MWs in 1997 to 23105MWs in 2011. Baseline existing (excluding committed capacity) installed capacity includes 3432MWs of thermal capacity (with 99MWs of Gas thermal), 2650MWs of existing hydro projects, 44MWs of wind capacity and 11MWs of mini-hydel projects. Bulk of the committed capacity is coal thermal at 2810MWs, followed by 920MWs of naphtha based plants, 900MW pumped storage hydro project at Srisailam, and 536MWs of Gas based generation capacity. The baseline information indicates that substantial committed capacity would be commissioned towards the end of the 9th plan (around 2000/01). Thus, even though from 1999 fresh capacity additions were permitted, it is observed that, notwithstanding existing capacity shortage, only 623MWs of future capacity are added over the 9th plan period. However, as the load and energy requirement shoots up during the 10th and 11th plan periods, substantial capacity additions are envisaged from the middle of 10th plan period through the terminal year of the 11th plan. Capacity additions envisaged over the 10th and 11th plans are 3141MWs and 8137MWs respectively. Thus, over the planning horizon 7420MWs of coal thermal (including 420MWs of imported coal based plant), 716MWs of domestic gas thermal, 3590MWs of LNG based, 110MWs major hydro project, and 65MWs of renewable capacity additions are envisaged.

The optimal patterns, i.e. type, size and timing, of future capacity additions are tabulated in Tables A1.2-A1.5. The pattern of future capacity addition display clearly preferred sequence of fuel types. With substantial peaking capacity shortage in the system, the future hydro project at Jurala is inducted into the system along with the maximum probable mini-hydel and wind capacity additions. Primarily driven by relative advantage of lower fuel cost, pithead coal thermal plants at Talcher emerges as the first preference along with these non-fossil fuel options, notwithstanding the higher capital costs arising from the inclusion of transmission costs for evacuation of power. Constrained by the physical availability of resources from Talcher, as evident from Tables-A1.12 and A1.13, pithead plant at Singareni is the next choice in the optimal capacity addition schedule. However, rapid production build-up and availability of coal from Singareni too are precluded by several factors as discussed in chapter-6. Consequently, combined cycle gas thermal plants get inducted but to a limited extent.
as availability of gas to the southern region is quite small compared to other regions (discussed in chapter-6). Thus, being constrained by the limited availability of domestic resources and with indigenous gas supply reaching a plateau, along with the associated uncertainties, LNG based combined cycle plants at regassification points or the coastal region emerges as the optimal choice along the development path. Since, LNG projects are still largely at a nascent stage; plenty of unresolved issues are yet to be ironed out, including firm and specific demand-supply-price agreements between buyers and sellers. With the objective of incorporating the imponderables and uncertainties associated with LNG based power plants, maximum annual build limits are imposed. The optimal capacity addition schedule indicates that as LNG based combined cycle plant additions reaches annual build limits, load centre plant using imported coal emerges as the feasible economic choice. Mini-hydel and wind projects are regularly inducted into the system to the maximum probable extent, primarily for peaking purposes, with a clear edge of mini-hydel projects over the wind projects. Thus, maximum permissible penetration of mini-hydel technology is envisaged over the planning horizon, along with substantial addition of wind technologies. Further, during the 11th plan period when peak demand is quite high, additional gas and LNG based peaking-plants (open cycle plants) are picked up. *Load centre plants using domestic coal, naphtha based plants, and plants using washed coal are not preferred.* The pattern of capacity additions over the plan periods and timing of capacity additions are illustrated in charts-1.6 and 1.7.

Share of fuel types in total installed capacity, as depicted in Chart-1.1 and tabulated in Table-A1.5, indicates the predominance of domestic coal based plants. However, this share fluctuates with a steady decline over the 11th plan period. With only a single hydro project expected, the share of hydro in total installed capacity rapidly declines over the plan years. Regarding naphtha based plants, since apart from the committed plants (which is steadily added over the 9th plan) no fresh capacity addition takes place, its share too gradually declines in total installed capacity from the 10th plan onwards. It is only the share of LNG based plants in total installed capacity that registers a clearly discernable upward trend, specifically during the 11th plan period.

The levels of output produced by different plants at different demand levels and assurance of reliability level have important bearing on the type, size and timing of capacity additions. The economic utilization or dispatch of the various fuel-types along the load duration curves for each year of the planning horizon are tabulated, in Tables-A1.6 to A1.8, as shares in total load generation in each mode of operation. The shares indicate that plants using domestic coal are predominantly responsible for meeting the base load of the system. Share of domestic coal in base load generation goes up steadily over the 9th and 10th plans from 64.4% in 1997 to
83.2% in 2007. However, thereafter this share declines although still remaining the major contributor to the base load of the system. Hydro options, although contribute significantly to the base load, complementing coal based plants, registers a steady decline in the base mode over the plan years. Over the 9th plan, with many naphtha based committed plants becoming online, the share of this fuel type in meeting the base load would increase steadily, but, thereafter, with no more fresh capacity additions, this share is observed to decline. Domestic gas towards the initial years of the planning period and to some extent during the 10th plan is observed to make some contribution towards meeting the base load. However, both naphtha and domestic gas makes small contributions to the base mode compared to domestic coal and hydro based plants. The most significant observation is that over the 11th plan share of LNG in meeting the base load goes up considerably displacing domestic coal based generation from the base mode. Imported coal option also contributes towards meeting the base load of the system from the terminal years of the 11th plan. These are clearly brought out in the Chart-1.3. As chart-1.4 shows, hydro projects primarily cater to the intermediate load, though towards the later years of the planning horizon their share declines, being supplemented by domestic coal thermal generation. Both wind and gas options indicate a small contribution over the 10th and 11th plan periods. As indicated in Chart-1.5, for the first two years of the planning horizon when there is substantial peaking capacity shortage and with no new plants getting introduced into the system (by assumption) it is only wind option that would operate as peaking plants. During these initial years other supply options, including hydro projects, would be concerned with meeting the base and intermediate load, achieving only partial success in meeting the intermediate load. However, a clearly discernable changing pattern of plant loading for meeting the peak load requirements per annum emerges along the optimal development trajectory. Hydro options, including mini hydel projects, are the prime contributors towards meeting the peak load. However, the share of major hydro projects in meeting the peak demand declines over the plan years as the share of coal thermal generation increases from the 10th plan onwards, being displaced by LNG plants from the base and intermediate modes. Although, the share of naphtha in meeting the peak demand declines over the 11th plan, it continues to contribute more in the peak than base mode. Share of LNG marks a steady increase over the 11th plan period. Imported coal based plants, starting out as peaking plant, matures to be a base load option towards the terminal years of the planning horizon. A pumped storage hydro plant, since it is brought online, contributes only to the peak mode. Mini-hydel and wind projects although have limited potential mainly contribute to the peak mode, with mini-hydel projects also making small contribution to the base mode and wind to the intermediate mode.
Total generation, as tabulated in Table-A1.9, goes up 3.04 times from 37421.59GWh in 1997 to 113918.3GWh in 2011. Energy generation at busbar goes up from 35128.48GWh in 1997 to 106995.2GWh in 2011. It is observed that although initially auxiliary consumption goes up, because of more and more coal thermal plants getting introduced into the system; auxiliary consumption declines as more efficient hydrocarbon based plants get commissioned.

An interesting observation, revealed in this table, is that in 2001 new capacity is generating only 7% of the total generation at busbar, which goes up to 33% in 2006 and further to 64% in 2011. It is, thus, clearly evident that the newer and more efficient plants would eventually emerge as the prime contributor to the total energy generation at busbar, displacing the relatively inefficient and operationally expensive existing plants from the base mode. It is further observed that towards the initial years with inadequate capacity in the system, to meet the intermediate and peak loads, all existing thermal and hydel plants were concerned with meeting the base demand, with hydro plants mostly catering to the intermediate load. However, as more and more efficient thermal plants get introduced into the system, the hydro plants are assigned towards meeting the peak and intermediate loads. With further capacity additions the new plants replace the existing coal thermal plants (excepting for a few efficient plants) as base load plants. The existing coal plants are gradually pushed up to meet the intermediate load and subsequently peak load. A careful study of the plant-wise output reveals that it is in fact optimal to operate some of the existing inefficient coal plants only at their minimum level of operation. Thus, if the PPPs are entrusted with future capacity additions then, it may be more economical for the utility to back down some of its inefficient existing plants and buy power at higher PLF from the PPPs. Shares of fuel types in total energy generation, as tabulated in Table-A1.10 and depicted in Chart-1.2, indicate that share of domestic coal in total generation increases through the 9th and 10th plans, a consequence of substantial capacity additions and committed plants, but, being replaced by LNG, declines over the 11th plan. Share of naphtha in total generation follows a similar trend as that of coal thermal over the planning horizon. The share of hydro in total generation also declines over the planning horizon. Fluctuations in the shares of domestic gas indicate considerable switching between base mode and peak mode generation, but essentially meeting peak load over the 11th plan. The predominance of coal in total generation and the changing fuel mix in total energy generation has important environmental implications. The PLFs for each fuel types are tabulated in Table-A1.11 and illustrated in Chart-1.8. The declining overall PLF from 63.4% in 1997 to 56.3% in 2011 is due to the influence of a declining SLF over the plan years. However, a declining PLF implies that increasing portions of the productive capacity of the system would remain underutilized, thereby, adding to the system costs.
Chart-1.9 illustrating share of each fossil fuel in total fuel requirements shows domestic coal to be the mainstay, but fast getting replaced by LNG from the 11th plan period. However, even when LNG has substantially displaced domestic coal in generation and total fuel requirement, domestic coal continues to account for 72.6% of the total fuel requirement against 18.6% for LNG. Inclusive of imported coal, the share of coal amounts to more than 75% in the total fuel requirement.

Table-A1.15 presents the attributes satisfying reliability criteria, i.e. the reserve capacities and maximum unmet energy. There is unmet energy only for the first two years when there is not enough capacity in the system and it is assumed that no new plants would come up. Notwithstanding an excess of installed capacity over peak demand by 13.27% in 1997, utilizable capacity falls short of peak load by about 4%. However, from 1999 as new capacity is added, along with the commissioning of committed plants, guaranteed power and energy is ensured. An interesting observation is that between 1999 and 2003 there is a sudden jump in reserve capacity, hitting maximum during 2000 and 2001. The total installed capacity exceeded peak load by about 57% in 2001, but stabilizes around 27-28% beyond 2003. This phenomenon is explained by the sudden upsurge in the commissioning of committed plants between 1999 and 2001. It is further observed from Chart-1.14 that reserve capacity in ‘cold condition’ declines from 2001 and stabilizes beyond 2004. However, reserve capacity in ‘hot condition’, i.e. plant spinning reserve, marks a steady increase over the planning horizon. This, supports the thesis that as the system grows requirement of standby capacity in ‘cold’ condition declines, since reserve capacity in ‘hot condition’ balances the overall reserve requirement.

The pattern of development under Business-as-Usual scenario as discussed above has several cost and environmental implications. Failure to meet the targets for capacity additions over the 8th and the earlier plans, apart from high future demand, is also responsible for higher capacity additions over the next three plan periods. The massive capacity additions required over the planning horizon, assuming that the committed plants would actually be commissioned on schedule with no time and cost overruns, require mobilization of enormous amount of capital resources, besides that required on a regular basis as operating capital requirements, depreciation, debt servicing, etc. The present value economic cost (cost as defined by the objective function) obtained for this development scenario is Rs.396.9 billion (includes present value cost of unmet energy at Rs.51.52 billion) and a levelised average cost (sent-out) of 1.06 Rs/KWh. Levelised average cost of sent-out including annuitized capital costs of existing and committed plants amounts to 1.74 Rs/KWh. Levelised average cost for future plant is obtained as 1.25 Rs/KWh; which is higher than the overall levelised average cost, since it includes capital cost of future plants net of salvage value. It may be noted here that this
exercise is worked out for the utility and with the assumption that utility will be responsible for future capacity additions. However, with private producers entrusted with the responsibility of future capacity additions, in the face of acute financial distress of the SEBs, this levelised average cost of future plants would be higher. This is because most of the new PPPs being foreign collaborators implies that the foreign exchange components in the project costs would be higher. Besides, *inter alia*, finances raised in foreign capital markets require full risk guarantee. These would raise capital costs of projects considerably (by about 20-30%). Further, there are severe cost implications and risks associated with imported fuels, on which this development trajectory is so acutely dependent.

The pattern of the development path obtained for this scenario has quite pressing environmental implications. Notwithstanding the end-of-the-pipe control measures which are already included, excessive dependence on coal would render the development trajectory environmentally onerous. Tables-AI.16 to AI.19 shows the shares of each fuel class in annual emissions of TSP, SO\textsubscript{x}, NO\textsubscript{x}, and CO\textsubscript{2}. For TSP emissions domestic coal based generation may be held solely responsible, with very little, but gradually growing, contribution from imported coal around the terminal years of the 11\textsuperscript{th} plan. In case of SO\textsubscript{x} domestic coal accounts for most of the emission, with naphtha contributing only about 0.2%. However, it may be noted that contribution of domestic coal to SO\textsubscript{x} emission declines from 99.8% in 1997 to about 95.9% in 2011 being supplemented by contributions from imported coal. This indicates that as the dependence on relatively high sulfur imported coal increases from the 11\textsuperscript{th} plan onwards, with the domestic fuel availability hitting the plateau, SO\textsubscript{x} emissions may in fact emerge as a major threat requiring mitigation actions through installations of FGDs. Thus, as already mentioned in chapter-6, although at present SO\textsubscript{x} emission does not pose to be a threat and is taken care of through the construction of stacks with appropriate height, from the long-term perspective more direct mitigation measures may have to be adopted. The government already has made it mandatory for plants of 500MWs and above to have space for FGDs. Nevertheless, tall stacks would continue to be constructed as a safeguard against removal process breakdowns and adverse meteorological conditions. However, inclusion of FGDs would considerably raise the cost of electricity generation. Further, coal beneficiation may become mandatory once explicit emission standards for SO\textsubscript{x} are enacted and enforced. As in the case of the previous pollutants domestic coal emerges as the main emitter of NO\textsubscript{x}, supplemented by gas and naphtha in small doses. NO\textsubscript{x} emission from domestic coal combustion fluctuates between 99.2% and 97.2% till LNG plants are inducted into the system. With the induction of LNG generation in the system, share of domestic coal in NO\textsubscript{x} emission declines and that from LNG and imported coal goes up. This, as in the context of SO\textsubscript{x} emissions, has serious implications for the future evolution of the
power sector and the associated environmental impacts. As the development pattern indicates, beyond 11th plan, with the proliferation of imported fuel based generation and clustering of hydrocarbon based plants in and around the coastal regions of Andhra Pradesh, NOx emission may emerge as a major pollution hazard demanding explicit control measures. Over the 9th and 10th plan periods share of domestic coal in total CO2 emission is around 95% with naphtha and gas contributing the rest almost in equal proportions. However, from the 11th plan share of domestic coal in total CO2 emission declines to 82.3% by 2011, and the shares of LNG and imported coal goes up.

Although the shares of imported fuels in total emission of pollutants increase over the 11th plan, the fact that LNG has been predominantly replacing domestic coal, along with imported coal with a higher calorific value than domestic coal, the rate of increase of emission slows down considerably. This is clearly illustrated in charts-1.11 to 1.13. The most notable effect is observed on TSP and ash generated, and the least impact is observed on CO2 emission. Regarding SOx and NOx, it is observed that although there is an initial slow down in the 11th plan years, but there is a slight up turn from 2010 onwards. This should be taken as a warning bell for the future evolution of the power sector. Table-A1.21 shows that TSP emission increases 2.764 times from 65.31KiloTons in 1997 to 180.53Kilo Tons in 2011, SOx rises 2.854 times from 194.42KiloTons in 1997 to 554.86KiloTons in 2011, NOx emission triples from 175.8KiloTons in 1997 to 528.06KiloTons in 2011, and CO2 goes up 3.16 times from 28.48MillTons in 1997 to 89.93MillTons in 2011. However, it may be noted that there is an element of downward bias in TSP emission since it is assumed that 99% of the TSP emissions are trapped by ESP. Unfortunately, as already mentioned in chapter-4, the ESPs fail to mitigate to the full extent because of several factors. Thus, actual emissions of TSP would be much higher than what is obtained here. Possibly the most serious concern arises from the colossal quantum of ash discharged from the power plants. Ash discharged increases 2.76 times from 8.10MillTons in 1997 to 22.39MillTons in 2011. Besides causing widespread air pollution, this would adversely affect ambience and the ecosystem. Land required for the disposal of such enormous amount of ash increases from 0.065KiloHectares in 1997 to 0.179KiloHectares in 2011. Given that the present practice of ash disposal and ash pond management is far from adequate, revelations of such enormous discharge is daunting and crying for immediate measures to be adopted. The question that obviously arises is that were would the land required for ash disposal come from, without eating into productive agricultural land. Besides, the difficulty of getting land for ash storage and disposal is exacerbated by the fact that land utilized for ash disposal loses its original use and value, and is quite expensive to reclaim its productivity and use. However, as the share of hydrocarbon based generation increases over the
11th plan, it is observed that ash discharge almost stabilizes over this period. The cumulative emissions for this planning horizon are 1882.3 KiloTons of TSP, 5631.6 KiloTons of SO$_x$, 5148.8 KiloTons of NO$_x$, 845.8 MillTons of CO$_2$, and 233.4 MillTons of Ash. Chart-2.10 illustrates the shares of fuel types in cumulative emission of pollutants.

The enormous emission implications of this scenario arises from the predominance of coal based generation. The associated adverse environmental effects of coal mining would exacerbate the situation further. Moreover, with enormous capacity additions envisaged over the planning horizon the environmental sustainability can never be firmly established in the absence of ambient air quality assessment of the development path. Similar problems, which might question the feasibility of the optimal development trajectory, arise from the clustering of hydrocarbon based plants along the coastal region and the associated implications for ambient air quality. Thus, the actual environmental implications may be even more severe than what is envisaged here.

Sensitivity to this scenario is constructed to account for the real cost to the economy of depleting domestic resources. It is sometimes advocated that including scarcity rent of resources in the planning exercise may yield a development trajectory which is environmentally less hazardous.

Sensitivity to BAU Scenario

1(a). BAU with fuel cost escalations (BAU1)

As fuel resources are used there is a gradual depletion of finite domestic resources over time, and eventually move towards higher priced substitute fuels in the future. Rationally, if the fuel prices do not include this scarcity or users rent, for a given reserve the depletion rate would be greater and, hence, the time of depletion shorter. The users cost reflects the foregone surplus benefits of future consumption. To account for these scarcity rents escalation rates are used on fuel costs and are kept fixed in real terms. Thus, in this sensitivity analysis real escalation rates are charged on the fuel costs for each of the domestic fuels. The assumptions on the escalation rates made are: 2.5% per annum for Singareni coal, 2% per annum for Talcher coal, 3% per annum for indigenous gas, and 2% per annum for naphtha.

Sensitivity Results

The results of this sensitivity analysis are presented as comparative Tables-S1.1 to S1.14 in Appendix-1 (Continued). The optimal development path obtained indicates worsening of environmental situation as compared to the situation when scarcity rents were not included. The capacity addition schedule indicates that both the optimal technology mix and timing of
fresh capacity additions are different. Although domestic coal based capacity additions over the three plans are same, their timings are different. Thus, in this case domestic coal based capacity additions are brought forward during the early years of the 10th plan, thereby replacing gas and wind based supply options. Moreover, compared to the BAU scenario, in this scenario more of LNG and imported coal based options are added primarily replacing gas-based options. The optimal development path for this scenario then projects more LNG and imported coal plants and less of domestic gas as well as renewable options, as compared to the BAU scenario. The generation pattern obtained for this scenario indicates that during the early years of the planning horizon coal plants are essentially used to meet the base load, and less of gas and hydro options cater to base load as compared to BAU scenario. During this period hydro and gas are responsible for meeting the intermediate and peak loads respectively, excepting for the first two years when there is not enough capacity in the system. From the 10th plan onwards coal practically replaces domestic gas in all the modes of operation. During the 11th plan LNG and imported coal replaces domestic coal in base mode, which is then pushed up the LDC to contribute towards meeting the intermediate and peak loads. Although generation by LNG based options is higher as compared to BAU scenario, it is the higher contribution of domestic coal during 9th and 10th plan periods, greater contributions by imported coal options during the 11th plan period, which makes this development pattern dirtier than BAU. Further, contributions by environmentally clean wind and hydro option, and also relatively benign gas options, are lower as compared to the BAU scenario. Thus, higher share of domestic coal along with lower shares of gas, hydro and wind in total generation during the first two plans and lower shares of renewable options along with higher shares of imported fuels during the 11th plan is responsible for the worsening of environmental situation. Consequently, annual emissions of all the pollutants are higher in this case as against BAU scenario. Cumulative emission indicate that TSP, Ash and SOx emissions increases over BAU scenario are slightly more than NOx and CO2 emissions increases. Finally, since the present value cost, levelised average cost of sent-out, levelised average cost for future plants are all higher for this case, this situation of including scarcity rents is a clear lose-lose situation. The only economic advantage of this scenario, although of little consolation, is the requirement of lower installed capacity and consequential lower reserve capacity to guarantee reliability of supply till the terminal year of the 11th plan. Thus, under the present set of assumptions and norms for Andhra Pradesh power sector, inclusion of scarcity rents on domestic fuels would worsen the situation on environmental and financial considerations, unless efforts are made to overcome the existing hindrances and increase penetration of major hydro projects and renewable technologies.
CHARTS for Business-as-Usual Scenario (Economic Costs)

Chart-1.1
Share of Fuel Types in Total Installed Capacity

Chart-1.2
Share of Each Fuel Type in Total Energy Generation
CHARTS for Business-as-Usual Scenario (Economic Costs)

Chart-1.3
Share of Fuel Type in Base Mode Generation

Chart-1.4
Share of Each fuel Types in Intermediate Mode Generation
Chart-1.5
Share of Each Fuel Types in Peak Mode Generation

Chart-1.6
Capacity Additions over the Plan Periods (MWs)
CHARTS for Business-as-Usual Scenario (Economic Costs)

Chart-1.7
Future Capacity Additions per annum (MWs)

Chart-1.8
Plant Load Factors
Chart-1.9
Share of Each Fuel Class in Total Fuel Requirements

Chart-1.10
Share of Fuel Types in Cumulative Emission of Pollutants
(TSP, SOx, NOx, CO2)
Chart-1.11
Annual CO2 Emissions

Chart-1.12
Total Annual Emission of Local Pollutants
(Thousand Tons)
Chart-1.13
Total Annual Emission of ASH (Million Tons)

Chart-1.14
Reserve Margins 'HOT' and 'COLD'
Prior to the discussion of alternative mitigation strategies and their associated development trajectories, it would be appropriate to trace the Business-as-Usual scenario for a financial cost regime.

2. Business-as-Usual with Financial Costs (BAUF)

Same as BAU scenario, except all costs are evaluated in financial or market prices. Thus, demand forecasts for this scenario remain the same as BAU scenario.

Results

Simulation results for this policy driven scenario are tabulated (Table-A2.1 to Table-A2.20) in Appendix-2.

Tables-A2.1 to A2.4 presents the future capacity additions along the optimal development path under this regime. These additions indicate that total installed capacity increases almost 3.4 times from 6735MWs in 1997 to 23089MWs in 2011, which is a slightly lower than that under BAU scenario. However, with higher capital and O&M costs defined for this scenario, the timing of capacity additions, together with the optimal portfolio of the supply options, are different from that obtained for the economic cost regime. Capacity additions over the 9th, 10th and 11th plan periods are 610MWs, 3130MWs and 8145MWs respectively. Thus, over the planning horizon 7000MWs of coal thermal, 1148MWs of domestic gas thermal, 3330MWs of LNG based, 250MWs of naphtha based plant, 110MWs major hydro project, and 47MWs of renewable capacity additions are envisaged.

With considerable capacity shortage to meet peak and intermediate loads, the major hydro project at Jurala is first inducted into the system. Similar to the BAU scenario, pithead plants at Talcher are preferred over other supply options, followed by pithead plant at Singareni. However, as indicated by the tables-A2.11 and A2.12, both these options are constrained by availability and production build-up of fuels. Although, LNG based open-cycle plant at load centre is added to the system and appears to be the next generation option, this is inducted as reserve in ‘cold’ condition solely to meet the peak guarantee condition and provide the necessary reliability to the system. Gas options are the next preferred alternative, followed by LNG and naphtha. During the early years of the planning horizon fresh wind and mini hydro projects are not added to the system, unlike the BAU scenario. Excepting for fewer capacity additions of the renewable options over the 10th plan period, additions of coal and domestic gas options more or less follow the same trend as BAU scenario. However, during the 11th plan period it is observed that, apart from the domestic coal based capacity additions, substantial gas based generation capacity is added, followed by LNG and naphtha based options. Thus,
gas based open-cycle plants are first added, in place of renewable and LNG based options in BAU scenario, as peaking options, followed by gas combined-cycle plants for meeting base load. Gas options are, however, constrained by the limited and uncertain fuel availability, and thus ultimately supplemented by LNG based combined-cycle and open-cycle plants. LNG combined cycle plants being constrained by the maximum annual build limits, naphtha based supply option is the next preferred alternative as against imported coal for BAU scenario. Under the present assumptions on techno-economic norms, the maximum availability of fuel resources, the maximum build limits and the shape of the load duration curve, it is observed that load centre coal plants are not the optimal selection. Further, in the absence of any explicit imposition of penalty on local pollutants, such as on ash discharge, supply options using washed coal does not appear to be a feasible option either. Capacity additions over the plan periods are depicted in Chart-2.6. This scenario, thus, envisages less of imported fuel options as well as renewable options, whereas more of gas options, naphtha based option and open cycle technologies (for peaking purposes), as compared to the BAU scenario.

The share of various fuel-options in total installed capacity as illustrated in Chart-2.1 shows the predominance of coal based plants over the planning horizon. For the first two plan periods these shares follow similar trends as that under the BAU scenario. In the 11th plan period it is observed that, although the trends are almost similar, the shares of coal (domestic and imported together) and LNG options are relatively lower, while shares of domestic gas and naphtha are relatively higher, in this scenario as against the BAU scenario.

The optimal levels of output produced by the different fuel types at different demand levels for each year are presented, in Tables-A2.5 to A2.7, as shares of fuel types in total load generation in each mode of operation. Coal thermal generation is the main contributor catering to the base load, increasing steadily from 64.4% in 1997 to 76.3% in 2002. Over the 10th and the 11th plans this share fluctuates to reach as high as 81% in 2008 and eventually decline to a low of 60.5% in 2011. Hydro projects also contribute significantly to the base mode, although with hardly any fresh additions this share gradually declines over the plan years with occasional fluctuations. Although shares of naphtha and gas in the base mode are small compared to domestic coal and hydro, it is observed that in this scenario their contributions have been quite steady over the plan years. In fact, naphtha contributions to the base mode over the 10th plan and 11th plan periods are higher than that in the BAU scenario. It may be pointed out that for meeting the base load the shares of coal are lower and shares of naphtha as well as domestic gas higher over the 10th plan, and over the 11th plan the shares of naphtha and hydro are higher, than that in the BAU scenario. Over the 11th plan period LNG based generation in the base mode increases, as in BAU scenario, fast replacing coal thermal generation. Thus, the
relatively higher overall share of hydrocarbon and the relatively lower share of coal generation in base mode generation, as against the BAU scenario, would have a beneficial effect on the environment. It is observed that over the 10th plan period pumped storage demands more from the base mode for pumping water as during this period it is contributing more towards meeting the peak demand compensating for the lower installed wind capacity, relative to the BAU case. Over the 9th and 10th plans hydro primarily contributes to the intermediate mode, with some contribution from the relatively inefficient coal plants as more and more efficient plants get introduced into the system. Relative to BAU scenario contribution to the intermediate mode by hydro plants is higher over the 10th plan in this scenario, since domestic gas has a larger share in base mode in this period and displaces some hydro generation from base to intermediate mode. Over the 11th plan contributions from naphtha and gas in the intermediate mode goes up supplementing, and occasionally replacing, contributions from coal and hydro. The share of coal in the intermediate mode is higher in BAU as against this scenario, having significant environmental implications. These are illustrated in charts-2.3 and 2.4. Chart-2.5 shows that for the first two years it is only wind that is contributing to the peak mode, but thereafter hydro-options emerge and remain as the main contributor to the peak mode. This chart further indicates that over the 9th and 10th plans coal contributes significantly to the peak mode but declines slightly over the 11th plan, when contributions from domestic gas and LNG increases.

Table-A2.8 indicates that total energy generation goes up 3.04 times from 37421.59GWhs in 1997 to 113775.8GWhs in 2011. Coal thermal generation increases from 24549GWhs in 1997 to 70996GWhs in 2011, gas thermal generation goes up from 1721GWhs in 1997 to 22983GWhs in 2011, naphtha thermal generation rises from 1534GWhs in 1997 to 9330GWhs in 2011, and hydro and wind generation registers a moderate increase from 9617GWhs in 1997 to 10467GWhs in 2011. Chart-2.2 depicts the shares of various fuel types in total energy generation, as tabulated in Table-A2.9. Naphtha based generation in this scenario is relatively much higher and coal thermal generation relatively lower than the BAU scenario. Further, gas based generation over the 9th and 10th plans are relatively higher as against BAU scenario. Compared to BAU scenario, in this scenario auxiliary consumption, although follows similar trends, is relatively lower except for the first couple of years in the 11th plan period. It is further observed from the table that, excepting for the terminal years of the 10th plan, future plants under financial cost regime generate less energy at busbar than what future plants generate under BAU scenario. PLFs tabulated in Table-A2.10 and illustrated in Chart-2.7 shows that coal and naphtha, and later LNG based combined cycle plants, are the main base load supply options. Although domestic gas based plants initially operate as base load supply options; they eventually switch roles to become peaking options. The table also indicates that hydro based projects, open cycle LNG plants and wind projects are essentially
peak load supply options. The declining overall PLF is a consequence of changing SLF and has little to do with the overall plant availability factor.

Chart-2.8 illustrating shares of different fuels in total fuel requirements indicate the dominance of domestic coal. On the average, over the planning horizon, coal accounts for more than 85% of the total fuel requirement. Even when LNG accounts for 16.1% of the total fuel requirement, the share of domestic coal remains at 73.6%. However, compared to BAU the shares of naphtha and gas in total fossil fuel requirements are on the average higher and the shares of LNG as well as coal are slightly lower in this scenario.

Table-A2.14 shows that unmet energy for the first two years is same as that under BAU scenario. The build-ups of reserve capacities over the plan periods follow similar patterns as that under the reference scenario. Thus, there is a sudden jump in reserve capacity between the terminal years of the 9th plan and beginning of 10th plan periods. However, beyond this period the overall reserve initially declines and then rises steadily. The overall reserve capacity and reserve capacity set aside in 'cold' condition is lower in this scenario than that under BAU scenario. The spinning reserve requirements in the two scenarios are almost similar. This indicates that more efficient plants with better plant availabilities are operating in the system under the financial cost regime. The reserve capacities are illustrated in Chart-2.13.

The present value economic cost and the levelised average cost of sent-out as obtained for this scenario are Rs387.6billion (includes Rs51.52billion as present value cost of unmet energy) and 1.033Rs/KWh respectively, both of which are lower than the cost prevailing under economic cost regime. However, under the financial cost regime, as a consequence of higher capital and O&M costs, the levelised average cost of future plants at 1.32Rs/KWh is higher than reference scenario.

The environmental consequence of this development scenario is an improvement over that corresponding to the economic cost regime. In absolute terms the overall emissions of various pollutants are enormous, which is a consequence of the predominance of coal thermal generation in total generation of electricity. Tables-A2.15 to A2.18 tabulates the shares of fuel types in total annual emissions of various pollutants. Domestic coal may be solely held responsible for the emissions of TSP, since contributions of the other fuels are insignificant. Compared to the reference scenario, over the 9th and 10th plan periods, TSP emissions in this scenario are generally lower. However, over the 11th plan TSP emissions are almost the same as that of the economic cost regime. Emissions of SOx in this scenario are lower than the reference scenario. Table-A2.16 indicates that the share of naphtha in total SOx emission for this scenario is distinctly higher and that of coal lower relative to the BAU scenario. It is observed that, in case of NOx emissions shares of coal and LNG in total emissions are lower, and share of naphtha distinctly higher, relative to the BAU scenario. However, share of
domestic gas in total emissions of NOX is almost identical to that obtained for the reference scenario. As compared to the economic cost regime, share of naphtha in total emission of CO2 is higher and share of coal as well as LNG is lower for this scenario. Although initially for the first two plan periods share of domestic gas in total CO2 emission is observed to be higher relative to the BAU scenario, this share is almost identical for the 11th plan period.

Table-A2.20 lists the total emission of pollutants per annum. These emissions as illustrated in Charts-2.10 to 2.12 indicate moderated increase over the first two plans and then almost stabilize over the 11th plan. This stabilization is more marked for the local pollutants and as for CO2 the rate of increase falls drastically. Unlike BAU scenario there is no upturn in emission around the terminal years of the 11th plan. Annual TSP emission increases 2.743 times, SOX increases 2.75 times, NOX rises 2.88 times, CO2 grows 3.12 times and ash discharged rises 2.74 times over the planning horizon. Cumulative emissions for the pollutants obtained for this scenario are 1832.5KiloTons of TSP, 5465KiloTons of SOX, 4998.8KiloTons of NOX, 227.3MillTons of Ash, and 835.5MillTons of CO2. Corresponding to cumulative ash discharged total land required for its disposal is estimated to be 1.82thousand hectares. With reference to BAU scenario maximum improvements in emissions are observed for local pollutants (TSP, SOX, NOX, and Ash discharge), especially SOX emission. Shares of the various fuels in cumulative emissions of pollutants are illustrated in Chart-2.9. Table-A2.19 shows that in cumulative emissions although coal is mainly responsible for emission of all the pollutants its share is lower relative to the economic cost regime. Shares of naphtha and domestic gas are relatively higher, whereas share of LNG is relatively lower. However, compared to coal, the contributions of all the other fuels are in fact quite small. In fact even for this relatively improved environmental situation coal alone accounts for 99.6% of cumulative SOX emission, 97.2% of cumulative NOX emission, almost entire TSP emission, and more than 90% of cumulative CO2 emission. Thus, relative to the financial cost regime, power system development within an economic cost regime is marked by about 2% higher present discounted cost as well as levelised average cost (sent-out) and about 3% higher cumulative emission of each local pollutant as well as 1% higher cumulative emission of CO2.

As is clearly evident, the emission patterns of the various pollutants and the shares of fuel types in total emissions are a direct consequence of the generation patterns discussed earlier. Thus, it is due to inter-fuel substitution arising from altered cost situation that would lead to lower emissions of pollutants relative to the reference scenario. Several sensitivities to this scenario are worked out to assess the implications of higher fuel prices. The objective is to examine whether raising fuel prices would actually qualify as an indirect policy instrument for emission reduction. Besides, this is also an attempt to test the robustness of the development trajectories, ceteris paribus, to a rise in fuel price.
Sensitivity to BAUF Scenario

2(a). Variation of BAUF with 25% higher coal prices at source (BAUF1)
2(b). Variation of BAUF with 25% higher LNG prices at regassification point (BAUF2)
2(c). Variation of BAUF with 25% higher indigenous Gas and LNG prices at the source and regassification points respectively (BAUF3)
2(d). Variation of BAUF with 25% higher indigenous Gas prices at source (BAUF4)

Sensitivity Results

The results of these sensitivity analyses are presented as comparative Tables-S2.1 to S2.14 in Appendix-2 (Continued). The simulations of the above cases indicate a small reduction in the emissions of pollutants only for the development path involving higher coal prices. Thus, for higher gas or/and LNG prices the optimal development trajectories are slightly more polluting. However, by and large, the development trajectories are fairly robust, with only minor changes in overall system costs and emissions.

Although the timing of capacity additions are slightly altered, with reference to the BAUF scenario, there are notable changes in total capacity additions over the plan periods for the 25% higher fuel price scenarios. For 25% higher domestic coal prices there is in fact no change on the portfolio of capacity additions over the plan periods. For higher hydrocarbon prices, over the 9th and 10th plan periods there is hardly any change in pattern, except that with higher gas prices no combined cycle gas plants are chosen over the 10th plan. Further, for higher gas or LNG prices more renewable options are envisaged over the 9th and 10th plans. Over the 11th plan period some change in composition of the optimal technology basket are observed for higher hydrocarbon prices. Thus, for higher LNG prices more of gas, naphtha, and imported coal based capacity additions are envisaged; for higher gas and LNG prices together more of naphtha and imported coal based capacity additions are the optimal choice. An interesting observation is that for higher gas prices more of gas based plants and less of LNG capacities are envisaged compared to the BAUF scenario. This may be explained by the fact that gas based plants mostly provide the reserve capacity requirements in ‘cold’ condition, and the larger renewable capacity in this scenario that caters to the peak load substituting for gas in the peak mode. Although over the 11th plan period the renewable capacity additions are lower than BAUF scenario, the total renewable capacity additions over the planning horizon are greater than BAUF scenario. It is observed that for higher LNG, as well as for higher gas and LNG prices together, the total installed capacity over the planning horizon is greater. This implies that in these cases the system is composed of less efficient plants, thus, requiring a larger reserve capacity and particularly so in ‘cold’ condition.
With reference to the pattern of generation it is observed that for higher coal prices there is little variation from BAUF scenario. Whatever little variation is envisaged it is naphtha and hydro plants that replace domestic coal generation to meet the base load, which in turn substitute naphtha and hydro in meeting the intermediate and peak loads. With higher LNG prices it is observed that over the 9th and 10th plans little variation is possible. Over the 11th plan period, however, coal along with gas and naphtha replaces LNG from base mode, and gas as well as naphtha replacing LNG from the intermediate and peak loads. For higher gas prices over the 10th plan little substitution by coal in the base mode as well as by renewable options in the peak and intermediate mode is observed. Over the 11th plan it is mostly LNG replacing domestic gas in the different modes along with the renewable options replacing gas in the peak mode. Finally, for higher domestic gas and LNG prices together it is observed that over the 10th plan it is mostly domestic coal that replaces gas from the base as well as intermediate modes, and renewable options replacing gas over the intermediate and peak modes. Over the 11th plan it is naphtha and imported coal based generation that substitutes gas and LNG from the different modes, relative to the BAUF scenario.

Although not quite significant, inter-modal interfuel substitution is the key to slight improvement in the environmental situation for higher coal prices. Amongst the various pollutants maximum reduction is observed with reference to SO\(_x\) emissions and minimum for TSP and Ash emissions. The shares of fuel types in emissions of pollutants hardly indicate any variation. It is only cumulative emissions that indicate slight improvement in the environmental situation. Since domestic coal is the mainstay of generation and would continue to do so for the next 10-15 years, a 25% rise in coal prices fails to influence interfuel substitution to any great extent is mainly reflected in higher system costs with little improvement in emissions of pollutants. Although, a very large increase in domestic coal prices may make some difference in fuel composition mix, particularly over the 11th plan, it is difficult to predict, a priori, whether there would be any marked improvement in emissions. This is because, notwithstanding interfuel substitution in favour of hydrocarbons, contributions from imported coal may in fact increase consequent upon an improvement in the competitiveness of its relative price. However, it is certain that any increase in coal prices would be reflected in considerable rise in system costs as well as levelised average costs.

On the other hand, higher prices for LNG and/or gas lead to a worsening of environmental situation. Similar to the higher coal price case, any change in environmental situation finds its genesis in interfuel inter-modal substitution of fuels. The worst possible situation arises from higher LNG and gas prices together since interfuel substitution ensues from the outset and would increase considerably over the 11th plan. Although, it is difficult to
unambiguously claim that a rise in LNG price is worse than a rise in domestic gas price, with reference to \( \text{SO}_x \) and \( \text{CO}_2 \) emissions higher LNG prices are in fact more polluting than higher gas prices. With reference to the costs it is observed that with 25% higher price of hydrocarbons the overall system cost increases but only marginally. However, it may be unambiguously claimed that for very large price increases of hydrocarbons the environmental situation would register formidable deterioration accompanied by significant rise in costs.

*Thus, from the sensitivity analyses it may be conjectured that, under the present set of assumptions and norms, a very substantial rise in the price of gas and/or LNG (much more than 25%) would adversely affect power sector development in Andhra Pradesh. Further, it may be deduced that, notwithstanding improvements in environmental situation for 25% higher domestic coal prices, raising just domestic coal prices, within the present state of affairs, may not unambiguously qualify as an indirect policy instrument for reducing emissions from the power sector in Andhra Pradesh.*

Having analyzed power sector development for the Business-as-Usual scenario, it would be quite insightful to assess the changes in optimal development trajectories of the power sector under alternative emission mitigation strategies. These mitigation strategies may be independently viewed as alternative development strategies for the power sector with different economic and environmental implications. The alternative mitigation, which are also alternative development strategies, considered for this study are discussed below along with the simulation results, which, as already mentioned, are discussed with reference to the Business-as-Usual scenario for the economic price regime.
CHARTS for Business-as-Usual Scenario (Financial Costs)

Chart-2.1
Share of Fuel Types in Total Installed Capacity

Chart-2.2
Share of Each Fuel Type in Total Energy Generation
CHARTS for Business-as-Usual Scenario (Financial Costs)

Chart-2.3
Share of Fuel Type in Base Mode Generation

Chart-2.4
Share of Each fuel Types in Intermediate Mode Generation
Chart-2.7
Plant Load Factors

Chart-2.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-2.9
Share of Fuel Types in Cumulative Emission of Pollutants (TSP, SOx, NOx, CO2)

Chart-2.10
Annual CO2 Emissions
Chart-2.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-2.12
Total Annual Emission of ASH
(Million Tons)
Chart-2.13
Reserve Margins-'HOT' and 'COLD'
B. Market Based Instruments / Incentives

As discussed in chapter-1, in order to avoid the difficulties associated with the valuation of power sector externalities, control costs are generally used as a proxy for environmental damages and are included in the planning for power system development. The rationale usually furnished in support of this approach is that since the regulators have appropriately weighted the social costs of pollution control when enacting emission standards, it follows then that the marginal costs of pollution control should equal the marginal benefits of reducing pollution. However, this rationale does not hold water since standards are mostly adopted without adequate knowledge of the damage costs. The policy of charging a penalty for the act of polluting and damaging the environment is meant to influence the decision process by affecting the costs and benefits of the alternative actions, internalize externalities and enable efficient resource allocation.

In the BAU scenario only control costs and other quantifiable environmental costs were considered, such as expenses on mitigation or control instruments, other mitigation and adaptation expenses, social expenses on rehabilitation and resettlements, etc. Thus, BAU scenario does not include externalities arising from the uncontrolled and fugitive emissions of the local and global pollutants. This scenario and its variations attempt to internalize some of the externalities due to the emissions within the planning framework through the adoption and use of carbon tax on CO₂ emissions and/or charging a penalty for the damage caused by fugitive local pollutants (SOx, NOx, TSP). There are several reasons for choosing power sector development under a carbon tax regime as the main scenario under this category of mitigation strategies:

- Coal being the mainstay of generation along with the massive cumulative CO₂ emission envisaged, as evident from the analyses of the previous scenarios, it would be appropriate to look into mitigation strategies that might influence interfuel substitution and enable major environmental benefits;
- CO₂ emissions, along with other Greenhouse Gases, is at the core of a raging global environmental policy debate;
- Being constantly urged to join the international efforts towards global environmental mitigation efforts, should India concede to the demand of reducing and stabilizing CO₂ emissions, it would be appropriate to look into the implications of imposing a carbon tax;
- Several economy-energy-environment studies have attempted to assess the implications of different carbon taxes. Thus, it is easier to obtain estimates of carbon taxes than damage costs of local pollutants. Most of these studies base their estimation on the costs of reforestation to replace equivalent quantity of carbon, rather than any estimate of the actual
damages likely to result from global warming. Consequently, from the range of estimates found in the literature, a high and a low carbon tax is chosen for this study. The high carbon tax is assumed for the main scenario, with a simulation for the low carbon tax providing the sensitivity.

Since the most immediate pressure to control environmental degradation would come from local conditions, variations to the above mitigation strategy are also simulated where estimates of damage costs of local pollutants are included. Although it is extremely difficult to evaluate damage costs, the question this scenario seeks to answer is that whether the optimal least cost expansion plan changes if some damage costs are included and to what extent. In this attempt to internalize environmental externalities due to local pollutants through the adoption of damage costs a separate independent valuation approach is avoided. Following Meier and Munasinghe (1994), this study relies on studies done elsewhere to arrive at estimates of damage costs of local pollutants. These estimates mostly rely on mortality and morbidity effects or health costs. However, appropriate adjustments have to be made to these estimates to make them applicable to the Indian situation, since it is quite unlikely that the damage costs in India based on jury damage awards, health insurance premiums, lost earnings and hospital expenses would be as high as these estimates. Consequently, with reference to the California Energy Commission estimates of damage costs (Meier and Munasinghe, 1995), this scenario accepts and uses 10% of these estimates as damage costs based on the differences in per capita income of the nations. (Alternatively purchasing power parity dollars could have been used to arrive at the damage costs. This is avoided to overcome the complexities associated with the use of two different dollar exchange rates.) The present approach of using uniform damage costs is based on the underlying assumption of uniform impact of emission dispersion. This essentially implies that the emission impact, i.e. physical impact and its monetisation, is independent of the location of the plant. Ideally the damage costs for local pollutants should be source and site specific to take account of the non-uniformity of impacts and, hence, ambient air qualities. However, in the absence of any other conventional better way of internalizing externalities the above procedure is chosen, so as not to neglect and introduce accountability of the harmful impacts of local pollutants completely.
3. **Carbon Tax Scenario (CTAX)**

In this scenario a high carbon tax of Rs.900 per ton of CO₂ emission is imposed to control CO₂ emissions from 2002 onwards. All other assumptions, norms and supply options are taken to be the same as that of the BAU scenario.

**Results**

The simulation results for this hypothetical scenario are tabulated in Appendix-3 Table-A3.1 to Table-A3.20.

The optimal capacity addition schedule and the total installed capacity over the planning horizon are tabulated in Table-A3.1 to Table-A3.4. Since carbon tax is imposed from 2002 onwards, the capacity additions over the 9th plan period are almost the same as that under BAU scenario. However, over the 10th and 11th plan periods some major changes are observed since the use of carbon tax influences the substitution of more carbon intensive fuels with less carbon intensive fuels. *Thus, unlike the BAU scenario, in this scenario it is observed that gas and LNG based combined cycle plants are preferred over coal thermal plants, thereby adding substantial hydrocarbon based technologies to the system over the planning horizon. Thus, over the 10th plan period domestic gas based combined cycle plant is first preferred followed by LNG based combined cycle plants when domestic gas availability poses to be a binding constraint* (Tables-A3.11 and A3.12). It is further observed that a LNG based load centre open cycle plant is added to the system only to ensure the reserve capacity requirement of the system. However, constrained by the phased availability of LNG (Tables-A3.11 and A3.12), some Talcher coal based pithead plants are also envisaged over the 10th plan. Over the 11th plan it is observed that, with increase in the availability of LNG, more combined cycle LNG plants are added to the system. However, to account for infrastructural and other bottlenecks, since a maximum overall build limit is assumed, pithead Talcher coal thermal plants appear to be the next preferred alternative when LNG based combined cycle plants reach this limit. Further constrained by the coal availability from Talcher (Tables-A3.11 and A3.12), pithead Singareni coal thermal plants are inducted into the system. Over the 11th plan, substantial open cycle gas and LNG plants are added to the system to mainly cater to the peak load and also provide the necessary reserve margin. *Thus, coal thermal plants, using Talcher and Singareni coals at the pithead, in that order of preference, are optimally chosen only when the assumed phased availability of LNG acts as a binding constraint. Over the planning horizon almost maximum penetration of renewable technologies is envisaged, only constrained by the assumed maximum annual build limits or maximum build limits of LNG based plants are reached.* However, load centre plants using domestic and imported coal, plants using washed coal and naphtha based combined cycle plants are not preferred at all. Chart-3.6 depicts the pattern of capacity additions over the planning periods. Thus, capacity additions envisaged over the 9th, 10th and
11th plans are 619MWs, 2851MWs, and 8575MWs respectively. This shows that capacity additions over the 9th and 10th plans are lower than the BAU scenario and over the 11th plan it is relatively higher.

It is observed from Table-A3.4 that the total installed capacity increases 3.45 times from 6735MWs in 1997 to 23249MWs in 2011. The optimal development trajectory under carbon tax regime indicates 3.53 times rise in coal thermal capacity, which is lower than that under BAU scenario. However, a 24.56 times increase in gas and LNG based capacity is much higher than the BAU scenario. Thus, over the planning horizon capacity additions envisaged are 6500MWs of coal thermal plants, 1316MWs of domestic gas based plants (most of which are open cycle plants), 4050MWs of LNG based plants (most of which are combined cycle plants), 110MW major hydro project at Jurala, and 69MWs of mini hydel and wind based projects. Chart-3.1 shows that the share of the coal thermal plants in total installed capacity declines over the 10th plan but rises again over the 11th plan period. Moreover, the share of LNG in the total installed capacity over the 10th and 11th plan periods and share of domestic gas over the 11th plan rises considerably. It is observed that the share of naphtha in total installed capacity is lower under the carbon tax regime. This is because total installed capacity over the planning horizon is higher under this scenario relative to the BAU scenario. But for minor fluctuations over the 10th and 11th plan periods, the shares of hydro and wind in total installed capacity remains more or less the same as that of BAU over the planning horizon. Thus, the optimal capacity addition schedule under a carbon tax regime indicates more of LNG and domestic gas based generation options along with more of renewable projects and less of coal (domestic and imported) thermal generation options relative to the BAU scenario.

The optimal levels of output produced by the different fuel types at different demand levels for each year are presented, in Tables-A3.5 to A3.7, as shares of fuel types in total load generation in each mode of operation. As presented in Table-A3.5, chart-3.3 shows that in the base mode over the 9th plan there is very little change over BAU scenario except that share of coal is slightly higher and share of hydro slightly lower in this scenario. However, over the 10th plan it is observed that share of coal in base mode generation falls considerably from 55.7% to 49.4% being replaced primarily by contributions from naphtha and LNG based plants. Share of hydro in the base mode over this period is also higher in this scenario relative to BAU scenario. Consequently, over the 10th plan it is observed that pumped storage demands more from the base mode to contribute more towards meeting the peak demand during this period relative to the BAU case. However, it is observed that share of hydro gradually declines as the share of LNG goes up. Finally, over the 11th plan period it is observed that the share of coal thermal goes up, although still lower than that envisaged for the BAU scenario. Shares of LNG and naphtha declines over this period, although compared to BAU scenario share of naphtha is still higher and LNG almost the same. Further shares of domestic gas and hydel in the base mode rapidly
declines over this period. Chart-3.4 depicts that hydro primarily contributes to the intermediate mode, with domestic gas making contributions over the 10th and 11th plan periods. Although to a quite limited extent, wind makes contributions towards meeting the base load. However, share of coal in the intermediate mode is much lower than the BAU scenario. Chart-3.5 shows that hydro is the main contributor to the peak mode. However, coal also makes some contributions to the peak mode. This share of coal is higher than the BAU scenario over the 9th and 10th plans and relatively lower over the 11th plan period. It is observed that over the 10th and 11th plans shares of LNG and domestic gas gradually goes up, with a slight decline in share of LNG over the terminal years of the 11th plan.

Table-A3.8 presents energy generation over the plan years and indicates a 3.04 times rise in gross energy generation from 37421.59GWhs in 1997 to 113754.04GWhs in 2011. However, compared to BAU scenario, gross energy generations over the 10th and 11th plan periods are lower under carbon tax regime implying lower auxiliary losses. Energy generation at busbar by future plants is relatively lower than BAU scenario because, notwithstanding substantial contributions from LNG based plants in the base mode, domestic gas based plants contribute less to the base mode and more to the peak and intermediate modes. Besides, in this scenario, naphtha based existing plants make significant contribution to the base mode. Table-A3.9 indicates that although share of coal in total energy generation is significantly lower than the BAU scenario, coal still continues to be the mainstay of generation. However, as depicted in chart-3.2, share coal drops over the 10th plan and the initial years of the 11th plan to reach a low 48.4% and thereafter rises to reach 62% by 2011. Over this same period LNG based generation increases first and then declines slightly. With the imposition of the carbon tax from 2002 onwards it is observed that initially share of naphtha in total generation increases displacing coal based generation; but after LNG plants are inducted into the system their share gradually declines. However, relative to BAU scenario shares of LNG and naphtha in total generation are significantly higher and the share of coal generation significantly lower. These observations are endorsed by the total requirements of the various fuels presented in Table-A3.11. Shares of the various fuels in total fuel requirements as tabulated in Table-A3.13 and illustrated in chart-3.8 indicates that coal, notwithstanding significant decline over the 10th plan, constitutes the lions share amongst all the fuels in total fuel requirement. However, share of coal, although when minimum is 60.5% of the total fuel requirement, compared to BAU scenario is much lower. Whereas relative to BAU scenario shares of hydrocarbons in total fuel requirements are higher, with LNG reaching as high as 27.5%. Thus, carbon tax influences the fuel mix in total installed capacity and generation by substituting more carbon intensive fuels with the less carbon intensive fuels.
PLFs of the plants presented in Table-A3.10 and depicted in chart-3.7 indicates very high level of utilization of LNG and naphtha based capacity, and low level of utilization of Talcher coal based capacity relative to the BAU scenario, particularly through the 10th and 11th plan periods. As against the BAU scenario coal thermal plant using Singareni coal also record low plant utilization under the carbon tax regime over the 10th and 11th plan periods. A rapidly declining PLF for the gas based plants from the latter half of the 10th plan through the 11th plan indicates that gas based supply options are primarily used as peaking options and substantial portions of the installed gas based capacity are underutilized. Although this trend is similar to the BAU scenario, the extent of decline in PLF is much more severe for the carbon tax scenario. Thus, the PLFs of the domestic coal based plants indicate considerable underutilization of capacity as compared to the BAU case. Reserve capacity requirement as compared to the BAU scenario indicates lower overall reserve capacity over the 9th and 10th plans, but goes up to exceed that of the reference scenario over the 11th plan. It is further observed that, under the carbon tax scenario, spinning reserve or reserve capacity in 'hot' condition is lower, thereby making the system less resilient to sudden outages. Chart-3.13 shows that reserve capacity in ‘cold’ condition gradually declines over the 10th plan and then stabilizes, but takes an upward turn towards the terminal years of the 11th plan. It is further observed that relative to BAU scenario over the 9th and 10th plans installed capacity margin over peak load is lower but exceeds over the 11th plan period.

The change in the pattern of development that is observed under carbon tax regime as against the BAU scenario has important cost and environmental implications. It is observed that the present discounted cost and levelised average cost (sent-out) for the optimal development under carbon tax regime is higher than the BAU scenario. Thus, the present discounted value at Rs.568.3billion is 1.432 times higher and the levelised average cost at 1.51Rs/KWh is 1.43 times higher than the BAU scenario. The higher cost is a consequence of higher fuel prices with hydrocarbons replacing domestic coal and also because of the carbon tax. It is further observed that although the levelised average capital and O&M costs for the future plants are lower than BAU scenario; substantially higher levelised average fuel cost for the future plants that makes the overall levelised average cost of future plants to exceed that for the reference case. Thus, levelised average cost for future plants at 1.40Rs/KWh is 1.12 times higher than the BAU case. The fact that this development paradigm is oriented towards hydrocarbon fuels makes the system, particularly with reference to costs, quite vulnerable to fuel prices in the international market, foreign exchange availability, balance of payment situation, and a horde of other economic and political factors. However, the tradeoff with higher cost situation is an improved environmental situation arising from the reduction in emissions.
Implementation of a carbon tax reduces emission by promoting a change in the fuel mix, wherein coal is replaced by hydrocarbons and to a lesser extent by renewable options. Table-A3.15 to Table-A3.18 presents the share of fuel types in the annual emissions of the various pollutants. Similar to the BAU scenario coal is mainly responsible for the emission of TSP, with the difference that in this scenario it is exclusively domestic coal that is to be held responsible. It is observed that coal and naphtha are responsible for SO\textsubscript{x} emissions. Over the 9\textsuperscript{th} plan period, when no carbon tax is imposed on the system, the shares of fuels in total emission almost replicates the BAU case. Relative to BAU case, from the 10\textsuperscript{th} plan onwards it is observed that the share of coal in total SO\textsubscript{x} emission is much lower and that of naphtha much higher excepting for the last year of the planning horizon. However, coal continues to account for the maximum share in the total emission of SO\textsubscript{x}. With the proliferation of hydrocarbon based supply options from the 10\textsuperscript{th} plan and coal thermal getting displaced in total generation, the share of coal in total NO\textsubscript{x} emission declines whereas that of LNG, domestic gas and naphtha increases. Because of increased generation by coal for the terminal years of the planning horizon, their share in total NO\textsubscript{x} emission goes up once again. However, compared to the BAU case, the share of coal is lower and shares of hydrocarbons are higher in total NO\textsubscript{x} emission. Major changes from the BAU case are observed with reference to CO\textsubscript{2} emissions. It is observed that not only is the total emission lower relative to the BAU case but the shares of various fuels in the total emission different. The most significant rise in share is observed for LNG and naphtha over the 10\textsuperscript{th} and the 11\textsuperscript{th} plan periods. The changing pattern of emissions and responsibilities of the various fuels in total emissions are a direct consequence of the changing pattern of generation.

Table-A3.20 presents total annual emission of pollutants for the optimal development path for this carbon tax scenario. It is observed that notwithstanding substantial increases in the total emissions of TSP, SO\textsubscript{x}, NO\textsubscript{x}, CO\textsubscript{2}, and ash over the planning horizon, the emissions are significantly lower over the 10\textsuperscript{th} and 11\textsuperscript{th} plans than the BAU case. In the pre-tax period it is observed that there is little change in emissions from the BAU case. However, in the period between years 2002 and 2008 it is observed that TSP emissions are 15-40\% lower, SO\textsubscript{x} emissions are 15-39\% lower, NO\textsubscript{x} emissions are 14-32\% less, CO\textsubscript{2} emissions are 8-21\% less, and ash discharges are 15-39\% lower than the BAU case. Further, consequent upon substantially lower discharge of ash, less land is required for ash disposal relative to the BAU scenario. However, as already discussed, as coal based generation increases over the last couple of years of the planning horizon, power system development proceeds with a steep rise in emission of pollutants with a rapid drop in emission reduction. These are further indicated in chart-3.10 to chart-3.12. These depictions clearly indicate that till about first half of the 11\textsuperscript{th} plan emissions increase at a fairly moderate rate with a sudden steep rise in the rate thereafter, with the most pronounced rise in rates being observed for SO\textsubscript{x}, NO\textsubscript{x}, and ash. As against the BAU scenario, cumulative emission of TSP at 1545.4KiloTons is 17.8\% less, SO\textsubscript{x} at 4614.1KiloTons is 18\% less,
NO\textsubscript{x} at 4367.7KiloTons is 15.2\% less, CO\textsubscript{2} at 763.7MillTons is 9.7\% less and cumulative ash discharge at 191.6MillTons is 17.9\% less. The shares of fuel types in cumulative emission of pollutants, as tabulated in Table-A3.19 and depicted in chart-3.9, shows that domestic coal is primarily responsible for the emission of pollutants. However, relative to the BAU case it is observed that share of hydrocarbons in the emission of pollutants, particularly CO\textsubscript{2} and SO\textsubscript{x}, are higher and that of coal lower.

Thus, relative to the BAU scenario, power system development within a carbon tax regime is marked by about 43\% higher present discounted cost as well as levelised average cost (sent-out) and about 15-18\% lower cumulative emission of each local pollutant as well as 10\% lower cumulative emission of CO\textsubscript{2}. It may be noted that although the policy of introducing a carbon tax is aimed at reducing CO\textsubscript{2} emission would also substantially reduce the emission of local pollutants. In fact it is observed from the above discussion that consequent upon the imposition of a carbon tax local pollutants are mitigated to a greater extent than CO\textsubscript{2} emission. Thus, it is observed that a Pigouvian Tax on pollutants by affecting the costs of the polluting fuels increases the penetration level of the less polluting generation options including renewable options.

Sensitivity to CTAX Scenario

3(a). Variation of CTAX with lower tax (CTAX1)

In this scenario a low carbon tax of Rs.300 per ton of CO\textsubscript{2} emission is imposed to control CO\textsubscript{2} emissions from 2002 onwards.

3(b). Variation of CTAX with damage cost on local pollutants (CLPTAX)

This case assumes imposition of damage costs of local pollutants along with the high carbon tax. Thus, Carbon tax used is a high Rs.900 per ton of CO\textsubscript{2} emission, damage cost for NO\textsubscript{x} emission is assumed Rs.50690 per ton of NO\textsubscript{x} emission, for SO\textsubscript{x} it is Rs. 25987 per ton of emission, and for TSP it is Rs. 201670 per ton of TSP emission. However, percentage reduction of emissions attributed to various emission control measures, whose costs are already included in the capital and operating costs of the generation options as environmental control costs, are accounted for. Thus, 99\% removal of TSP is considered due to ESP for all thermal plants, and 60\% removal of NO\textsubscript{x} for all liquid and gaseous hydrocarbon plants attributable to low NO\textsubscript{x} burners. The penalties on local pollutants along with the carbon tax are imposed from 2002 onwards.

3(c). Variation of CTAX with only damage cost on local pollutants and no carbon tax (LPTAX)

In this scenario no carbon tax is imposed to control CO\textsubscript{2} emissions, but all externalities caused by fugitive local pollutants are internalized through the use of damage costs from 2002 onwards.
Sensitivity Results

The results to the variants are tabulated in Appendix-3 (Continued) as comparative Table-S3.1 to Table-S3.14 for the terminal plan years.

Result for 3(a):

Unlike the high carbon tax scenario, for the low tax scenario very little change in the capacity addition schedule and pattern of generation is observed relative to the BAU scenario. Domestic coal based capacity additions are added to the system by the same extent, but slightly more of hydrocarbon based plants are added to the system. However, imported coal based plants are not added to the system over the 11th plan period, and instead domestic and imported gas based plants are preferred. Besides, more renewable options are added over the development trajectory. Relative to the BAU scenario, in the generation too the less carbon intensive fuels, such as gas, naphtha and LNG, replace more carbon intensive fuels like domestic and imported coal over the 10th and 11th plans.

However, notwithstanding interfuel substitution in capacity additions and generation in the various modes of operation, compared to the high tax regime or CTAX scenario the extent of substitution is much lower. Thus, for this low tax regime share of coal in the generation at base and intermediate modes are much higher, and shares of naphtha, LNG as well as domestic gas lower as compared to the CTAX case. Consequently the extent of emission mitigation is much lower than the high carbon tax scenario. Further, relative to CTAX regime gross energy generation is also higher, implying higher auxiliary losses and hence economically, financially and environmentally less attractive. It is observed that relative to BAU for this scenario a 15% higher cost leads to 2-3% lower TSP, SOx, NOx, cumulative emission and ash discharge as well as 1.4% lower cumulative emission of CO2. Whereas, an approximately 25% higher cost because of higher carbon tax leads to a 14-16% lower emission of local pollutants and about 8-9% lower emission of CO2. It may be noted, however, that although higher carbon taxes lead to greater emission reductions but the incremental emission reductions are lower. Compared to the CTAX regime in this scenario the present discounted value cost and levelised average cost are lower. Although generation by future plants are higher and has a positive influence in lowering cost, it is environmentally more polluting since a considerable share of this future plant generation is attributed to coal based generation. Thus, a comparative analysis of low and high carbon tax scenarios indicate that a high carbon tax although environmentally more attractive is achieved only at a substantial rise in cost. Whereas a low carbon tax is not attractive because the cost increases are much more than the emission reduction envisaged.
Result for 3(b):

When local pollutants are directly penalized along with charging a high carbon tax major changes are observed along the optimal development path. Capacity addition schedule indicates that over the plans significantly large hydrocarbon based capacity additions and less of coal based supply options relative to the CTAX scenario. It is observed that the environmentally benign and less polluting supply options are initially added and towards the last couple of years of the planning horizon some coal plants are added when resource availability limits and build limits (annual or overall) are reached. Thus, instead of coal plant being added over the 9th plan, naphtha plant and renewable options are added to the system to fulfill the capacity shortage, load requirement and reliability levels. Hydro plant is added later in the system over the 10th plan period. Renewable options are added to the system over the planning horizon to their maximum possible potential, excepting for the last two years of the planning period when less of wind options are added. Amongst the fossil fuel options, gas based combined cycle plants are first preferred followed by LNG and naphtha based combined cycle plants. Hydrocarbon based capacity additions are observed over the 10th plan and the early years of the 11th plan. Domestic gas and LNG based open cycle plants are added to the system over the 11th plan to meet the peaking requirements as well as satisfy reliability condition. Over the last couple of years of the planning horizon Talcher pithead coal plants are added. Finally, constrained by the availability of Talcher coal some Singareni pithead coal plants are also added to the system. It is observed that, because of the penalty imposed on the fugitive emissions of local pollutants, all coal plants (amounting to 5000MWs) added to the system use washed coal both at Talcher and Singareni.

Over the plan years the capacity addition schedule indicates 916MWs of domestic gas, 4350MWs of LNG and 1250MWs of naphtha based supply options. Moreover, 69MWs of renewable options are picked up along with the major hydro project at Jurala. Total installed capacity of 22899MWs at the end of the planning horizon is lower than that for CTAX scenario. It is further observed that the installed capacity margin over the peak load and reserve capacities (both in ‘hot’ and ‘cold’ conditions) are lower than CTAX scenario. This implies that the system comprises of more efficient plants with greater plant availability than the high carbon tax scenario without penalty on local pollutants. Further, in this scenario spinning reserve in ‘hot’ condition gradually increases over the 10th and 11th plan periods and the reserve capacity in ‘cold’ condition gradually declines through the 10th plan to stabilize over the 11th plan with a minor upturn towards the terminal years. Auxiliary consumption for this scenario is also lower than the CTAX scenario.
It is observed that in the base mode over the 9th plan there is very little change with slightly higher share of naphtha towards the terminal years. However, over the 10th plan it is observed that consequent upon imposition of the penalty domestic coal is displaced by naphtha and supported by domestic gas and LNG. Over the 11th plan, besides higher share of naphtha, it is observed that shares of LNG and hydro are also higher. In the intermediate mode also hydro, gas and naphtha displaces domestic coal, with hydro emerging as the primary contributor. In the peak mode the shares of coal over the 10th and 11th plan periods are higher, along with higher share of wind, relative to the CTA scenario. Hydro, however, continues to account for the major share amongst the various options contributing to the peak mode. Notwithstanding significant contributions by hydrocarbon based open cycle plants, the shares of hydrocarbons in general are relatively lower than CTA scenario in the peak mode. Thus, inter-modal interfuel substitution arising from the additional imposition of penalty on local pollutants is reflected in higher share of hydrocarbons in total generation, over the 10th and 11th plans primarily, and the preference for washed coal amongst coal based generation.

From the terminal years of the 9th plan through the 10th plan and the initial years of the 11th plan, overall PLF is relatively lower since considerable capacity of coal based supply options in commission are optimally underutilized. PLFs of hydrocarbon based options are relatively higher, and that of plants using unwashed coal (particularly Talcher coal) are relatively lower than the CTA scenario. It is noted that the fuel requirements per annum indicate that gas, naphtha and LNG requirements fully exhaust fuel availability over the 10th and 11th plan periods.

The optimal pattern of development under the influence of direct penalties and Pigouvian tax scheme indicates an optimal generation fuel mix that leads to a substantial reduction in emission of all pollutants. It may be further noted that the additional imposition of penalties on local pollutants not only reduces emission of local pollutants but also leads to a considerable reduction in emission of CO₂. Although tax and penalties are imposed from the 10th plan, it is observed that emissions are lower relative to the CTA scenario from 1999 since naphtha based plant instead of coal plant is inducted into the system. Rapid emission reduction across all the pollutants are observed from the year taxes and penalties are imposed. Relative to the CTA scenario, cumulative emissions are about 21% lower for TSP, 19% lower for SOₓ, 16% lower for NOₓ, 8% lower for CO₂, and 21% lower for ash discharge and land for ash disposal. Moreover, it should be noted that relative to CTA scenario the share of hydrocarbons in the total annual emissions of the various pollutants, over the 10th and 11th plans in particular, are higher and that of coal lower.

However, costs associated with this scenario relative to the CTA case are significantly higher. Thus, the present discounted cost and the levelised average cost (sent-out) are approximately 22% higher for this scenario relative to the CTA scenario. Further, relative to the
CTAX case, notwithstanding lower capital and O&M costs for the future plants, the overall levelised average cost for future plants are higher since the levelised average fuel cost for future plants are higher. Thus, there appears a substantial tradeoff between cost and emission reduction. Further, it may be noted that percentage increase in cost over CTAX does not enable same percentage reduction in emissions. It may be noted that the extent of reduction possible in the CLPTAX case is higher than in the CTAX case, but only at a much higher cost. It is the increased use of hydrocarbon in CLPTAX case relative to the CTAX scenario that raises the cost as well as brings about an increased emission reduction. However, this scenario with only penalties charged on local pollutants emerges as the superior strategy within this category of strategies.

Result for 3(c):

Notable amongst all the sensitivities in this category is the outcome associated with this case where only penalties on local pollutants are imposed and no carbon tax is imposed. The optimal outcome indicates almost similar capacity addition schedule as that of the previous sensitivity (CLPTAX) where carbon tax was included along with the penalty on local pollutants. Unlike CLPTAX case but similar to the CTAX case, it is observed that before penalties are imposed a Talcher pithead coal plant is added along with the major hydro project to overcome the capacity shortfall, meet the load and energy requirements, and ensure the required reliability of the system. However, over the 10th and 11th plan periods, when the penalties are imposed, the optimal capacity addition schedule indicates predominance of hydrocarbon based options, with some washed domestic coal based plants getting inducted towards the terminal years of the 11th plan. Domestic washed coal based plants are inducted into the system when utilization of hydrocarbons in the generation of electricity exhausts their availability. Notwithstanding their high fuel cost, LNG based combined cycle plants at load centre appear to be chosen when the maximum annual build limits of LNG based plants at the regassification point are reached. With a level playing field provided to the renewable options, by taxing the fossil fuels for polluting the environment, substantial penetration of renewable technology is observed over the 10th and 11th plan periods. It may be noted that significantly large number of domestic gas and LNG based open cycle plants are added to the system of the 11th plan period. Thus, compared to CTAX case less of coal thermal and gas plants along with more of LNG and naphtha based plants are added over the planning horizon. The optimal capacity addition schedule indicates 5000MWs of coal plants (includes 4500MWs of washed coal based plants), 716MWs of gas based plants, 4580MWs LNG based technology, 1250MWs of naphtha plants, 110MWs Jurala hydro project and 69MWs of renewable options. The total installed capacity of 22929MWs at the end of the 11th plan is lower than the CTAX case.
It is observed that mainly naphtha replaces coal in the various modes of operation. Compared to CTAX the share of naphtha in total generation is considerably higher and that of coal lower. The optimal trajectory indicates that shares of gas and hydro, relative to the CTAX case, although slightly on the higher side, by and large remain the same. The pattern of generation is very similar to the CLPTAX case, with shares of naphtha and gas slightly higher over the 10th plan. Displacement of coal by naphtha in the generation is most pronounced over the 10th plan as also indicated by the fuel requirements per annum. For this scenario gross energy generation, which increases from 37421.59GWhs to 113156.90GWhs, is lower than that for the CTAX case, implying less of auxiliary losses. With lower installed capacity, the installed capacity margin over peak demand is also lower.

The changing pattern of emission, relative to the CTAX case, is a consequence of the altered generation pattern and fuel mix. Greater reductions of emissions are achieved, relative to the CTAX case, mainly due to greater substitution of coal by hydrocarbons in generation. Shares of fuel types in the total annual emissions of pollutants exhibit a lower share of coal and higher share of naphtha, domestic gas and LNG. TSP and SOx and ash reductions are achieved through increased use of hydrocarbons over the 10th and 11th plans as well as use of washed coal towards the terminal years of the 11th plan. Reductions in NOx and CO2 are mainly a consequence of displacement and replacement of coal from the various modes of operation by hydrocarbons. Amongst the hydrocarbons it is mainly the use of naphtha that is responsible for increased reduction of emissions relative to the CTAX case. Maximum reductions of emissions are achieved over the 10th plan followed by relatively lower reductions over the 11th plans. Increased penetration of renewable technologies is also instrumental to the reductions in emissions. It is observed that, relative to the CTAX scenario, cumulative emissions of TSP are 16.5% lower, SOx are 14.8% lower, NOx are 12.3% lower, CO2 are 6.6% lower and cumulative ash discharge is 16.6% lower. Moreover, relative to the CTAX case, the present discounted cost and the levelised average cost is 3.2% lower for this scenario. Thus, with reference to the BAU scenario, imposition of penalties on local pollutants although raises present discounted and levelised average costs by 38.6%, would also yield reduction of cumulative emission of TSP by 31.5%, SOx by 30.2%, NOx by 25.6%, CO2 by 15.6% and cumulative ash discharge by 31.5%. It is, however, observed that the levelised average cost of future plants is higher mainly on account of higher fuel costs. These estimates obtained for the given set of assumptions, including those for the taxes and penalties, illustrates the need to explicitly account for the externalities due to fugitive emissions at the planning stage of the power sector.

Drawing from the above analyses it may be argued that although, prima facie, it may appear that the Private Power Policy of the government supporting, promoting and committing naphtha based plants is non-optimal, but it is observed that naphtha emerges as the preferred fuel option when environmental damages are penalized. It is further observed, in the above case, that policies aimed at reducing local pollutants would not only reduce emission of local pollutants but also substantively reduce global pollutants, and may be much more than a tax on
emission of global pollutant. The above analyses indicates that, under the present assumptions on penalty charged for emission of local pollutants, the discounted system costs are lower in the local pollutant penalty case than under the high carbon tax regime. Taxing emissions or charging a penalty for polluting may be effective if monitoring emissions and environmental damages is difficult as well as expensive, which are quite common in developing countries like India. Moreover, by taxing environmentally hazardous fossil fuels the rate and level of penetration of the renewable technologies would considerably improve. However, in a predominantly fossil fuel based power system, taxing emissions may prove to be onerous as it would get reflected in higher cost of generation. The caveat, however, to this strategy is that in judging the effectiveness of a policy instrument it is not only important to look at the cost effectiveness, efficiency and extent of achieving desired emission targets, but also assess whether it is consistent with national priorities. Thus, as in the above cases, excessive dependence of the power sector development on hydrocarbons, along with a limited support from renewable technologies and hydro projects, has important implications for the energy security and BOP situation of the economy.
CHARTS for Carbon Tax Scenario

Chart-3.3
Share of Fuel Type in Base Mode Generation

Chart-3.4
Share of Each fuel Types in Intermediate Mode Generation
Chart-3.7
Plant Load Factors

Chart-3.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-3.9
Share of Fuel Types in Cumulative Emission of Pollutants (TSP, SOx, NOx, CO2)

Chart-3.10
Annual CO2 Emissions
Chart-3.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-3.12
Total Annual Emission of ASH
(Million Tons)
Chart-3.13
Reserve Margins-'HOT' and 'COLD'

Years

Reserve Margins (MWs)

-1000
-500
0
500
1000
1500
2000
2500


SPIN. RESRV
RM COLD
C. Promotion of Technological Options

Substantial mitigation of emissions is possible through technological options influencing interfuel substitution, efficiency improvements and conservation. These technological options exist both on the supply side and the demand side of the power sector. The existing literature advocates that proactive effort in promoting renewable technologies may bring about substantial environmental benefits. Efficiency improvements on the supply side, which include T&D loss reduction and rehabilitation of T&D network, by bringing down the load and energy requirements at busbar and, hence, generation, would yield considerable improvements in the quality of supply and environmental benefits. Demand side measures through efficiency improvements, load management and conservation on the demand side would substantially bring down the load and energy requirements having obvious economic and environmental implications. Further, introduction of the advanced and clean coal technologies in generation planning and capacity expansion in a predominantly coal based power system may prove to be environmentally quite attractive. However, it needs to be acknowledged that achieving the full mitigation potential of technological options would depend on, *inter alia*, future cost reductions, financing, technology transfers and institutional arrangements. The above mentioned technological options, on the supply and demand sides, are explicitly considered as separate policy driven scenarios along with their variations and the development paths simulated and assessed as against the *reference scenario* (BAU).

4. *Renewables Scenario (REN)*

Although there is a fairly large potential for renewable energy in Andhra Pradesh, the achievement till date is a small percentage of the total potential. Several factors that may be categorized as technological, institutional, financial, and infrastructural are responsible for this under-utilization. In the BAU scenario maximum potential for the future evolution of renewable technologies is assumed in this study taking historical penetration into account. This scenario assumes modest increases in the level of market penetration and availability of renewable options. The underlying assumption is that the present impediments to the realization of the true potential of the renewable options would be considerably surmounted over the planning horizon. Thus, the upper bounds on the availability of renewable options are increased to reflect proactive initiatives towards increased promotion of these options. It is assumed that the maximum additions each year would be doubled over that of the BAU scenario for both the wind and mini hydel options. It is further assumed that over the planning horizon at the most 210MWs of wind options can be harnessed and mini-hydel options may be utilized to the extent of 170MW, (*IRP for Andhra Pradesh*, however, hoped to harness these options to the same
extent latest by 1999/2000). All other assumptions for the scenario are taken to be the same as that of the Business-as-Usual scenario.

Results

The simulation results for this hypothetical policy driven scenario are tabulated in Appendix-4 Table-A4.1 to Table-A4.20.

The simulation results indicate very small changes from that of the reference or BAU scenario. Total installed capacity is observed to increase approximately 3.43 times from 6735MWs in 1997 to 23092MWs in 2011, which is only 13MWs less than that of the BAU scenario. Thus, capacity additions envisaged over the 9th, 10th and 11th plans are 630MWs, 3152MWs and 8106MWs respectively. This shows that capacity added over the first two plans in this scenario exceeds that in the BAU case, but is less than the reference scenario for the 11th plan period. Thus, with reference to BAU case, higher penetration of renewable technology over the plan periods displaces some of the conventional generation option over the 11th plan period. It is observed that over the planning horizon 7630MWs of coal thermal plants (including 630MWs of imported coal based plants) are added, along with 232MWs of gas thermal plants, 3790MWs of LNG plants (including 800MWs of open cycle plants), 110MWs of hydro project at Jurala, and 126MWs of renewable options.

The optimal type, size and timing of future capacity additions are tabulated in Table-A4.1 to Table-A4.4. Comparison with the BAU case indicates very similar pattern of capacity expansion over the 9th and 10th plans with more of renewable options being added to the system. It is observed that the fuel types follow similar preferred sequence. Thus, over the planning horizon, apart from the hydro project and other renewable technologies, Talcher coal based options are first inducted followed by Singareni coal based options into the system. Constrained by the availability of coal, domestic gas and LNG based plants are introduced, followed by imported coal based when either or both fuel availability constraints and annual build limits of plants become binding. These are clearly observable from the study of these tables in association with the fuel availability and requirement constraints presented in Tables-A4.11-A4.12. However, some discernible changes are observed over the 11th plan period where additions of open cycle gas plants used for meeting peak load are lower and those of renewable options, open cycle LNG plants and imported coal based plants higher relative to the BAU case. It may be further noticed that an additional combined cycle gas plant is also inducted into the system over this period. Chart-4.1 illustrating the shares of fuel types in total installed capacity shows that although by and large this is similar to the BAU case, the minor changes noted over the 11th plan are lower share of domestic gas and slightly higher share of hydro, wind, LNG and also imported coal. Imported coal is only added in the terminal year of the planning horizon. However, domestic coal based plants at load centre, washed coal based plants and
naphtha based plants are not chosen along the optimal development path. Chart-4.6 illustrates the pattern of capacity additions over the plan periods.

Outputs generated by the different plant types at different load levels are presented in Table-A4.5 to Table-A4.7. Chart-1.3 shows that pattern of generation in the base mode are very similar to that in the BAU case. The similarity with the BAU case over the 9th and the 10th plan periods is maximum, with occasionally higher shares of coal and lower shares of hydro over the 10th plan. For some of the years over the 11th plan shares of coal in the base mode are slightly lower and that of hydro higher. It is coal and hydro that is mainly contributing to the base mode, although the share of hydro gradually declines over the years. Share of coal declines over the 11th plan when LNG displaces coal in the base mode. Imported coal, as compared to the BAU scenario, makes lower contribution to the base mode. Chart-4.4 shows that hydro mainly contributes to the intermediate mode, with coal making contributions when more and more efficient plants are brought into the system and the less efficient plants pushed up the LDC. Contributions by coal to the intermediate mode follows almost similar pattern over the 9th plan as that of the BAU case, but over the 10th and 11th plan periods it is observed that for some years coal replaces hydro and for some other years hydro replaces coal. Also it is observed that contributions by gas and naphtha to the intermediate mode for some years are higher than the BAU case. Chart-4.5 shows contributions by plant types to the peak mode, and indicates the predominance of hydro. Contributions by coal and naphtha to the peak mode are almost similar to that of the BAU case, but shares of gas are distinctly lower. Thus, domestic gas is replaced by wind, hydro and to some extent by other fossil fuels as coal and LNG. An interesting observation is that, particularly over the 10th plan period, pumped storage demands less from the base mode since it contributes less towards meeting the peak demand, relative to the BAU case.

Table-A4.8 presents the gross generation of electricity and indicates a 3.04 times increase from 37421.6GWhs in 1997 to 113894.5GWhs in 2011. It is observed as compared to the BAU case gross energy generation is slightly lower in this scenario, indicating lower auxiliary losses having important financial implications. Further, generation by future plants in this scenario is distinctly more than that of the BAU scenario. Table-A4.9 listing the shares of each fuel types in the total energy generation, also depicted in chart-4.2, indicates that compared to BAU case share of coal (both domestic and imported), particularly over the 10th and 11th plans are lower and that of hydro and LNG are slightly higher. It is further observed that shares of gas in the total generation towards the terminal years of the planning horizon are slightly higher, indicating a shift of domestic gas away from the peak mode and towards the base mode generation. Although coal thermal accounts for the maximum share in the total generation, but towards the terminal years of the planning horizon this share declines being replaced by a rapidly growing LNG based generation. Notable, as in the BAU case, is the
declining share of hydro in total generation. Increased penetration of renewable technology thus primarily displaces domestic gas from the peak mode, and also influence substitution of imported coal from the base mode by other fossil fuel options as well as hydro.

This is also to some extent evident from the PLFs presented in Table-A4.10 and illustrated in chart-4.7. Comparing these PLFs with those obtained for the BAU case shows lower PLFs for imported coal based capacity indicating their under-utilization. It is also observed that towards the terminal years of the planning horizon, greater utilization of combined cycle plants is indicated by their higher PLF. This may be also attributed to the lower installed capacity of gas thermal plants because of the absence of open cycle gas based plants. PLFs of the wind options are also observed to be slightly higher over the 10th and 11th plan periods. The overall PLF is observed to be very similar to that of the BAU case, gradually declining over the planning horizon being primarily influenced by the declining SLF of the system. The reserve capacity requirements, tabulated in Table-A4.14, show that the reserve capacity in 'cold condition' exceeds that of the BAU case, along with almost similar reserves in 'hot condition'. The overall reserve capacities (i.e. excesses of utilizable capacity over peak demand) are higher in this scenario. However, over the terminal years of the planning horizon a slight rise in the spinning reserve capacity is observed over that of the BAU case. The slightly lower reserve capacity in 'cold condition' is because of greater penetration of renewable options in this scenario. Further, towards the terminal years of the planning horizon spinning reserves are higher because of more imported coal and LNG based capacity in the system.

It is observed that the present discounted value of the system cost at Rs.396.7 billion is very close to that obtained for the BAU case. The levelised average cost at 1.057 Rs/KWh is also almost the same as that of the BAU case. Even the levelised average cost for the future plants are same as that for the BAU case. Thus, with respect to cost there is hardly any difference between the two scenarios.

Shares of fuels in total fuel requirement, as tabulated in Table-A4.13 and depicted in chart-4.8, indicates that the share of coal is highest accounting for about 90% over the 9th and 10th plans. Over the 11th plan this share declines as the share of LNG in total fuel requirement increases, but continues to account for the maximum share. Compared to coal the shares of gas and naphtha are quite small. These shares are very similar to those observed for the BAU case. Thus, a moderate increase in the penetration of renewable options makes little difference to the pattern and extent of fuels burnt.

The fact that fuels burnt for generation is almost identical, hence there is very little reduction in emissions that is possible. Table-A4.15 to Table-A4.18 presents the shares of fuel types in total emissions of pollutants. Coal thus continues to account for the maximum share in the emission of TSP. However, compared to BAU, in this scenario domestic coal is solely
responsible except for the last year of the planning horizon when imported coal makes some
contribution. With reference to \( \text{SO}_x \) emission also coal accounts for the maximum share with
imported coal contributing very little in the last year. Share of naphtha in the total emission of
\( \text{SO}_x \) is same as that in the BAU case. Similarly, it is observed that the shares of different fuels
contributing towards \( \text{NO}_x \) and \( \text{CO}_2 \) emissions are almost identical to that of the BAU case with
the exception that the share of imported coal is lower. Thus, in terms of shares of fuels in
cumulative emissions it is observed from Table-A4.19, also illustrated in Chart-4.9, that the
shares are almost the same as that under the BAU case with the share of imported coal
distinctly lower. Total annual emissions of the pollutants are tabulated in Table-A4.20 and
illustrated in Charts-4.10 to 4.12. These indicate that TSP rises 2.762 times from
65.31KiloTons in 1997 to 180.39KiloTons in 2011, \( \text{SO}_x \) increases 2.842 times from
194.42KiloTons in 1997 to 552.57KiloTons in 2011, \( \text{NO}_x \) rises 2.994 times from
175.80KiloTons in 1997 to 526.4KiloTons, \( \text{CO}_2 \) rises 3.15 times from 28479.88KiloTons in
1997 to 89720.92KiloTons in 2011, and Ash discharge increases 2.786 times from
8.10MillTons in 1997 to 22.37MillTons in 2011. Thus, in the final years of the planning
horizon, when there are substantial capacities of renewable options installed in the system, the
reduction in pollutants over the BAU case are about 0.3-0.4%. Improvements in cumulative
emissions of the pollutants for this scenario are less than 0.1% over that of the BAU case.

Thus, increased penetration of renewable options by displacing domestic gas from the
peak mode and other fossil fuel options from the various modes, effectively influences fossil fuel
options (both domestic coal and hydrocarbons) to substitute for and replace imported coal in
generation. Although this may have important economic implications, but only little
improvements in the cost and environmental situation is possible with this modest increases in
penetration of renewable technology.

Sensitivity to REN Scenario

4(a) Variation of REN Scenario as even higher harnessing of potential (RENHI)

This is a variation of the REN scenario, with higher renewable options assumed to be
available for harnessing and are hoped to be actually realized consequent upon further
improvements in the infrastructural, institutional, economic and financial impediments
presently prevailing. This scenario is a variation of the previous scenario in terms of the
maximum annual build limits of the renewable options. Thus, annual build limits assumed are
6MWs of small hydel and 4MWs of wind farms over the 9th plan; 15MWs of small hydel and
20MWs of wind option over the 10th plan; and 21MWs of small hydel and 24MWs of wind
options over the 11th plan. The limits on cumulative additions are, however, same in both the
scenarios, i.e. wind options can at the most harness 210MWs and mini hydel options may be
utilized to the extent of 170MW over the planning horizon.
Sensitivity Results

The results to the variants are tabulated in Appendix-4 (Continued) as comparative Table-S4.1 to Table-S4.14 for the terminal plan years.

An assessment of the output obtained for this sensitivity indicates that by allowing for further increases in the penetration of renewable technology yields little improvement in the environmental situation. The cumulative emissions for this scenario indicate that excepting for TSP and Ash discharged, which are about 0.03% higher, the improvement in the emissions of all other pollutants over the REN case are between 0.001% - 0.1%. In fact, evaluation of the present discounted emissions of local pollutants indicates that a further attempt at increasing the penetration of renewable technology not only leads to a worsening of TSP emissions but also SOx emissions as well as. The environmental fallout is a direct consequence of the pattern and extent of power sector development under this policy regime. In the present case it may be observed that with further increase in the penetration of renewable options capacity additions of domestic coal based plants remains the same. Further, if domestic gas and LNG are taken together as a single hydrocarbon fuel option then combined cycle and open cycle capacity additions in the high renewable case remains the same as that of the moderately high renewable case. However, at the margin, with higher capacity additions of renewable options, less of imported coal based capacity gets added. An important observation is that amongst the renewable options mini-hydel projects are always more preferred to wind projects under the present assumptions on costs and techno-economic norms. It is observed that share of gas, LNG and imported coal in total energy generation are distinctly lower as compared to the REN case, and the shares of hydro and wind are higher. It is only the slightly higher share of domestic coal in the base mode that makes the difference. Although there is little or somewhat insignificant change in the environmental status, but relative to the REN case the present discounted value and levelised average costs of generation are slightly lower.

Thus, the above analyses for grid connected renewable options reveal that increased involvement of renewable options does not necessarily reduce the influence of domestic coal based generation, but essentially replaces hydrocarbons and/or imported coal based options from the peak and intermediate modes of operation in the system. Although from an economic point of view and taking note of the national priorities this may be quite beneficial, but the ultimate effect on the environment is either insignificant or evokes an element of uncertainty. Policies that reduce the contribution of domestic coal in a system, where coal is cheap and abundant, would favourably affect the environment. Under the existing technological characteristics and given their dependence on meteorological conditions and site specific nature, even if it is assumed that there are no impediments to penetration of technology, grid connected renewable options may have a somewhat insignificant, and/or at times adverse, impact on the environment. Although it may be somewhat audacious to make such a strong
general statement, it would not be incorrect to say that this observation may hold for similar power systems. Notwithstanding these limitations as a mitigation option, increased penetration of renewable options has obvious benefits for a resource scarce power sector facing rapidly growing load demand. Thus, renewable options are quite relevant to meet the peak load requirement and bridge the demand-supply gap. The revelation from the above analyses that mini-hydel projects are more preferred and easily inducted than wind options have important implications for a state like Andhra Pradesh. As already discussed in chapter-4, the potential for wind option in Andhra Pradesh is somewhat limited and uncertain, whereas mini-hydel projects have considerable potential. However, implementation of mini-hydel projects is quite limited due to myriad problems. The fact that mini-hydel projects of the irrigation canal drop types are concentrated in exactly the same months as those in which the agricultural demand is at its peak, they may be effectively used for meeting the peak demand during irrigation months. Finally, although beyond the scope of this exercise, but drawing upon the findings of some of the existing studies, it may be conjectured that renewable options are noted for their capability to be used as decentralized option for catering to the demand at minimum loss of energy. Adoption of renewable technologies as decentralized options may have significant economic and environmental benefits arising from reduction of demand and losses that the utility has to satisfy.
Chart-4.1
Share of Fuel Types in Total Installed Capacity

Chart-4.2
Share of Each Fuel Type in Total Energy Generation
Chart-4.5
Share of Each Fuel Types in Peak Mode Generation

Chart-4.6
Capacity Additions over the Plan Periods (MWs)
Chart-4.9
Share of Fuel Types in Cumulative Emission of Pollutants
(TSP, SOx, NOx, CO2)

Chart-4.10
Annual CO2 Emissions
Chart-4.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-4.12
Total Annual Emission of ASH
(Million Tons)
Chart-4.13
Reserve Margins-'HOT' and 'COLD'

Years

Reserve Margins (MWs)
-1000 -500 0 500 1000 1500 2000 2500

1997 1999 2001 2003 2005 2007 2009 2011

--- SPIN. RESRV ---
--- RM COLD ---
5. *Clean Coal Technology Scenario (CCT1)*

Although pre-combustion clean coal technology (CCT) like coal beneficiation is also a possible mitigation option on the supply side, but in view of the directives and repeated notifications of the government they are included as a regular fuel choice in all the scenarios. Further, the popular post-combustion mitigation options, such as ESPs, which are already part of any project to meet the stipulations of ambient standards, are also included in every scenario. Thus, this technology promotion scenario refers to the introduction and promotion of new and advanced coal utilization technologies, such as Atmospheric Fluidized Bed Combustion (AFBC) and Integrated Gassification Combined Cycle (IGCC), as generation options along with the other supply options. IGCC and AFBC technologies are in principle *in situ* mitigation options that reduce emissions through efficient utilization and combustion of fuels. Although, *prima facie*, it may appear that with the abundance of cheap low sulphur domestic coal these options may be somewhat redundant, however it would be more appropriate to explicitly assess the optimal outcome from simulating the scenario involving CCTs included in the set of supply options. In this scenario, thus, supply options include load centre as well as pithead IGCC and AFBC plants using domestic unwashed coal along with the technologies considered in the BAU Scenario. The techno-economic norms and costs for these technologies are discussed in chapter-6 along with a description of the features of these technologies. Since the costs for these CCTs (capital and O&M costs), as discussed in chapter-6, include those due to ESP installations, TSP emission reductions by 99% are assumed for these technologies. Further, as already mentioned in chapter-6, it is assumed that technological design ensures reduction of NOx by 75% and SOx by 90% in IGCC, and remove NOx by 65% as well as SOx by 80% in the AFBC plants.

**Results**

Simulation results for this hypothetical policy driven scenario are tabulated (Table-A5.1 to Table-A5.20) in Appendix-4.

The optimal development path for this scenario indicates total installed capacity to increase 3.47 times from 6735MWs in 1997 to 23375MWs in 2011, which is an overall 270MWs higher than the BAU case. The optimal capacity expansion plan over the respective plan periods indicates additions of 619MWs in the 9th plan, 3217MWs in the 10th plan and 8335MWs in the 11th plan. The optimal composition of the capacity expansion comprises of 7500MWs of coal thermal (including 1000MWs of IGCC at Talcher pithead), 716MWs of gas thermal, 3790MWs of LNG based capacities, 110MW hydro project at Jurala and 55MWs of
renewable projects. Thus, relative to the BAU case the optimal composition shows higher coal thermal and LNG based capacities and less of renewable technologies.

The optimal capacity addition schedules and installed capacities are presented in Table-A5.1 through Table-A5.4. It may be noted that, although only 1000MWs of IGCC plants at Talcher pithead are inducted into the system in the terminal year of the 11th plan period, some major inter-temporal changes and adjustments in capacity additions are observed along the least cost development path, compared to the BAU case. The sequence of expansion follows almost similar pattern as that of the BAU case. Because of the huge peaking capacity shortage alongside energy shortages, the major hydro project at Jurala and some mini hydro projects emerge as the first choice along with coal thermal plants at Talcher pithead. Constrained by the production build-ups at Talcher, coal plants at Singareni pithead is the next preferred option. However, further constrained by the availability from Singareni, domestic gas based combined cycle is the next preferred alternative. Availability of domestic gas to the southern region is quite limited and thus constraints the domestic gas based expansion. Consequently, LNG based combined cycle plants at regassification points emerges as the next best option. It is further observed that during the terminal year of the planning horizon with substantial energy as well as peak demand, and LNG based combined cycle plants reaching annual build limits, coal thermal plant at Singareni pithead and IGCC plants at Talcher pithead are inducted into the system. Renewable options are regularly inducted into the system as peaking plants, with a clear preference for mini hydro projects. Further, over the 11th plan period when the peaking demand rises sharply, it is observed that gas (domestic and LNG) based open cycle plants are added to meet the peak load requirements as well as ensure reliability of the system. It may be noted that, notwithstanding restrictions on the availability of domestic resources and LNG based capacity reaching annual build limits, imported coal based plants are not selected. Instead efficient IGCC plants using domestic coal are inducted into the system to be operated as base load plants, with some inefficient plants being operated only at their minimum loading level. Moreover, relative to the BAU case, less of wind based options and more of hydrocarbon (LNG plants) options are added to the system. It is also observed that although domestic gas based combined cycle plant is inducted, but compared to the BAU case it is added over the 11th plan period instead of the 10th plan period. Similar to the BAU case, it is observed that load centre plants using domestic coal and washed-coal based plants are not optimally chosen. The capacity additions over the plan periods are depicted in Chart-5.6. Requirements and maximum availability of fuel resources are tabulated in Tables-A5.11 and A5.12. Share of the fuel types in total installed capacity are presented in Table-A5.4 and illustrated in Chart-5.1. The trends can be seen to be very much similar to the BAU case, where coal thermal takes the lions' share and followed by hydro projects. It is only the share of LNG
based option that is observed to increase rapidly from the second half of the 10th plan through the 11th plan period. It may be noted that LNG based open cycle plants added to the system during the 10th plan are not used for generation but to ensure the minimum guarantee condition or reliability of the system.

Outputs produced by different plants at different load levels are presented in Table-A5.5 through Table-5.7. Chart-5.3 illustrating Table-A5.5 indicates that domestic coal mainly contributes to the base mode, followed by hydro over the first two plans and LNG over the final plan period. It is observed that over the 9th plan with the commissioning of substantial committed coal based capacity and also introduction of fresh capacity from 1999, share of coal in meeting the base demand increases rapidly and remains quite stable with minor fluctuations over the 10th plan period. Towards the early years of the 11th plan this share rises, but declines gradually over the latter half of this plan period, being mainly replaced by LNG based generation. It is observed that share of hydro and naphtha in meeting the base load gradually declines over the plan periods. Domestic gas makes a very small but almost steady contribution to the base mode. The most notable is the rapid increase in the share of LNG in meeting the base load over the 11th plan period. *Little variation from the BAU case is observed in the base mode generation, with the exception of the absence of imported coal, slightly higher share of domestic coal and slightly lower share of hydro. It is further observed that relative to the BAU case in the base mode over the 11th plan share of LNG and naphtha are slightly higher for some of the years.* Chart-5.4 illustrating Table-A5.6 indicates that hydro mainly contributes to the intermediate mode. Contribution by coal thermal to the intermediate mode increases sharply during the 11th plan period, and in the terminal year of planning horizon only coal thermal contributes to this mode. *However, compared to the BAU case, in this scenario contribution to the intermediate mode by coal thermal are lower and that by hydro higher.* Chart-5.5 depicting Table-A5.7 indicates that hydro mainly contributes to the peak mode. For the initial two years when no new plants are added by assumption, it is wind option that only contributes to the peak mode. It is observed that over the latter half of the 9th plan coal makes some contribution along with gas to the peak mode and continues to contribute over the 10th plan and increases gradually over the 11th plan period. Naphtha also supplements hydro and coal over the 10th and 11th plan periods in the peak mode, although mainly over the 10th plan period. It is further observed that over the 11th plan period LNG and domestic gas contributes significantly to the peak mode. In fact the share of LNG is observed to increase over the 11th plan period. Although wind along with mini hydel makes a regular and significant contribution to the peak mode and also to the intermediate mode, their relative shares are quite small. *Compared to the BAU case, in this scenario share of wind and domestic gas is lower and that of LNG is higher in the peak mode. It may be noted that over the 10th plan period supply at busbar in the base mode is higher*
than the BAU case implying that demand by pumped storage in this period for the present scenario is higher. This arises because of the low penetration of wind option used for meeting peak demand in this scenario over the first two plan periods.

Table-A5.8 gives the optimal energy generation over the plan years. Gross energy generation for this scenario increases 3.04 times from 37421.59GWhs in 1997 to 113882.42GWhs in 2011. Compared to the BAU case, gross energy generation in this scenario is higher over the 10th plan period through the first half of the 11th plan period and falls through the latter half of the 11th plan. Higher gross energy generation implies higher auxiliary consumption and a lower energy generation means less energy is required for auxiliary consumption. Thus, the pattern of energy generation in this scenario relative to the BAU case implies that although initially the system was dominated by relatively less efficient plants, but over the latter years of the planning horizon the system evolves into a fairly efficient system with lower auxiliary losses. Another notable observation is that annual energy generation at busbar by future plants is lower relative to the BAU case, implying that in this scenario it is the existing and committed plants that are utilized much more than in the BAU case. The existing and committed plants being mainly coal based have serious implications for the environmental fallout of this development trajectory.

The share of fuel types in annual energy generation, tabulated in Table-A5.9 and illustrated in Chart-5.2, indicates domestic coal to be the mainstay in energy generation over the entire planning horizon. Its is observed that after an initial dip in coal generation during the 9th plan, the share rises and remain fairly stable over the 10th plan and rising slightly over the first couple of years of the 11th plan. However, the share declines gradually over the 11th plan period as coal generation gets replaced and displaced by LNG based generation. Over the first two plans hydro makes substantial contribution and supplements domestic coal based generation. Since compared to fossil fuel based options very little hydro options are added over the planning horizon, so it is observed that the share of hydro in total energy generation steadily declines over the planning horizon. Naphtha and domestic gas makes a small but fairly steady contribution in terms of energy, although over the 11th plan periods these shares decline mainly because of the increasing share of the LNG in total generation. Notable is the rapid increase in the share of LNG in total energy generation over the 11th plan period. Relative to the BAU case it is observed that the share of domestic coal in total energy generation is higher over the 10th and 11th plan periods. Share of naphtha is also higher over some years of the 11th plan period. It is the relatively higher share of coal and naphtha, and the lower share of wind option, in total generation, as compared to the BAU scenario, that would be reflected in worsening of the environmental situation.

Chart-5.7 illustrating the PLFs of various fuel types tabulated in Table-A5.10 indicates the high capacity utilization of domestic coal based plants, particularly those using Talcher coal. However, over the 11th plan period PLFs for these decline indicating under
capacity utilization. Naphtha plants with higher utilization over the 9th plan, falls in utilization over the subsequent plans only to increase once again for the terminal years of the planning horizon. Considerable under utilization of domestic gas based plants are observed over the 11th plan period. Plants using LNG at regassification points have a fairly high PLF, whereas LNG plants at load centre that are used mainly for peaking have low PLFs. **Compared to BAU it is observed that the PLF of wind is lower, and PLF of naphtha plants over the last couple of years of the planning horizon are higher in this scenario.** Reserve capacities for this scenario presented in Table-A5.14 indicate that over the first two plans lower reserve capacity is required to ensure system reliability as compared to the BAU case. However, over the 11th plan the overall reserve capacity is higher excepting for a couple of years. This table further indicates that reserve capacity in hot condition although similar to BAU case for the first two plan periods, is distinctly lower over the 11th plan for this scenario (excepting terminal year of the planning horizon). This implies that, relative to the BAU case, starting from a situation where the standby reserve capacity was relatively lower the system becomes more capital intensive as reserve capacity in ‘cold’ condition becomes relatively higher. The reserve capacities in ‘hot’ and ‘cold’ conditions are depicted in Chart-5.13.

It is observed that the present discounted value of the system cost at Rs.396.8 billion is very close to that obtained for the BAU case. The levelised average cost at 1.057 Rs/KWh is also almost the same as that of the BAU case. Even the levelised average cost for the future plants are same as that for the BAU case. The higher levelised average capital cost of future plants is balanced by lower levelised average fuel cost of future plants. Thus, with respect to cost there is hardly any difference between the two scenarios.

From Table-A5.11 it is observed that relative to the BAU case over the latter half of the 10th plan through the 11th plan period domestic gas requirement is lower, naphtha requirement is higher and coal requirement from Singareni is also higher in this scenario. Table-A5.13 gives the share of each fuel in total fuel requirement and is illustrated in Chart-5.8. These indicate almost similar pattern as that of the BAU case, except that the share of domestic coal and naphtha is slightly higher.

Shares of fuels in the total annual emission of pollutants are presented in Table-A5.15 through Table-A5.18. These shares for TSP and SOx are observed to be very similar to those in the BAU case. It is observed however that in the context of annual NOx emissions share of domestic coal is higher and shares of domestic gas as well as LNG lower than in the BAU case, particularly over the 10th and 11th plan periods, although the trends are somewhat similar. With reference to annual CO2 emission it is observed that, relative to BAU case, in this scenario shares of domestic coal, gas and LNG for the first two plans are almost same, but over the 11th plan these shares are slightly higher. Table-A5.19 presents the shares of fuels in cumulative
emission of pollutants, which are illustrated in Chart-5.9. Compared to the BAU case it is observed that share of coal in the cumulative emission of pollutants is higher, share of naphtha in cumulative emission of CO₂ higher, and share of gas (domestic and LNG) in the cumulative emission of NOₓ lower.

Table-A5.20 presents the annual emission of pollutants that are depicted in Charts-5.10 through Chart-5.12. It is observed that the pattern of annual emission of NOₓ over the planning horizon is quite different from the BAU case, although those of TSP, Ash, SOₓ and CO₂ are quite similar. Along this optimal trajectory TSP is observed to grow 2.743 times, SOₓ rises 2.745 times, NOₓ rises 4.188 times, CO₂ grows 3.102 times, and Ash discharge increases 2.743 times. It may be noted that the rise in all the pollutants except NOₓ is lower than that observed for the BAU case. However, the extent of rise between the terminal years of the planning horizon actually understates the annual emissions, because the emissions in the terminal year of the final plan are significantly lower influenced by the IGCC technology. An important observation is that in this scenario NOₓ emission exceeds SOₓ emission except for the first two years of the planning horizon, unlike all the other scenarios discussed thus far. It is also observed that over the 10th plan there is a very steep rise in the emission of NOₓ, before stabilizing at a very high level over the 11th plan period. The cumulative emissions for this development trajectory indicates benefits due to improvement in cumulative CO₂ emission and worsening of local environmental situation since the cumulative emission of SOₓ and NOₓ are 1.152 and 1.31 times higher respectively, relative to the BAU case. Higher cumulative emission of local pollutants indicate that pollution over the early years of the planning horizon are higher, since SOₓ emission over 11th plan is relatively lower as compared to BAU case. The present discounted emission of local pollutants indicates that the present discounted emission of NOₓ in this scenario is 23% higher than the BAU case, but for SOₓ it is lower. Hence, it is the higher emission of NOₓ that renders this development trajectory unattractive. Thus, consequent upon the implicit objective of optimizing the overall system cost, optimal induction of CCTs as supply options, in the terminal year, through interfuel and inter-modal substitution of generation options adjusts in a manner that worsens the environmental situation for the early years of the planning horizon. Emissions of local pollutants are thus preponed along the development trajectory much before the CCTs are actually inducted into the system. In fact higher emission of NOₓ almost over the entire planning horizon emerges as a major threat to the productivity, health and welfare. Therefore, it is suspect whether at the present technological status and costs, introduction of CCTs while planning for the power sector is a viable alternative, notwithstanding the environmental improvements possible with their commissioning.

However, a caveat to this line of argument is that the manner in which CCTs are considered here fail to fully reflect their true economic, commercial and environmental advantages, particularly for a predominantly coal based power system so intensely dependant on cheap, abundant and poor quality coal. Although from the above results it appears that
AFBC plants are not viable, the fact remains that they are the most promising of all the advanced coal utilization technologies, particularly in the Indian situation. Amongst the advantages of AFBC plants the most attractive is its ability to burn coal of all grades, biomass refuse, and wastes from coal cleaning. Thus, in a power system so immensely dependent on coal and with coal washing gradually getting introduced, enormous wastes are inevitable at the mines and washeries. These along with the proliferation of huge capacities at the pithead would critically affect the ambience and sustainability of these sites. It is with reference to these that the AFBC plants have a very special role in the power sector development. In view of these, it might be more useful to consider AFBC as purely mitigation technologies instead of treating it as a supply option at the decision making stage.

To sum up, then, at the present cost and technological assumptions, the optimal development path indicates induction of CCTs not earlier than the terminal year of the 11th plan period. If the optimal trajectory of this policy driven scenario is accepted, then it is observed that optimal expansion and generation over the planning horizon yields worsening of the environmental situation, without any noticeable improvement in the cost situation, with reference to the BAU case. This calls for increased proactive efforts in R&D efforts to further bring down the costs of CCTs and make them much more competitive and commercially viable, so as to optimally induct them in the power system over the 9th and the 10th plan periods. In order to reap the obvious environmental and efficiency benefits of CCTs it would be appropriate to treat them as possible mitigation options, instead of supply options, and take locational planning into account. If, washery rejects from coal beneficiation plants are taken into account, along with the wastes from coal mines, and environmental fallout arising from the proliferation of pithead plants are considered, then CCTs may emerge as an optimal choice.
Chart-5.1
Share of Fuel Types in Total Installed Capacity

Chart-5.2
Share of Each Fuel Type in Total Energy Generation
Chart-5.3
Share of Fuel Type in Base Mode Generation

Chart-5.4
Share of Each fuel Types in Intermediate Mode Generation
CHARTS for Clean Coal Technology Scenario

Chart-5.5
Share of Each Fuel Types in Peak Mode Generation

Chart-5.6
Capacity Additions over the Plan Periods (MWs)
CHARTS for Clean Coal Technology Scenario

Chart-5.7
Plant Load Factors

Chart-5.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-5.9
Share of Fuel Types in Cumulative Emission of Pollutants
(TSP, SOx, NOx, CO2)

Chart-5.10
Annual CO2 Emissions
CHARTS for Clean Coal Technology Scenario

Chart-5.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-5.12
Total Annual Emission of ASH
(Million Tons)
Chart-5.13
Reserve Margins 'HOT' and 'COLD'

- SPIN. RESRV
- RM COLD
6. **T&D Reform Scenario (TDREF)**

As already discussed in chapter-5, recent endeavours to identifying least cost power development strategies indicates an emphasis on energy services as an index of development, where effective capacity additions through improvements in efficiency and conservation is as important as expansion of system capacity. Thus, a comprehensive approach to planning for the power system subsumes improvement in efficiency of energy use and quality of power supply. Such an approach to power sector planning is not only attractive on economic and financial considerations, but also has significant environmental benefits associated with it. This is the underlying rationale behind the construction and evaluation of this and the next policy-driven scenario.

T&D losses have considerably increased over the years and there lies ample scope for bringing it down substantially. As discussed in chapters-4&5, these losses can be broken down into largely unavoidable technical losses, arising from, *inter alia*, the periodic build up and collapsing of electromagnetic fields and the resistive heating up of wires, and the avoidable commercial losses or losses due to theft and pilferage. Although technical T&D losses can be reduced only to a certain level, there remains substantial scope for reducing the commercial losses. However, bringing down commercial losses might not reduce the demand but bring the illegal consumption within the net of revenue earnings of the Board. Whether bringing down commercial losses would actually reduce consumption depends upon the elasticity of consumption. The present status of the power sector indicates that there is enough scope to bring down the technical losses. These improvements may be achieved through greater involvement of the Board towards elimination of the present bottlenecks; increasing the share of expenses on T&D reform, rehabilitation and modernization; improving the efficiency of operation and proper maintenance; reduction in low tension lines; and proper grid management.

Thus, this scenario assumes further reduction of T&D losses over that considered for the BAU scenario, and the demand at busbar is adjusted accordingly. The losses are assumed to reduce by 0.5% initially between 1996/97 and 1998/99, and thereafter reduce by 1% every year to reach 12% in 2005/06. However, beyond 2005/06 it is assumed that losses may be reduced by 0.5% to reach 9% in 2010/11. In the initial years loss reduction is slow and then picks up because it takes some time before the benefits of T&D reforms are realized. The loss reduction falls after an initial increase because beyond a certain level loss reduction becomes more and more difficult. In view of the fact that with an improvement in the T&D losses considerable peak demand saving will take place, it is assumed that the SLF would decline over the years at a much slower rate than what it is considered for the BAU scenario. Thus, it is assumed that SLF would come down slowly from 76.1% in 1996 to 70% in 2011. This would
yield fresh forecasts for energy and peak demands for electricity, as presented in chapter-5, and consequently LDCs are constructed afresh for each year of the planning period with the same LDC parameters presented in chapter-6. The development plan corresponding to this demand will indicate the impacts of improvement in T&D losses. These load levels along with the annual energy forecasts for this scenario are tabulated in Table-A6.1 of Appendix-6. These forecasts indicate that the energy demand grows at 5%, 7.3% and 7.8% per annum over the 9th, 10th and 11th plan periods respectively. Thus, energy demand increases 2.64 times from 37599GWhs in 1996 to 99418.55GWhs in 2011, which is lower much than the BAU case. The peak demand grows from 5640MWs in 1996 to 16213.07MWs in 2011 at 5.8%, 7.6% and 8.6% per annum over the 9th, 10th and 11th plan periods respectively, which is significantly lower than the BAU case. The base and intermediate load levels are also tabulated along with the peak and energy demand forecasts. The forecasts further indicate that consequent upon T&D loss improvements the LDC curve is somewhat flattened from its BAU case, which would have several implications for the pattern of capacity expansion and generation having associated economic, financial and environmental implications.

Results

The simulation results for this scenario are presented in Table-A6.1 through Table-A6.22 of Appendix-6.

The optimal development trajectory indicates a 3.11 times increase in total installed capacity from 6735MWs in 1997 to 20979MWs in 2011, which is about 9.2% lower than the BAU case. The optimal capacity expansion schedule indicates additions of 502MWs in the 9th plan, 1725MWs in the 10th plan and 7548MWs over the 11th plan. This shows that capacity additions over all the plan periods are lower than corresponding capacity additions over respective plan periods for the BAU case. This is because of the lower requirements at the busbar for this scenario arising from the substantially reduced T&D losses. The optimal composition of the capacity expansion comprises of 7000MWs of domestic coal thermal, 232MWs of domestic gas thermal, 2400MWs of LNG based capacity, 110MWs of hydro project at Jurala and 33MWs of renewable projects (of which 27MWs are mini hydel projects). Thus, compared to BAU case the optimal composition in this scenario indicates lower gas (domestic and imported) based capacity additions and less of renewable options. Besides less of combined cycle plants, it is observed that additions of peaking plants is considerably lower. It may be noted that imported coal option is not optimally chosen.

The optimal capacity addition schedule and installed capacity are tabulated in Table-A6.2 through Table-A6.5. It is observed that because of lower energy and load requirements at busbar, arising from assumed improvements in T&D losses, the optimal schedule and
composition of capacity additions are slightly different from the BAU case. However, the preferred sequence of the fuel types in capacity expansion almost remains the same as that of the BAU case. Because of lower energy and load demand, and flattening of the load duration curve, it is observed that the major hydro project and renewable options are not inducted first.

In most of the earlier scenarios these options were first inducted to meet the peak load requirement and close the much-desired demand-supply gap. Unlike the previous scenarios, it is as late as the terminal year of the 10th plan when the hydro project at Jurala is optimally inducted into the system. In this scenario, thus, domestic coal thermal plants at Talcher pithead are preferred first, followed by coal thermal plants at Singareni pithead when resource availability limits from Talcher are reached. However, constrained by further production build-ups from Singareni, LNG and domestic gas based combined cycle plants emerges as the next preferred supply option. It may be noted that, with significantly reduced peak demand, in this scenario very little renewable options are actually envisaged to be added over the planning horizon. Amongst the renewable options, mini hydel projects are relatively more preferred as against wind projects. Interestingly, sans an LNG based open cycle plant inducted into the system over the 10th plan for meeting the minimum guarantee condition, no gas (domestic or imported) based open cycle plant is chosen over the planning horizon. Finally, it may be noted that load centre coal (domestic or imported) plants, naphtha based plants, and coal thermal plants using washed coal are not selected along the optimal development path. The optimal capacity additions are depicted in Chart-6.6. The optimal fuel requirements and their maximum availability are presented in Table-A6.12 and Table-A6.13 respectively.

Share of fuel types in total installed capacity are presented in Table-A6.5 and illustrated in Chart-6.1. The trends are fairly similar to the BAU case, with the coal thermal having the maximum share followed by hydro projects. However, it may be noted that as compared to the BAU case shares of gas, LNG and wind options are in general lower in this scenario. Further, although total domestic coal thermal capacity additions are same, since the timing of additions is different it is observed that the shares in this scenario for domestic coal, naphtha and hydro are different from the BAU case.

Outputs produced by different plants at different load levels are presented in Table-A6.6 through Table-A6.8. Chart-6.3 illustrates that share of coal is maximum in the base mode of operation, followed by hydro. Over the last few years of the 11th plan share of LNG is more than hydro in the base mode. Naphtha and domestic gas accounts for a very small proportion of the total contribution to the base mode. It is observed that with more and more commissioning of the committed plants, share of domestic coal in base mode goes up over the initial years of the 9th plan, but keeps fluctuating thereafter to reach a high of about 82.1% in 2008 and
eventually declines steadily from 2009 onwards. It is during the terminal years of the planning horizon when the share of domestic coal to total load generation in base mode declines that the share LNG is observed to increase. Share of naphtha in contribution to the base mode is observed to increase towards early years of the 9th plan, but thereafter declines with minor fluctuations. Shares of domestic gas and hydro are found to fluctuate within the plan periods, but the general trend is observed to decline over the planning horizon. Compared to the BAU scenario, in this scenario share of domestic coal in load generation in base mode is higher and that of hydro and LNG are lower. It is observed that relative to the BAU case shares of naphtha and domestic gas in the base mode over the 10th plan period are slightly higher. From the illustrations in Chart-6.4 it is observed that hydro mainly accounts for the contribution to the intermediate mode. Compared to the BAU case contribution of coal thermal to the intermediate mode over the planning horizon is lower and that of hydro is much higher in this scenario. As Chart-6.5 illustrates, excepting for the first two years of the planning horizon when wind option solely contributes to the peak mode, it is observed that hydro takes the lions' share in the total load generation in the peak mode. From the latter half of the 9th plan domestic coal thermal makes some contribution to the total load generation in the peak mode. However, over the 11th plan period it is observed that the share of domestic coal in the total load generation in the peak mode increases quite rapidly. It may be noted that amongst hydrocarbons, domestic gas and LNG makes quite insignificant contribution to the peak mode over the planning horizon whereas share of naphtha although declining is quite significant in the total contribution to the peak mode, particularly over the 10th and 11th plan periods. Share of hydro in the total load generation in the peak mode gradually declines over the 11th plan after some fluctuations over the earlier plan periods. As compared to the BAU case, share of hydro is less over the first two plans and more over the 11th plan period in the peak mode. Both shares of domestic gas and LNG are lower in the peak mode for this scenario as against the BAU case. Most notable is the higher share of naphtha in total generation in the peak mode in this scenario, relative to the BAU case. Share of coal thermal in peak mode generation in this scenario is higher for some years and lower for others over the planning horizon as compared to the BAU case.

The optimal energy generations for the plan years are tabulated in Table-A6.9 and shows that gross energy in this scenario grows 2.89 times from 37421.59GWhs in 1997 to 106551.67GWhs in 2011. Compared to the BAU case, gross energy generation and energy generation at busbar is lower in this scenario for obvious reasons, with the gap between the two scenarios increasing over the years. It is observed that share of future plants in annual energy generation at busbar is lower than that of the BAU case. This shows that the existing and committed plants are utilized much more in this scenario than the BAU case. Share of fuel types in total energy generation are tabulated in Table-A6.10 and illustrated in Chart-6.2, indicates that coal continues to be the mainstay in generation over the planning horizon. After an initial
decline over the early years of the 9th plan, when committed hydrocarbon based plants get commissioned, the share of coal in total energy generation gradually increases over the 10th plan with slight fluctuations in some of the years. However, with the induction of LNG based plants over the 11th plan, the share of coal steadily declines over this period. But even at its maximum low, coal accounts for more than 66% of the total generation. Over the first two plan periods hydro makes significant contribution to the total energy generation, but with little fresh hydro projects getting inducted into the system it is observed that the share of hydro in total generation steadily declines over the planning horizon. Similarly with no fresh naphtha based capacity additions, the share of naphtha in total energy generation gradually declines over the planning horizon. Although relatively quite little, domestic gas and naphtha makes a fairly regular contribution to the total energy generation. Notable amongst the options is the rapidly increasing contribution of LNG based plants, particularly over the last few years of the 11th plan period. Relative to the BAU case it may be noted that the shares of domestic coal and naphtha in total energy generation in this scenario are generally higher over the planning horizon. Share of domestic gas between the latter half of the 9th plan and the first half of the 11th plan is higher, but thereafter lower, as compared to the BAU case. Share of LNG in this scenario is distinctly lower than the BAU case. Share of hydro over the 9th and 10th plan is observed to be lower and that over the 11th plan higher relative to the BAU case. However, since the total energy and load requirements at the busbar is much lower than the BAU case, the increased shares of coal and naphtha is unlikely to deteriorate the environmental ambience. Moreover, the preference for domestic resources as against the imported fuels in this scenario would have several economic implications.

Chart-6.7 illustrating the PLFs of the various fuel types tabulated in Table-A6.11 indicates high utilization of domestic coal based plants, notwithstanding slightly lower utilization of Singareni coal based plants relative to the BAU case in some of the years. However, over the 11th plan the PLFs of Talcher coal based plants indicate considerable decrease in capacity utilization. The naphtha based plants indicate very high levels of utilization of installed capacity over the initial years of the 9th plan, but decreases thereafter and almost stabilizes, only to increase slightly during the terminal years of the 11th plan period. Unlike earlier scenarios it is observed that capacity utilization of gas based installed capacity for the initial years is low but increases substantially over the 10th plan and remains fairly high with occasional fluctuations. Notable as in most of the previous scenarios, is the rapidly increasing capacity utilization of installed capacity for the LNG based options over the 11th plan period. PLFs of the hydro options are almost the same as that of the BAU case. It is observed that in this scenario capacity utilization of wind options and open cycle plants are very low as compared to the BAU case. This is because of the lower load demand and flattening of the LDC arising from the improvement in T&D losses. Slightly higher overall
PLFs is a direct consequence of the improved SLFs arising from improvement in T&D losses of the system. Reserve capacities for this scenario are presented in Table-A6.15 and illustrated in Chart-6.13. The table indicates that, compared to the BAU case, notwithstanding lower demand of energy as well as load and flattening of the LDC, this scenario indicates higher overall reserve capacity as well as reserves in ‘cold’ condition required to ensure minimum guarantee condition of the system. It may be noted that such higher reserve capacity, especially as standby units, has important financial implications. Apart from this, the fact that reserve capacity in ‘hot’ condition for this scenario are lower than the BAU case implies that in case of a sudden substantial forced outage the system may be thrown out of gear, notwithstanding the presence of enough reserve capacity ensuring minimum guarantee condition.

The present discounted value of the system cost for this development trajectory at Rs.378.5 billion is about 5% lower than the BAU case. Further, the levelised average cost at 1.039 Rs/kWh is about 1.8% lower than the BAU case, notwithstanding lower energy requirements arising from improvements in T&D losses. Also the levelised average cost for future plants at 1.20 Rs/kWh is observed to be lower than the BAU case. The levelised average capital as well as fuel costs for future plants are lower than the BAU case. Thus, with reference to the cost situations for this scenario, it appears that this development strategy is reasonably attractive, notwithstanding the adverse financial implications arising from the requirement of a larger reserve capacity. However, it still remains to be seen whether this development strategy is at all viable in the first place. For this the present discounted value of the stream of expenses incurred on measures for T&D loss reduction over the planning horizon are compared with the difference in present discounted system costs between the BAU case and this scenario. This is essentially a rough cost-benefit analysis to assess the viability of T&D reforms as a development strategy. The present discounted net benefit, which is estimated at Rs.19144.7 millions (tabulated in Table-A6.22), being non-negative, ensures the viability of this development strategy.

Table-A6.14 presents the share of each fuel type in the total fuel requirements, which are also illustrated in Chart-6.8. The shares of fuels in total fuel requirements are almost the same as that of the BAU case except for the 11th plan period, when the share of coal is envisaged to exceed the BAU case and those of domestic gas and LNG lower than the BAU case. Share of naphtha is almost the same in both the scenarios. However, as already mentioned, notwithstanding the higher shares of fossil fuel and lower share of hydrocarbons in the total fuel requirements, because of lower energy/load requirement and, hence, lower generation the environmental situation may not worsen, and in fact may improve. Further, a development plan consistent with national priorities, such as this, arising from less dependence on imported fuels and improved cost situations, may in fact be quite an attractive development strategy. What remains to be assessed is the environmental fallout of this development path so as to endorse the viability of this development strategy.
The shares of fuel types in total annual emissions of pollutants are tabulated in Table-A6.16 through Table-A6.19. These shares indicate that domestic coal may be solely held responsible for the emission of TSP over the planning horizon, which is quite in consonance with the earlier scenarios. Domestic coal also has the maximum share among the fuel types in total the annual emission of SO$_x$, with naphtha accounting for the significantly small remaining portion. These shares and their trends over the planning horizon are observed to be quite similar to the BAU case, except that in this scenario imported coal does not figure at all and domestic coal mainly substitutes for the imported coal in total annual emissions. However, it is observed that although over the 9th and 10th plans the shares of fuels in total annual NO$_x$ emission are almost the same as that of the BAU case, over the 11th plan the share of domestic coal in annual emission is higher and those of domestic gas as well as LNG are lower. Share of naphtha in total annual NO$_x$ emission is almost the same as that of the BAU case. Similarly for CO$_2$ emission it is observed that share of domestic coal over the 11th plan is slightly higher and those of domestic gas as well as LNG slightly lower than the BAU case, with share of naphtha almost the same in both the scenarios. Not much variation in shares for the fuel types is observed for the first two plans of the planning horizon. Table-A6.20 presents the shares of the fuel types in the cumulative emission of pollutants and is illustrated in Chart-6.9. These shares also endorse that domestic coal accounts for the maximum share in the cumulative emission of all the pollutants. Thus, relative to the BAU case, share of domestic coal is higher and that of LNG lower in the emission of NO$_x$ and CO$_2$, while the other shares for the pollutants remain almost the same.

The annual total emissions of pollutants over the planning horizon that is tabulated in Table-A6.21 are illustrated in Chart-6.10 through Chart-6.12. Relative to the BAU case it is observed that the annual emissions of all the pollutants over the 10th and 11th plan periods are substantially lower in this scenario. However, the increase in emission in this scenario is more gradual, unlike the BAU case where there is a steep increase between the terminal years of the 10th plan and early 11th plan period. Similar to the previous scenarios, it is observed that the rate of emissions decrease towards the terminal years of planning horizon. Thus, along this development trajectory, TSP emission grows 2.74 times, SO$_x$ emission also rises 2.74 times, NO$_x$ emission grows 2.87 times, CO$_2$ emission increases 2.99 times and Ash discharge grows 2.74 times. It is observed that cumulative emission of all the pollutants are 2.5-3.6% lower in this scenario relative to the BAU case, with the maximum reductions envisaged for the NO$_x$ and CO$_2$ emissions. Further, even the present discounted emissions of local pollutants are 2.2-2.6% lower in this scenario. However, not much variation is envisaged in the undiscounted levelised average emission of pollutants. Although the emission reductions are not very high, nevertheless lower emissions along the optimal development path for this scenario renders this strategy viable on environmental consideration as well.
Thus, reiterating, it may be deduced from the above analyses that improvement in T&D losses through appropriate and proactive reforms has significantly favourable economic, financial and environmental implications. Although, the cost reductions are much more than the reduction in emissions, the fact that in absolute terms the environmental situation improves and dependence on imported fuels as well as hydrocarbon reduces, have obvious benefits along the development of the power sector. The reduction of emission in this scenario is slightly dampened because of the higher share of domestic coal in power generation along the optimal development path, especially over the 11th plan period. Therefore, in view of the fact that there is ample scope for improving the quality of services in a system marked by poor quality of power supply and high T&D losses (both technical and non-technical), T&D reform may qualify as an attractive mitigation and power sector development strategy.
Chart-6.1
Share of Fuel Types in Total Installed Capacity

Chart-6.2
Share of Each Fuel Type in Total Energy Generation
Chart-6.3
Share of Fuel Type in Base Mode Generation

Chart-6.4
Share of Each fuel Types in Intermediate Mode Generation
CHARTS for T&D Reform Scenario

Chart-6.5
Share of Each Fuel Types in Peak Mode Generation

Chart-6.6
Capacity Additions over the Plan Periods (MWs)
Chart-6.9
Share of Fuel Types in Cumulative Emission of Pollutants
(TSP, SOx, NOx, CO2)

Chart-6.10
Annual CO2 Emissions
Chart-6.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-6.12
Total Annual Emission of ASH
(Million Tons)
Chart-6.13
Reserve Margins:'HOT' and 'COLD'

Years

Reserve Margins (MWs)
7. Demand Side Management Scenario (DSM)

As already mentioned in the context of the previous scenario, present trends in power planning indicate a shift towards an altogether new paradigm where the emphasis is more on energy services. Conservation on the demand side may be achieved through alternative policies of rationalizing tariffs, efficiency improvements of end-use appliances, and better energy management and auditing. Since rationalizing tariffs is a long term 'strategic' policy measure involving considerable motivation and will of the polity, tariff changes, besides what is considered in BAU scenario, are not considered in this study. ‘Tactical’ short term solution such as end-use efficiency improvements and conservation in energy use at the consumers’ end would not only yield effective capacity additions in the power sector but would considerably reduce environmental fallout of power sector development. This study, thus, assumes energy conservation and peak ‘shaving’ possibilities due to efficiency improvements in end-use appliances, introduction of more efficient technologies, demand management and energy auditing, as identified by the IRP Study (1996) of Andhra Pradesh. Fresh estimates of energy and peak forecasts are obtained after incorporating adjustments due to demand side management (DSM), and LDCs constructed for each year of the study period.

Thus, this again, like the previous scenario, is a variation of the BAU scenario with only the demand adjusted to account for the efforts towards energy conservation through Demand Side Management measures. The various cost-effective programs identified by the IRP Study, their descriptions, implementation procedures and assumptions on the demand adjustments (i.e. extent of energy and peak demand reduction, through the various end-uses in the different sectors) are detailed in chapter-5 along with the final energy and peak forecasts. These forecasts along with the LDC parameters presented in chapter-6 are used to obtain fresh LDCs for the planning years. The load levels and the energy demands obtained are tabulated in Table-A7.1 of Appendix-7. These forecasts indicate that energy demand grows at the rate of 4.4%, 6.1% and 9.2% per annum over the 9th, 10th and 11th plans respectively. Energy demand therefore increases 2.59 times from 37599GWhs in 1996 to 97465.39GWhs in 2011. Peak demand for this scenario increases from 5640MWs in 1996 to 16910.14MWs in 2011 at the rate of 5.3%, 8% and 9.5% per annum over the 9th, 10th and 11th plan periods respectively. However, unlike the demand situation envisaged for the previous scenario, the load shape for this scenario relative to the BAU case does not change much under the present assumptions, notwithstanding significant savings in energy and load. Further, as also indicated by the growth rates, maximum savings are envisaged over the first two plan periods, to be followed by a rapid growth in energy and load demands over the 11th plan period. Thus the LDCs may continue to be skewed over the 11th plan period even with lower energy and load requirements.
Results

The simulation results for this scenario are presented in Table-A7.1 through Table-A7.21 of Appendix-7.

The optimal trajectory indicates a 3.2 times increase in total installed capacity from 6735MWs in 1997 to 21565MWs in 2011, which is about 6.7% lower than the BAU case but about 2.7% higher than the TDREF case. The optimal capacity expansion schedule indicates additions of 511MWs, 1751MWs and 8099MWs over the 9th, 10th and 11th plans respectively. This shows that although capacity additions over each plan is lower than the BAU case, but compared to the TDREF scenario capacity additions over each period in this scenario is higher.

The optimal composition of the capacity expansion comprises of 7000MWs of domestic coal thermal, 732MWs of domestic gas thermal, 2240MWs of LNG based capacity, 210MWs of imported coal based thermal capacity, 110MWs of hydro project at Jurala and 69MWs of renewable projects. Thus, compared to the BAU case, this scenario envisages more of renewable projects (i.e. wind projects) and domestic gas based capacity, which is in direct contrast to the TDREF scenario where optimal expansion schedule indicates less of these two supply options. Further, it may be noted that, unlike the TDREF scenario, the optimal development trajectory indicates substantial additions of open cycle plants. These along with the renewable projects are used to meet the peak load requirements and also ensure minimum guarantee condition of the system. It is also observed that, compared to the BAU case, more of domestic gas and renewable capacities whereas less of imported fuel based capacities are added to the system, which has important economic and environmental implications.

The optimal capacity addition schedule and the installed capacity are tabulated in Table-A7.2 through Table-A7.5. It is observed that consequent upon the energy and load savings, and subsequent alteration of the LDCs over the planning horizon, the timing of capacity additions of the various supply options, along with the size of additions are different from both the BAU case and TDREF scenario. Although the size and timing of capacity additions is different, it may be noted that the preferred sequence of the fuel types in capacity additions remains the same as that of the BAU case. Because of the reduced load due to DSM and substantial committed capacity in the system, it is observed that the induction of major hydro project is deferred to the 10th plan period. However, in the face of existing demand-supply gap, a coal thermal plant at Talcher pithead is inducted along with renewable projects at the very outset. The sequence observed is that Talcher pithead plant is first preferred as base load plant, followed by pithead plants using Singareni coal when resource constraints are met. Although domestic gas based combined cycle plants is added to the system before Singareni pithead plant, it may be noted that the gas plant was added to the system mainly for meeting peak load requirements and not as a base load plant. Constrained by the production build-ups from Singareni, next in the preference order is the domestic gas based combined cycle plant,
initially used for peaking purpose but when energy demand increases substantially these plants are used as base load units. Further constrained by the limited availability of domestic gas, LNG based combined cycle plants are next preferred mainly as base load plants, although they also contribute towards meeting the peak load of the system. Finally, constrained by the maximum build-limits of the LNG based combined cycle plants at regassification points, imported coal based thermal plants at load centre are preferred for operating in the base mode of the system in the terminal year of the planning horizon. Alongside additions of base load plants renewable projects are regularly added to cater to the peak load requirements and guarantee condition of the system. *From the terminal years of the 10th plan and more during the terminal years of the 11th plan, when the peak demand facing the power system is fairly high, substantial domestic gas and LNG based open cycle plants are also inducted.* These also serve the twin purpose of contributing towards meeting the minimum guarantee condition of the system. However, it may be noted that load centre plants using domestic coal, thermal plants using unwashed coal and naphtha based plants are not preferred along the optimal development path. *Relative to the BAU case, in this scenario it is observed that over the first two plans less of domestic coal thermal plants and wind projects are added to the system. But over the 11th plan more of these relative to the BAU case are added to the system.* The optimal capacity additions are illustrated in Chart-7.6. The optimal fuel requirements and their maximum availability are presented in Table-A7.12 and Table-A7.13 respectively.

Share of fuel types in total installed capacity are presented in Table-A7.5 and illustrated in Chart-7.1. These indicate that, similar to the BAU case, coal has the maximum share in total installed capacity and is supplemented by hydro projects. Relative to the BAU case it is observed that share of coal thermal is higher over the planning horizon. Share of naphtha is slightly higher over the 10th and 11th plans, and share of domestic gas in total installed capacity almost the same with only minor fluctuations, relative to the BAU case. Shares of LNG and imported coal are lower in this scenario as against the BAU case. It is further observed that share of hydro over the 10th plan is slightly lower and over the 11th plan slightly higher in this scenario as compared to the BAU scenario. *Thus, in this scenario the proportion of domestic fuel based capacity is higher and that of imported fuel based capacity lower than the BAU case. This has obvious important economic implications with reference to the consistency of development strategies with national priorities.*

Outputs produced by different plants at different load levels are tabulated in Table-A7.6 through Table-A7.8. Chart-7.3 illustrating the shares of fuel types in the base mode generation indicates domestic coal having the maximum share in the base mode. It is observed that the share of coal goes up gradually over the planning horizon, with occasional fluctuations over the 10th plan period, and comes down from the penultimate year of the planning horizon
being displaced by LNG based generation. Coal thermal generation in the base mode is supplemented by hydro generation but declines over the planning horizon. Naphtha and domestic gas based options contribute little but significantly to the base mode. The share of naphtha in base mode generation shows an initial increase over the 9th and early years of the 10th plan as more and more committed plants get online, but thereafter decreases at a steady rate since no fresh capacities are added to the system. The share of domestic gas in base mode generation, however, keeps fluctuating over the 10th and 11th plan periods mainly acting to bridge the demand-supply gap. Imported coal makes very little contribution and that too only in the last year of the planning horizon. Compared to the BAU case, it is observed that the share of coal in the base mode is slightly lower over the 10th plan but is higher over the 11th plan period. Further, relative to BAU case, share of LNG and imported coal is lower and share of naphtha is slightly higher in the base mode for this scenario. From the illustration in Chart-7.4 it is clearly evident that hydro mainly caters to the load generation in intermediate mode. Share of hydro in the total load generation in the intermediate mode in this scenario is slightly higher than the BAU case. Coal supplements hydro in intermediate mode in the 10th and 11th plans, with slightly higher contribution over the 11th plan. However, compared to the BAU case, coal makes lesser contribution to the intermediate mode over the planning horizon, notwithstanding higher shares in some of the years especially over the 11th plan period. Wind projects make some contribution, although very little, to the load generation in the intermediate mode. Chart-7.5 indicates that except for the first two years of the planning horizon when wind option solely contributes to the peak mode, hydro accounts for the maximum share in the total load generation the peak mode. Although domestic coal makes some contribution to the peak mode over the 9th plan period, their share goes up gradually over the two plan periods of the planning horizon. Naphtha makes quite significant contribution to the peak mode over the 10th and 11th plans, although the share decreases over the 11th plan period. Domestic gas makes little contribution over the 9th and 10th plans, but the share is much higher over the 11th plan period, supported by LNG over the last two years of the planning horizon. It may be noted that, compared to the BAU case, in this scenario share of naphtha and domestic coal is higher, share of LNG lower and imported coal not generating at all in the peak mode. Share of hydro in the peak mode for this scenario is slightly lower over the first two plan periods and slightly higher over the 11th plan than the BAU scenario. Thus, relative to the BAU case, in this scenario not only is the share of imported fuel based options lower in the total installed capacity, but shares of imported fuel based options in the various modes of operation are also lower.

The optimal energy generations for the plan years, as tabulated in Table-A7.9, indicate 2.8 times increase in gross energy generation from 37421.59GWhs in 1997 to 104606.72GWhs in 2011. Because with the lower requirements in this scenario, consequent upon the adoption of DSM measures, the annual gross energy generations and energy generations at busbar over the
planning horizon are lower than the BAU case. Similar to the TDREF case, in this scenario the share of future plants in total energy generation at busbar is lower than the BAU case, notwithstanding the increase in share over the planning horizon. This shows that in this scenario, with reduced requirements at busbar, the existing and committed capacities make substantial contribution to ensure demand-supply balance. However, it is observed that over the 11th plan period the share of future plants rises quite sharply and towards the terminal years of the planning horizon they make the main contribution being supplemented by the existing capacities. It may be further noted that the share of future plants in total energy generation at busbar in this scenario marginally exceeds those observed in the TDREF scenario.

Share of fuel types in total energy generation, as tabulated in Table-A7.10 and illustrated in Chart-7.2, shows that domestic coal has the maximum share in the total energy generation over the planning horizon. This share gradually increases over the planning horizon and declines over the last two years of the terminal plan period when contribution of LNG in total generation increases. Energy generation by domestic coal is supplemented by hydro, but with fewer capacity additions and limited energy potential the share steadily decreases over the planning horizon. Domestic gas and naphtha, although making relatively little contribution, provides the necessary support to ensure the desired demand-supply balance. However, it is observed that, with no fresh capacity additions, the share of naphtha in total energy generation decreases over the plan periods. Share of domestic gas, although declines through the early years of the 10th plan periods, keeps fluctuating over the rest of the planning horizon. Notable is the increase in share of LNG in the last two years of the planning horizon, supported by imported coal based generation in the terminal year of the planning horizon. However, compared to the BAU case, it is observed that in this scenario share of coal in total generation is lower over the 10th plan and higher over the 11th plan, but the share of hydro is higher over all the plan periods. Share of naphtha and domestic gas in total generation, over the planning horizon, are almost the same in this scenario and the BAU case. Compared to the TDREF scenario it is observed that the share of domestic coal and naphtha in total energy generation over the first two plan periods is slightly lower but over the 11th plan is slightly higher in this scenario. Further, in this scenario the share of hydro is higher and LNG lower in total energy generation over the planning horizon relative to the TDREF case. Chart-7.7 illustrating the PLFs of the various fuel types tabulated in Table-A7.11 indicates high utilization of domestic coal, LNG and imported coal based plants. However, relative to BAU case, Singareni coal based plants indicate marginally lower utilization in this scenario. Talcher coal based plants indicate a gradual decrease over the planning periods, especially over the 11th plan. PLFs of the naphtha and hydro options are almost the same as the BAU case. However, the PLFs of wind projects are higher in this scenario as against the BAU case over the 11th plan period. PLFs of the
domestic gas based options are marginally lower in this scenario in comparison to the BAU scenario. Finally the overall PLFs are lower in this scenario as against the BAU case. These indicate the influence of the load shapes and the LDCs. The reserve capacities for this scenario are tabulated in Table-A7.15 and illustrated in Chart-7.13. It is observed that because of lower requirements arising from the DSM measures and with substantial capacities being already committed, over the initial years of the planning horizon the reserve capacity in this scenario is higher than the BAU case, and this persists through the 10th plan. However, thereafter as the load requirements increase, since savings due to DSM tapers off, and the system grows, the reserve capacity to ensure system reliability and minimum guarantee condition falls below the BAU level. Almost the same pattern is observed for the reserve capacity in 'cold' condition as well. Besides, since the reserve margin as it is defined here really represents reserve margin of utilizable capacity, a decrease in reserve may be also attributable to the induction of more and more hydrocarbon based plants as the system grows. However, it is observed that, relative to the BAU case, in this scenario the reserve capacity in 'hot' condition over the first two plan periods remain almost the same, but over the 11th plan period this is marginally lower. Thus, the pattern and extent of the system reserve capacity in this scenario show that the system slightly less resilient to sudden outages as compared to the BAU case. But it may be noted that the overall reserve capacity and reserve capacity in 'cold' condition in this scenario is marginally lower and reserve capacity in 'hot' condition marginally higher than the TDREF scenario. However, the unmet energy in this scenario is lower than the BAU case since energy savings through DSM measures are assumed from 1998. Consequently the present value cost of unserved energy at Rs.50.08 billion is also significantly lower in this scenario than the BAU case. This benefit reaped is an additional advantage of this scenario over all the other scenarios discussed thus far.

The present discounted value of system cost for this scenario at Rs.362.5 billion is about 8.7% lower and the levelised average cost at 1.034 Rs/KWh is about 2.3% lower than the BAU scenario. The fact that levelised average cost is lower than the BAU case, notwithstanding lower generation because of lower requirements in this scenario, indicates that the system cost savings is much more than the energy savings arising from the inclusion of DSM measures in present value terms. Further it may be noted that the levelised average cost of generation by future plants at 1.20 Rs/KWh is lower than the BAU case and same as that of the TDREF scenario. However, with reference to the TDREF scenario, in this scenario the levelised average capital cost is higher and the levelised average fuel cost lower for the future plants. Thus, these observations have important implications for the cost effectiveness of this development strategy as against the other scenarios, inclusive of the reference scenario. However, the picture is rendered complete on cost considerations when the stream of system cost savings as influenced by the DSM measures is compared with the cost stream of implementing the DSM measures. The present discounted value of the entire economic cost
(utility costs plus consumer costs) stream of implementing the proposed DSM measures, as given in IRP (1996), are estimated and compared with the present discounted value of system cost savings along the development trajectory. Therefore, comparing a present value benefit of Rs.44.96 billion, arising from system cost savings, with present value cost of Rs.15.77 billion, due to expenses on DSM, yields a non-negative present value net benefit of Rs.29.18 billion, which endorses the cost effectiveness of DSM as a development strategy.

The shares of fuel types in total fuel requirements, as tabulated in Table-A7.14 and illustrated in Chart-7.8, shows that the trend in this scenario is comparable with that of the BAU case, although the shares are somewhat in variance. Thus, it is observed that domestic coal accounts for the maximum share in the total fuel requirements reaching a maximum of about 93.7% in the 11th plan period with occasional fluctuations. However, over the last two years of the planning horizon this share gradually declines to reach a low of 79.1% by the terminal year, as the share of LNG goes up marginally supplemented by imported coal. Compared to the BAU case, it is observed that share of coal in total fuel requirement over the first two plans are lower and over the 11th plan period slightly higher in this scenario. Share of naphtha in the total fuel requirement is observed to be marginally higher in this scenario relative to the BAU case. Whereas, share of domestic gas, in total fuel requirement, is observed to be marginally higher from the latter half of the 10th plan in this scenario as against the BAU case. However, shares of imported fuels are observed to be lower in this scenario relative to the BAU case. Compared to TDREF scenario shares of domestic gas and naphtha in total fuel requirement over the planning horizon are marginally higher, and share of domestic coal is slightly higher over the 11th plan period. But it is clearly observable that the share of LNG in total fuel requirement is much lower in this scenario.

The shares of fuel types in total annual emission of pollutants are presented in Table-A7.16 through Table-A7.19. These shares indicate that domestic coal is solely responsible for the pollution arising from fugitive TSP emissions, except in the last year of the planning horizon when imported coal contributes only about 0.4% of the total emission. Domestic coal also accounts for the maximum share in the total emission of SO₂, supplemented by naphtha, and almost follows the same pattern as that of the BAU case. In the last year of the planning horizon imported coal makes a very small contribution, much less than the BAU case. With reference to NOx emission it is observed that over the first two plans of the planning horizon share of domestic coal is marginally lower and that of domestic gas marginally higher, but over the 11th plan share of domestic coal is higher and domestic gas lower relative to the BAU case. Shares of LNG and imported coal in NOx emission are lower, and that of naphtha almost the same, in this scenario as against the BAU case. In case of CO₂ emission it is observed that share of domestic coal in total emission is slightly lower over the first two plans but higher over the 11th plan in comparison to the BAU case. Share of domestic gas in CO₂ emission is slightly lower over the 10th and 11th plans, while that of naphtha slightly higher over the planning
horizon relative to the BAU case. Finally, shares of LNG and imported coal in CO₂ emission are lower than the BAU case. It appears that share of gas and naphtha are slightly higher and that of LNG lower in the emission of pollutants over the planning horizon in this scenario as against the TDREF case. Share of fuel types in the cumulative emission of pollutants are presented in Table-A7.20 and illustrated in Chart-7.9. These indicate that share of coal accounts for the maximum share in all the pollutants and are higher than the BAU case. It is also observed that shares of imported fuels are lower in this scenario as against the BAU case. With reference to cumulative CO₂ emission it is observed that share of domestic gas is marginally lower and that of naphtha marginally higher than the BAU case. Finally, in comparison to the TDREF scenario the share of LNG is lower in all the pollutants in this scenario.

The annual total emissions of the pollutants over the planning horizon are tabulated in the Table-A7.21 and illustrated in Chart-7.10 through Chart-7.12. It is observed that compared to the BAU case the annual emissions of all the pollutants are lower over the planning horizon in this scenario. However, in this scenario it may be noted that the rates of increase of emissions over the latter half of the 10th plan and through the terminal years of the 11th plan are quite steep, and stabilizes much later, than the BAU case. Along the optimal development trajectory TSP emission rises 2.75 times, SO₂ emission grows 2.80 times, NOₓ emission rises 2.895 times, CO₂ emission increases 2.991 times and Ash discharge increases 2.75 times. It may be noted that rises in all the pollutants are lower than the BAU case. However, except for CO₂ emission, in this scenario the emissions of all local pollutants eventually increase much more than the TDREF scenario. This may be explained by the combustion of imported coal in the last year of the planning horizon, along with increased combustion of domestic coal, in this scenario relative to the BAU case. It should be noted that for all years of the planning horizon, except for the terminal year, emission of pollutants in this scenario is less than that of the TDREF case. Thus, the terminal year seems to be an outlier causing such an aberration environmental condition along this development trajectory as against the TDREF case. Therefore, substantially lower emissions of pollutants over the planning horizon for this scenario emphasizes the attractiveness of this strategy on environmental considerations as well. In terms of cumulative emissions, it is observed that benefits arising from DSM measures, in this scenario, yield 6.4% less of TSP emission, 6.6% less of SO₂, 7.2% less of NOₓ, 7.8% less of CO₂ and 6.3% lower Ash discharge than the BAU case. This indicates that maximum reductions of emissions over the BAU case are envisaged for NOₓ and CO₂. It should be noted that higher emissions reductions are possible with DSM measures than the TDREF case. These therefore consolidate the viability and attractiveness of DSM measures as an effective development strategy on environmental consideration as well.

Thus, integration of DSM measures within the planning framework yields considerable economic, financial and environmental benefits along the development trajectory. In view of the
above analysis, it may be asserted that a development strategy such as this is also consistent with national priorities of self-reliance, improved services, equity and social welfare. In comparison to all the scenarios discussed thus far, the development trajectory obtained for this strategy yields a win-win situation with both reduced cost and emission situations together with reduced dependence on imported fuels. This strategy clearly occupies an important place in the development of a power sector, inherently plagued by resource constraints, performance bottlenecks, poor quality of supply and services besides the rapid deterioration of the environment. The above analysis also endorses the widely held belief that DSM measures play a vital role in the mitigation of environmental impacts of power sector. Therefore, integrating DSM measures in power planning seems to be the short to medium term solution for the electricity sector caught between environmental challenges and harsh economic, social and political realities. However, notwithstanding, the obvious benefits of adopting DSM measures, actual implementation and penetration have been rather poor because of myriad impediments. This has serious implications for a rapidly growing power sector, its present financial status, and the reluctance to reform power tariffs. Thus, although there lies tremendous economic, financial and environmental potential with the DSM measures, their actual realization involves serious efforts from the Government and the Utility.
Chart-7.1
Share of Fuel Types in Total Installed Capacity

Chart-7.2
Share of Each Fuel Type in Total Energy Generation
Chart-7.3
Share of Fuel Type in Base Mode Generation

Chart-7.4
Share of Each fuel Types in Intermediate Mode Generation
Chart-7.5
Share of Each Fuel Types in Peak Mode Generation

Chart-7.6
Capacity Additions over the Plan Periods (MWs)
Chart-7.7
Plant Load Factors

Chart-7.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-7.9
Share of Fuel Types in Cumulative Emission of Pollutants (TSP, SOx, NOx, CO2)

Chart-7.10
Annual CO2 Emissions
CHARTS for Demand Side Management Scenario

Chart-7.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-7.12
Total Annual Emission of ASH
(Million Tons)
Chart-7.13
Reserve Margins-'HOT' and 'COLD'

Years
C. Command-and-Control Policies

As already discussed in chapter 1, the ubiquitous presence of uncertainty in economic decisions and also in the determination of the cause-effect relationship creates tremendous problems to valuation of environmental valuation of damages and assets. Consequently, policy formulation to address sustainability of the development process becomes a difficult because of this presence of uncertainty and asymmetric information. Traditionally C&C policies were mostly relied upon for environmental protection, but lost its popularity mainly because of the difficulties in their implementation and enforcement. However, C&C policies, since they guarantee environmental action through legal sanctions, have been hailed in the literature to be an effective policy to address uncertainties. There is considerable uncertainty about the impacts of Global Warming. However, given the monstrosity of the potential consequences caution is warranted. C&C policies are proposed in the international fora to address the issue of stabilizing emissions of global pollutants, where the cause-effect relation is not very well understood for these pollutants but the risks of neglect and costs of damage are extremely high. In view of the raging global environmental policy debate it would be appropriate to look at the implications of imposing quantitative restriction on the emissions of GHGs.

At the international meetings of the FCCC it has been time and again proposed to stabilize CO₂ emissions to the level that prevailed in year 1990. In response to this proposal for ‘Grandfathered Emission’ standard India has been defending its case along with other developing countries. In fact, as already mentioned earlier, in a recently convened meeting India along with other developing countries have earned themselves the right to pollute to achieve their development goals. Thus, although at present India does not assign much priority towards regulating emissions of global pollutants, nevertheless considering the high growth rate of CO₂ emissions it would be interesting to observe the implications of imposing such quantitative restrictions on CO₂ emissions from the power sector. In view of this the following scenario and its variation is constructed to assess the nature of development of the power sector in the presence of such a restriction from year 2011 onwards.

8. Quantitative Restrictions on CO₂ Emission at 1990 level from 2011 (CO21)

This scenario captures the imposition of a quantitative restriction on the maximum amount of permissible CO₂ emission from 2011 onwards. Thus it is assumed that from 2011 onwards CO₂ emission should not exceed the 1990 level. This is in accordance with the GHG abatement requirements, or ‘Grandfathered Emission’ standard, proposed at the international fora.
Experimentation with this policy driven scenario requires the emission restriction equation for GHGs defined in chapter-3 to be slightly modified to represent this scenario. Thus, the redefined equation involves emissions to be fixed at the 1990 level only from the terminal year of the planning horizon (i.e. 2011), with no restrictions on emissions in the preceding years of the planning period. Thus taking cue from the equation defined in chapter-3, this restriction may be defined in notational form as:

$$CO_{2f=2011}^{1990} \leq CO_{2}$$, where $CO_{2} = CO_{2f=1990}$

i.e. the upper bound implies CO₂ emission in 1990 from the power sector in Andhra Pradesh.

To arrive at the 1990 inventory for CO₂ emission from the power sector, total generation from the state and central sector coal and gas thermal plants is taken, along with the heat rates of the plants and heat value of coal that prevailed in 1990

$^{197}$, and the emission conversion factors. Since the central sectors contribution is given as aggregate data, it is assumed that NTPC (i.e. RTS-A) share in total CGS contribution to A.P. is 72% (approximately) based on the 1993/94 through 1996/97 data available and includes the regular contribution from unallocated share to A.P. Thus, generation by NTPC to A.P. is taken as 1962GWhs with a coal consumption of 1.37MT and carbon content of the coal used is 36.03%. Total generation in 1990 from the state units (coal) is taken as 8102GWhs and from gas thermal stations as 109GWhs. Therefore the total emission of CO₂ is estimated as 10.56mill.tons in 1990 from A.P. power sector.

However, since coal is the mainstay of generation and is expected to remain so over the next 10-15 years, as evident from the BAU analysis, therefore the emission restriction constraint as defined here may pose infeasibility problems to the optimization exercise. Thus, the model is adjusted through the introduction of a binary variable $w_{f}^{x}$, where $x \in \psi$, for $\psi$ as defined in chapter-3, taking values either zero or one, in the capacity/generation constraints and the cost equation (plants if not operated will not incur variable costs, but will still incur fixed costs). Thus, $w_{f}^{x} = 0$, if power plant $x$ is not operated in year $t$, and $w_{f}^{x} = 1$, if power plant $x$ is operated in year $t$.

Further the demand-supply balance constraints are adjusted such that the load generated at various demand levels is less than or equal to the corresponding demand level. This implies that there may be unserved energy and load in the system over the planning horizon. Thus, the assumption that supply should always meet the requirement at busbar is relaxed for this scenario. A very high penalty of 7 Rs/KWh is charged for energy not served in

$^{197}$ These figures are taken from the (1) Power Development in Andhra Pradesh: Statistics, 1995/96, APSEB and (2) Performance Review of Thermal Power Stations, 1993/94, APSEB.
the system along with an escalation rate on the penalty to account for the increasing social cost of energy not served. Consequent upon the modifications the model structure takes a non-linear mixed integer programming form. However, due to the non-availability of the specific solver compatible with GAMS2.25 needed to solve the non-linear mixed integer form, a relaxed mixed integer programming approach was taken to obtain the optimal development path for this scenario.

Results

The simulation results for this scenario are tabulated in Table-A8.1 through Table-A8.20 of Appendix-8.

The optimal development path indicates a 3.43 times increase in installed capacity from 6735MWs in 1997 to 23102MWs in 2011, which is almost the same as that of the BAU scenario. The optimal capacity expansion involves additions of 533MWs, 3059MWs and 8306MWs over the 9th, 10th and 11th plans respectively. This shows that capacity additions over the first two plan periods are lower and over the last plan higher than the BAU case. The optimal composition of the capacity addition schedule comprises of 7733MWs of coal thermal (including 727MWs of washed coal based plan at Singareni pithead), 1030MWs of domestic gas based capacity (including 234MWs of open-cycle plants at load centre), 110MWs of major hydro project at Jurala and 69MWs of renewable projects. These indicate that compared to the BAU case more of coal thermal plants, domestic gas based capacity and renewable projects are added, and less of LNG based capacity is added over the planning horizon. It may be also noted that, relative to the BAU case, in this scenario more open-cycle plants are added to the system but imported coal based options are not optimally chosen.

The optimal capacity addition schedule and the total installed capacity are presented in Table-A8.1 through Table-A8.4. It is observed that although the schedule of capacity additions is quite different from the BAU case, but the preferred sequence of fuel types in capacity additions are quite similar. Pithead plants using Talcher coal are first preferred and are followed by pithead plants using Singareni coal. But constrained by the production build-ups, domestic gas based combined cycle plants are the next on the preference list. But constrained by the gas availability and associated uncertainties, the capacity expansion path indicates preference for LNG based options. Finally in the terminal year of the planning horizon some washed coal based thermal plants at Singareni pithead are added to the system. Renewable projects, especially mini-hydel projects, are envisaged to be regularly added to the system and exploited to their maximum potential. The total fuel requirements are presented in Table-A8.11 through Table-A8.12. Unlike the BAU case, hydro project at Jurala are optimally inducted into the system over the 10th plan to meet the peak and intermediate loads mainly. It is observed that
the coal thermal plants are mainly added over the 10th plan and substantial gas (domestic and LNG) based capacity are added over the 11th plan periods supplementing more coal thermal plants. It may be however remembered that because of the relaxed mixed integer form of the simulated problem, the timing of capacity additions are to a great extent influenced by the continuity of the variables that are otherwise treated as integer variables. Thus, to dilute the distortions arising from this relaxation of the problem, an aggregate picture of the optimal solution would be more appropriate. Moreover, because of this relaxation of the problem, comparisons with the optimal trajectories for the other scenarios are not strictly applicable. The capacity addition schedule is illustrated in Chart-8.6.

The share of fuel types in total installed capacity as tabulated in Table-A8.4 and illustrated in Chart-8.1 indicates almost similar pattern of development over the planning horizon as that of the BAU scenario. It may be noted that compared to the BAU scenario share of coal is higher and that of LNG lower in this scenario, whereas shares of naphtha and wind are almost the same in the two scenarios. It is further observed that shares of hydro over the 9th and 10th plans are higher than the BAU case, and almost the same over the 11th plan period. It is also observed that relative to the BAU case the share of domestic gas in total installed capacity is higher over the latter half of the 11th plan period. It is therefore observed when the emission restriction for CO\textsubscript{2} is stringent; the shares of the less carbon intensive fuel based technologies are higher.

Outputs produced by the different plants at the different load levels are tabulated in Table-A8.5 through Table-A8.7 and are also illustrated in Chart-8.3 through Chart-8.5. Relative to the BAU case, the share of coal in the base mode is higher in this scenario and the share of hydro slightly lower. Moreover, except for the last year of the planning horizon, share of LNG in the base mode is lower as compared to the BAU case. Compared to the BAU case it is observed that the share of wind and hydro in the intermediate mode is higher and the share of coal in this mode lower. Moreover, relative to the BAU case, it is observed that share of fossil fuel and hydrocarbons in the peak mode generation are slightly higher and the share of hydro and wind lower for the first two plans. However, for the final plan period it is observed that the share of domestic gas in this mode is slightly higher. Thus, over the planning horizon prior to the terminal year with reference to capacity additions and the pattern of generation in the various modes of operation, it is observed that share of coal and domestic gas are in general higher than the BAU case and that of hydro and imported fuel lower. In the terminal year, because of stringent restrictions on CO\textsubscript{2} emission, share of carbon intensive fuel is replaced by the less carbon intensive hydrocarbons, hydro and renewable options. Therefore, if the entire planning horizon is considered and not just the terminal year, when the restriction is applicable, it is believed that the environmental and economic consequences would be quite onerous.
The optimal energy generation, tabulated in Table-A8.8 indicates a 2.81 times increase between 1997 and 2010, and then drops drastically by 67.5% over the last two years of the planning horizon. Thus, gross generation increases from 37421.59 GWhs to 105276.451 GWhs between 1997 and 2010, and thereafter declines to 34236.22 GWhs in 2011. This dramatic decline in generation is a consequence of the stringency of CO₂ emission restriction in the last year of the planning horizon. This indicates that in order to conform to the emission restriction energy demands would have to be left unserved and pay a heavy penalty for doing so. Thus, it is observed that starting of with relatively lower generation in the 9th plan, the generation increases over the 10th plan and through the first half of the 11th plan, as compared to the BAU case. However, for the latter half of the 11th plan, especially for the terminal year, it may be noted that gross energy generation is much lower than the BAU case. With reference to the future plants in total energy generation it is observed that after an initial decline over the 9th plan, the share increases gradually over the 10th and 11th plan periods.

Share of fuel types in total energy generation as presented in Table-A8.9 and illustrated in Chart-8.2 shows that coal is the main contributor and remain so over the entire planning horizon except for the last year of the planning horizon. It is observed that in the last year of the planning horizon coal and naphtha does not contribute at all and LNG based options make the maximum contribution, supplemented by domestic gas, hydro and wind projects. Over rest of the years prior to the restriction it is observed that the share of coal in total generation is higher than the BAU case. For the first two plan periods, share of hydro in total generation is lower and over the 11th plan this share for LNG and domestic gas lower, than the BAU case, except for the last year of the planning horizon. Thus, it is interesting to observe from the shares of fuels in total generation that, excepting for the last year of the planning horizon, for all the other earlier years share of fossil fuels in this case is higher than the BAU case. Although shares of fuel types in total generation are different from the BAU case, but it is observed that the changing pattern of the shares are somewhat similar to the reference scenario.

Chart-8.7 illustrating the PLFs of the various fuel types tabulated in Table-A8.10 indicates the high utilization of domestic coal and LNG based options. But similar to the other scenarios it is observed that the utilization of domestic coal gradually declines over the plan years and then sharply in the terminal years of the final plan. It is also observed that utilization of Talcher coal based plants is higher than the BAU case over the 10th and 11th plan periods. It is also observed that utilization of hydro options over the 10th plan is lower than the BAU case. The last year of the planning horizon as expected indicates considerable under-utilization of capacity in the system driven by the severe restriction on CO₂ emission. The reserve capacities as tabulated in Table-A8.14 indicates lower requirement of overall reserve capacity and also that in ‘cold’ condition relative to the BAU case. However, reserve capacity in ‘hot’ condition
is slightly higher than the BAU case. Although this indicates that the system is more resilient to sudden outages, but the under-utilization of capacity indicates the redundancy of this advantage in the restriction years. The present value cost of unserved energy in this scenario is much higher than the BAU case, because of the considerably large unmet energy in the year of CO\textsubscript{2} emission restriction. The unmet energy in the terminal year of the planning horizon is observed to be about 72996.07GWhs.

Table-A8.13 indicates that coal in the total fuel requirement has the maximum share among all the fossil and hydrocarbon fuels. Compared to the BAU case it is evident from the table that in this scenario share of coal is higher and that of gas (domestic and LNG) are marginally lower over the planning horizon. This table further shows that in the terminal year of the planning horizon when the emission restriction holds, it is only domestic gas and LNG that accounts for the total fuel requirements for generation and that the share of LNG far exceeds that of domestic gas. These are also illustrated in the Chart-8.8.

The present discounted value of system cost for this scenario at Rs.775.3 billion is about 95\% higher, and the levelised average cost at 2.14Rs/KWh is more than double the BAU case. It may be noted that the bulk of the higher present discounted value of the system cost may be attributable to the higher present discounted value of the cost of unserved energy. The present value cost of unserved energy obtained for this scenario is approximately Rs.441.48 billion, which is about 2.57 times that of the BAU case. The levelised average cost of future plant at 1.31Rs/KWh is about 5\% higher than the BAU case.

The shares of fuel types in the total annual emission of pollutants are presented in Table-A8.15 through Table-A8.18. These shares unfailingly show that coal is mainly responsible for the emission of local and global pollutants over the planning horizon. It is observed that domestic coal is mainly responsible for TSP emission except for the last year when LNG accounts for 82\% of the TSP emission. Coal is also mainly responsible for the SO\textsubscript{x} emission and naphtha making a very small contribution. However, for the last year of the planning horizon it is once again LNG that is mainly responsible for emission. Share of fuel types in NO\textsubscript{x} emission also follows similar pattern except that in the pre-restriction years other hydrocarbons also make a very small contribution. Share of fuel types in CO\textsubscript{2} emission follows similar pattern as in the case of other pollutants. Compared to the BAU case it is observed that for all years prior to the year of restriction share of domestic coal in the emission of all pollutants is higher, and in the terminal year it is mainly LNG and domestic gas that is only responsible for the emissions.

The annual total emissions of the pollutants over the planning horizon are tabulated in Table-A8.20 and are illustrated in Chart-8.10 through Chart-8.12. It is observed from the table that emissions of all the pollutants are higher than the BAU case over the planning horizon, except for the terminal year when the emissions of all pollutants are considerably lower. It may be noted that between the 1997 and the penultimate year TSP rises 2.74 times, SO\textsubscript{x} increases
2.74\times, \text{NO}_x \text{ grows 2.85times, \text{CO}_2 \text{ rises 2.97times and ash discharge increases 2.74times.}}

In the terminal year the emissions of pollutants reduce by 87-99%, with the maximum reduction noted for TSP and Ash, and the least reduction is observed for \text{CO}_2 emission. Notable is that, notwithstanding \text{CO}_2 emission restrictions in the terminal year, \text{CO}_2 \text{ emissions are observed to be the highest in the penultimate year and the reduction also least in the terminal year. The cumulative emission for the TSP is 9\% lower, \text{SO}_x \text{ about 10\% lower, \text{NO}_x \text{ 9.4\% less, \text{CO}_2 \text{ about 9.2\% less and ash discharge about 9\% lower than the BAU case.}}}

The present discounted emissions of the local pollutants are about 4\% less than the BAU case. \text{Thus, notwithstanding higher emissions than the BAU case along the development path, except for the terminal year, it is the substantially reduced emissions in the last year of the planning horizon that yields lower cumulative emissions.} \text{It is observed that share of coal, naphtha and domestic gas in the cumulative emissions of pollutants are higher than the BAU case. The shares of fuel types in the cumulative emissions of pollutants are depicted in Chart-8.9.}

\text{Therefore, this policy of restricting emission of \text{CO}_2 \text{ from 2011 is unattractive on several counts. The enormous size of the present value cost and the levelised average cost for the development trajectory questions the economic viability of the strategy. Substantial unserved energy partly explains the enormous size of this cost. It is observed that consequent upon the imposition of this emission restriction a substantial portion of the installed capacity remains idle, with the coal and naphtha based plants not generating at all, thereby adding to the economic burden of the system. Since cumulative emissions as an index of measure although quite appropriate for global pollutants, but for local pollutants this measure has little meaning. Thus, there appears to be a tradeoff between the local and the global pollutants along this optimal trajectory. It is essentially higher emissions of local pollutants along the development path till the penultimate year of the planning horizon that renders this policy quite unattractive. The positive aspect of this strategy may be considered to be the reduced dependence on imported fuels and the reduce requirement of reserve capacity. Hence it may be asserted that if the power sector is forced to comply with \text{CO}_2 \text{ emission restriction at the 1990 level from 2011, then the least cost way of doing so imposes tremendous burden on the economy and the environment.}}

\text{Sensitivity to CO21 Scenario}

\text{8(a). Variation of CO21 where \text{CO}_2 \text{ emission gradually declines from 2002 (CO22)}}

\text{This sensitivity scenario represents a situation where free emissions of \text{CO}_2 \text{ are allowed over the 9th plan, but constrained gradually from 2002 to eventually reach the 1990 level of emission in 2011.}}

\text{The negative growth rate of emission applicable from 2002 is determined endogenously within the exercise. With reference to \text{CO}_2 \text{ emission definition and restriction provided in chapter-3, the present scenario may be defined in the following manner:}

\text{CO}_2_t \text{ \forall t \text{ is defined in chapter-3;}}
In order to arrive at the dynamic emission restriction equation with endogenously determined
growth rate, the following derivation is used -

If \( A_0 \) is the emission level for the first year on which the negative growth rate would be used,
if \( A_n \) is the emission level to be eventually reduced to and reached in the final year,
if \( A_t \) is the emission level in year \( t \), and
if \( r \) is the growth rate (to be endogenously determined); then,

\[
A_0 (1 - r)^n = A_n,
\]
or,

\[
\left( \frac{A_n}{A_0} \right)^{1/n} = 1 - r
\]

i.e.,

\[
A_0 = A_0,
\]

\[
A_1 = A_n^{1/n} \cdot A_0^{1-1/n},
\]

\[
A_2 = A_n^{2/n} \cdot A_0^{1-2/n},
\]

then it follows by induction that,

\[
A_t = A_n^{t/n} \cdot A_0^{1-t/n}
\]

and,

\[
A_n = A_n.
\]

Therefore, taking cue from the above derivation, the emission restriction would require an
additional equation, which may be represented in the notational form of chapter-3 as,

No restriction on \( CO_2 \) emission for \( t \leq 5 \), and

\[
CO_2_t \leq \left( \frac{CO_2}{(T-5)} \right)^{(t-5)/(T-5)} \cdot \left( CO_2_{t=5} \right)^{1-\left( (t-5)/(T-5) \right)},
\]

for \( t > 5 \),

where \( CO_2 = CO_2_{t=1990} \), and \( t = 1, \ldots, T \).

The demand-supply balance constraints are once again relaxed to allow for unserved energy
and the cost of unserved energy is included in the objective function of the optimization
exercise. The binary variables representing whether a plant is in operation is also introduced.

Sensitivity Results

The results of the sensitivity analysis are tabulate in the comparative tables (Tables-S8.1 through Table-S8.14) presented in Appendix-8 (Continued).

The simulation result indicates massive reduction in cumulative emissions, with \( CO_2 \)
emission 45% less, TSP is 60% less, \( SO_x \) is 57% less, \( NO_x \) is 52% less and Ash discharge 59-60%
lower than the \( CO_2 \) case. The present discounted emissions of local pollutants are about 35-
40% lower than the \( CO_2 \) scenario.

The optimal capacity expansion plan indicates 3380MWs of coal thermal plants being
added (inclusive of 630MWs of imported coal-based plants), which is less than half of what is
added in \( CO_2 \) case. Substantial additions of LNG based combined cycle plants are envisaged
over the planning horizon, along with considerably large domestic gas and LNG based open-
cycle capacity additions. Consequential to large hydrocarbon additions, additions of renewable
projects are envisaged to be lower over the planning horizon. Since emission restrictions are
imposed from the 10th plan, massive LNG based combined-cycle capacity is added over the 10th
plan after some coal thermal plants are added over the 9th plan. Bulk of the total capacity
additions is, however, envisaged over the 11th plan period. The share of fuel types in the total
energy generation indicates declining share of coal over the last two plans and increasing
shares of domestic gas, LNG, hydro and wind projects over the same period. Naphtha based
generation after an initial increase over the 10th plan, declines over the 11th plan period. Further,
over the last few years of the planning horizon when emission restrictions tighten significantly it
is observed that naphtha and coal do not generate at all. Compared to the CO21 case, it is
observed that share of coal is relatively lower and hydrocarbon as well as wind and hydro are
relatively higher in this scenario. Notable is the significantly higher contribution of wind in total
generation over the terminal years of the planning horizon. The PLFs also indicate the declining
and extremely low utilization of coal thermal plants over the 10th and 11th plan periods, with the
Talcher coal-based plants not generating at all over the 11th plan. The PLFs of the gas and
LNG based plants indicate greater utilization over the 10th and 11th plans, although somewhat
decreasing over the 11th plan period. These are also reflected in the annual shares of fuel types in
the total fuel requirements. The unserved energy and load along the optimal development path
in this scenario is much higher than the CO21 case. It is observed that the unmet energy over
the 10th and 11th plans increases from 8978.14GWhs in 2004 to 73130.04GWhs in 2011. The
tradeoff between lower emission consequent upon the emission cap and the higher costs arising
from massive unserved energy is clearly evident. Thus, the present value system cost for this
development path is observed to be Rs.2055.31billion, which is about 165% higher than the
CO21 case. The levelised average cost is observed to be 218% higher than the CO21 case. The
present value cost of unserved energy is obtained as Rs.1743.7billion, which is about 295%
higher than the CO21 case and about 33.85times higher than the BAU case. These results
indicate that if CO2 emission restrictions are gradually imposed from the 10th plan, then it
appears that capacities have to be left idle and incur tremendous financial, economic and social
costs so as to conform to the emission standards.

The above analysis indicates that, faced with the increasing energy and load
requirements, stringent restrictions of ‘Grandfathered Emission’ standards are achievable only
at the expense of enormous unserved energy. The financial, economic and social costs of such
massive unserved energy poses to be a major stumbling block in the way of development
process. Since in the context of global pollutants cumulative emissions are more important, it is
observed from the above analysis that when CO2 emission cap is implemented from the terminal
year the costs are lower and cumulative emissions higher than when the restrictions are
gradually imposed from 2002. Moreover, in the context of emission cap only in the terminal year
of the planning horizon it is observed that emissions of pollutants are preponed and are much
higher than the reference case, thereby imposing tremendous burden on productivity, health and welfare. Although in view of this the gradual reduction of emission over a protracted period may be much more effective and viable, but on economic, financial and social considerations this is not at all acceptable. The gradual emission reduction over a protracted period makes the power sector development vulnerable to international pressures and factors, since the development process is to a great extent dependent on imported fuels and hydrocarbon, when hydro and renewable projects are constrained. Moreover, the social and economic costs of an enormous unmet energy and load are also very high. Thus, it appears that it is not at all suggestible to fix ambitious emission targets at a high abatement cost range and sacrifice potential economic growth and productivity. Therefore, the above analysis clearly supports that any effort towards global environmental management would require mobilization of enormous amount of capital resources, which again is an extremely difficult task for a resource scarce developing country. Since the responsibility of global damage to a great extent rests with the developed countries, therefore ability of the developing countries to mitigate and abate depends on the assistance from the developed countries, bilateral and multilateral donors and international organizations in the form of financial support and technology transfers.
Chart-8.1
Share of Fuel Types in Total Installed Capacity

Chart-8.2
Share of Each Fuel Type in Total Energy Generation
Chart-8.3
Share of Fuel Type in Base Mode Generation

Chart-8.4
Share of Each fuel Types in Intermediate Mode Generation
CHARTS for Quantitative CO₂ Restriction Scenario

Chart-8.5
Share of Each Fuel Types in Peak Mode Generation

Chart-8.6
Capacity Additions over the Plan Periods (MWs)
CHARTS for Quantitative CO₂ Restriction Scenario

Chart-8.7
Plant Load Factors

Chart-8.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-8.9
Share of Fuel Types in Cumulative Emission of Pollutants (TSP, SOx, NOx, CO2)

Chart-8.10
Annual CO2 Emissions
Chart-8.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-8.12
Total Annual Emission of ASH
(Million Tons)
Chart 8.13
Reserve Margins 'HOT' and 'COLD'

[Graph showing reserve margins from 1997 to 2011 with lines for SPIN. RESRV and RM COLD]
E. Policy Combinations / Packages

9. Policy Package (COMB)

As already mentioned in chapter-5, recent endeavours in development planning for the power sector indicates a shift towards an altogether new paradigm that emphasizes energy services as an index of development, rather than simply concentrating on supply side planning in isolation. This descending theory of power system planning, which has gained wide popularity recently, advocates that a comprehensive approach to power planning should integrate improvements in efficiency and quality of energy supply as well as use within the least cost investment planning exercise. Thus, effective capacity additions at least cost may be ensured through energy conservation and efficient performance of the entire system. Such an integrated approach to power planning may be quite attractive not only on economic and financial considerations, but may be environmentally quite beneficial as well. Such is the essence of the Integrated Resource Plan, where the objective is to consider all available resource options (centralized and decentralized, conventional and non-conventional, conservation and efficiency improvements on the supply and demand sides, etc.) in an integrated manner while planning for the power sector.

This scenario is an attempt at mimicking the Integrated Resource Plan, where utility driven DSM and improvements in T&D losses are considered, along with the presumption of increased efforts by the Government and the Board to encourage renewable options, into a single development strategy for the power sector. With the aim of making the supply options as exhaustive as possible the clean coal technologies are also assumed to be part of the available technology set. Thus, this policy paradigm is a combination of BAU, Renewable, CCT, T&D reform, and DSM scenarios.

Results

The simulation results for this hypothetical scenario are tabulated in Table-A9.1 through Table-A9.21 of Appendix-9.

The results indicate some interesting and favourable changes over the BAU scenario. Since the requirement of load and energy are much lower than the BAU case, it is observed that the total installed capacity increases only 2.92 times from 6735MWs in 1997 to 19696MWs in 2011. Capacity additions envisaged over the 9th, 10th and 11th plan periods are 506MWs, 540MWs and 7446MWs respectively. This shows that the capacity additions over the planning horizon are 3409MWs or about 15% lower than the BAU case. The optimal composition of capacity additions envisaged are 7000MWs of domestic coal thermal, 116MWs of domestic gas thermal, 1150MWs of LNG based capacity, 110MWs of hydro project at Jurala and
116MWs of renewable projects (including 66MWs of mini hydel projects). It is noted that imported coal, naphtha and washed coal options are not optimally selected; and amongst technologies and plants load centre plants, open-cycle technologies and clean coal technologies are optimally chosen.

The type, size and timing of the optimal capacity additions are tabulated in Table-A9.2 through Table-A9.4. Although compared to the BAU case less capacity additions are envisaged over all the plan periods, but it is the capacity additions over the 10th plan that are significantly lower in this scenario. Faced with capacity shortage and increasing gap between supply and requirement, it is observed that a 500MW pithead plants at Talcher is inducted along with some mini hydel projects in 1999, the earliest when the future plants are feasible to be inducted (by assumption). With substantially lower energy and load requirements over the 10th plan, it is observed that very little capacity is optimally added over this period. It may be noted that mini hydel projects are inducted on a regular basis, supported from wind projects from the 10th plan. However, substantial capacity additions are envisaged over the 11th plan period, with the preferred sequence of fuel types similar to the reference scenario. Thus, Talcher coal based pithead plants are first inducted and followed by pithead plants using Singareni coal, when constraints of availability from Talcher are encountered. However, with the limitations of production build-up from Singareni and the mounting energy/load requirements, domestic gas and LNG based combined-cycle capacities are inducted into the system. It is also observed that the major hydro project at Jurala is optimally inducted in the penultimate year of the planning horizon, otherwise brought online much earlier in the planning horizon for the other scenarios. This arises because the peak load requirements in this scenario over the 9th and 10th plans are much lower than the reference and other scenarios. Moreover, compared to the BAU case less capacity additions of all the fuel types are envisaged in this scenario, except for the renewable options that are significantly higher. Renewable projects appear to have optimally replaced the open-cycle gas options in the optimal capacity additions. The optimal capacity additions over the plan periods are illustrated in Chart-9.6.

Table-A9.6 presenting the shares of fuel types in total installed capacity indicates coal-based capacity to be the mainstay, followed by the hydro projects. The shares although similar to the BAU case for the first two plan periods, but over the 11th plan there are some discernible changes. The marginal changes with reference to the BAU case observed over the first two periods indicate slightly higher shares of coal and naphtha based options and lower share of hydro in the total installed capacity. Over the 11th plan it is observed that compared to the BAU case shares of domestic coal, naphtha, hydro and wind options are higher, while that of LNG is significantly less. Share of domestic gas is also observed to be marginally lower over the 11th plan relative to the BAU case. It is quite interesting to note that about 64% of the capacity additions are envisaged over the last three years of the planning horizon, and about 24% of the optimal capacity additions over the first two years of the 11th plan period. Therefore less
capacity requirement, significantly less gas (including LNG) based options in total capacity additions and postponement of capacity additions towards the terminal years of the planning horizon have obvious financial and economic advantages. These annual shares of the fuel types in the total installed capacity for the planning horizon are illustrated in Chart-9.1.

Outputs generated by the different plants at different load levels are tabulated in Table-A9.6 through Table-A9.8. Chart-9.3 illustrating the shares of fuel types in base mode generation indicates that the annual share of domestic coal in the base mode is maximum over the planning horizon and is supplemented by hydro significantly. However, the share of hydro declines gradually over the planning horizon. Naphtha and gas also makes a small but steady contribution to the base mode of generation. LNG based combined-cycle plants generate in the base mode only over the last two years of the planning horizon, but indicates an increasing share in the total contribution to this mode. Compared to the BAU case, it may be noted that share of coal is significantly higher, especially over the 10th and 11th plan periods. Share of naphtha is noted to be slightly higher and share of hydro marginally lower in the base mode relative to the BAU scenario. Share of LNG in the base mode is distinctly lower in this scenario as compared to the BAU case. Chart-9.4, illustrating the shares of fuel types in the intermediate mode, indicates that hydro mainly contributes to this mode and is supplemented by coal towards the terminal years of the planning horizon. Compared to the BAU case it is observed that shares of both hydro and wind in the intermediate mode is higher in this scenario. Chart-9.5 illustrating the shares of fuel types in the peak mode indicates that hydro has the maximum share in this mode. Domestic coal over all the plan periods, naphtha over the 11th plan and to a small extent wind option over the entire planning horizon supplements hydro in the peak mode generation. Domestic gas and LNG makes little contribution to the peak mode. Relative to the BAU scenario, it is observed that share of naphtha, wind and hydro are higher and share of domestic gas and LNG are lower.

Gross generation of electricity tabulated in Table-A9.9 indicates that energy generation increases 2.62 times from 37421.59GWhs in 1997 to 97907.59GWhs in 2011. For obvious reasons gross energy generation and energy generation at busbar are lower than the BAU case. Compared to the BAU case it is observed that the shares of future plants in total energy generation at busbar are lower in this scenario. However, this share of future plants in total generation at the busbar increases over the planning horizon, especially over the 10th and 11th plan periods. Further, relative to the BAU case, share of auxiliary consumption in total generation is observed to be marginally higher in this scenario. Annual shares of fuel types in total energy generation are tabulated in Table-A9.10 and illustrated in Chart-9.2. Amongst the fuel types it is observed that domestic coal contributes most to the total energy generation, and is observed to increase over the plan years except for the last two years of the planning horizon.
Annual share of naphtha in the total energy generation increases gradually over the 9th plan, but declines over the 10th and 11th plans. LNG generates only in the last two years of the planning horizon, but shows an increasing trend. Domestic gas is observed to contribute little over the planning horizon, regularly, but with occasional fluctuations. **Compared to the BAU case, it is observed that annual shares of domestic coal, hydro and naphtha in total generation are higher, especially over the 10th and 11th plans. LNG is observed to contribute much less and for fewer years than the BAU case. Moreover, except for a few years, share of domestic gas in total generation is observed to be much less than the BAU case.** Thus, with the absence of imported coal, LNG contributing very little over the planning horizon and domestic gas also contributing less, this scenario scores significantly over the other scenarios, including the reference, on economic considerations.

The PLFs tabulated in Table-A9.11 and depicted in Chart-9.7 shows high capacity utilization of Talcher coal and Singareni coal plants. Domestic gas based options are also envisaged to have high capacity utilization, except for few years between the terminal years of the 9th plan and early 10th plan. LNG based combined-cycle plants, although producing only for the last two years, are observed to have high capacity utilization in the years when they produce. Hydro and wind options have relatively low capacity utilization, mainly constrained by their energy potential, contributing mainly to the intermediate and peak modes. Naphtha options, except for the initial few years, have almost the same capacity utilization as that of the hydro options. The overall PLFs are observed to be slightly lower for the 10th plan and slightly higher for the 11th plan, relative to the BAU case. **It is also observed that, except for a few years in the 11th plan, the reserve capacity requirements to ensure minimum guarantee condition are higher than the BAU case. It is further noted that the annual standby utilizable capacity required as reserve in 'cold' condition is larger and that in 'hot' condition smaller than the BAU case.** This implies that the development path obtained for this scenario is less resilient to sudden outages and the real cost of maintaining a larger standby capacity is also higher. The reserve capacity requirements are presented in Table-A9.15 and illustrated in Chart-9.13.

The total fuel requirement per annum and their availability are tabulated in Table-A9.12 and Table-A9.13. The share of various fuels in the total fuel requirement are tabulated in Table-A9.14 and depicted in Chart-9.8. These figures indicate that domestic coal accounts for the maximum share in the total fuel requirement for the entire planning horizon. For most of the years over the 10th and 11th plan periods, the share of coal exceeds that obtained for the reference scenario. Share of naphtha in total fuel requirement although declining over the planning horizon exceeds the shares obtained for the BAU case. Moreover, relative to the BAU scenario, the share of LNG in total fuel requirement for this scenario is lower. **It may be, however, noted that, because of lower energy and load requirement and lower generation, total**
fuel requirement for this scenario is considerably lower than the BAU case. Therefore, notwithstanding increased shares of polluting fossil fuels in total energy generation and fossil fuel requirement, the environmental fallout may not be damaging. Besides the economic and cost advantages arising from less dependence on imported fuel makes this development strategy quite attractive.

It is observed that the present discounted value of the system cost at Rs.346.4 billion is about 12.7% lower and the levelised average cost at 1.02 Rs/KWh is about 4% lower than the BAU scenario. It is also observed that the levelised average cost of generation by future plants at 1.14 Rs/KWh is about 9% lower than that envisaged for the BAU case, arising from lower capital and fuel costs. Influenced by energy conservation mainly driven by DSM and supplemented by T&D rehabilitation, it is observed that the present value cost of unserved energy at Rs.50.08 billion is lower than that of the reference case. Thus, with reference to cost for this development trajectory this strategy has a distinct advantage over the other strategies, notwithstanding the higher real cost arising from a larger utilizable capacity being set aside as standby reserve capacity for ensuring minimum guarantee condition.

The shares of the fuel types in annual emissions of pollutants are tabulated in Table-A9.16 through Table-A9.19. Domestic coal continues to be responsible for fugitive emission of TSP. Domestic coal is also mainly responsible for emission of SO\(_x\), with extremely small contribution made by naphtha. Compared to the BAU case, shares of fuels in the total annual emission of SO\(_x\) and TSP are same except for the terminal years, when in this scenario the share of domestic coal is greater. With reference to fugitive NO\(_x\) emission it is observed that domestic coal is mainly responsible for emission and its share exceeds that of the BAU case. Naphtha and gas (domestic and LNG) are also observed to make some contribution to NO\(_x\) emission. Compared to the BAU case, it is observed that although the share of naphtha in NO\(_x\) emission is almost same, but the share of gas is marginally lower and the share of LNG significantly lower in this scenario. With reference to annual CO\(_2\) emission it is observed that over the 9th and 10th plans the shares of domestic coal, gas and naphtha are very similar to the BAU case, with only marginal differences in some years. Domestic coal is mainly responsible for CO\(_2\) emission and gas and naphtha make small contributions. Over the 11th plan it is observed that relative to the BAU case shares of coal and naphtha are higher and shares of LNG and gas are lower in this scenario.

The annual emissions of the pollutants are tabulated in Table-A9.21 and illustrated in Chart-9.10 through Chart-9.12. These indicate that over the planning horizon emission of TSP rises 2.74 times, SO\(_x\) rises 2.74 times, NO\(_x\) rises 2.80 times, CO\(_2\) rises 2.86 times and Ash discharge increases 2.74 times. The trends of emissions observed are almost similar to the BAU case, but the rate of increase through the 9th and the early 10th plan are more moderate in this scenario. Further it is observed that over the latter half of the 10th plan, rate of increases
registers a sharp rise and the emission trajectory becomes quite steep compared to the BAU case. This continues through the terminal years of the 11th plan, until the emissions almost stabilize from 2010 onwards. Thus, compared to the BAU case the steep rate of increase of emission begins early and stabilizes late in the planning horizon. However, the annual emissions of pollutants are lower than the BAU case and find its reason in lower generation. It is higher share of domestic coal and naphtha in generation that dampens the emission reductions significantly. The cumulative emissions of pollutants for this scenario indicate that emission of TSP is 9%, SOx is 9.7%, NOx is 10.6%, CO2 is 11.4% and Ash discharge is 9% lower than the emissions obtained for the BAU case. Shares of fuel types in cumulative emissions of pollutants indicate higher shares for domestic coal and naphtha and lower shares for gas and LNG relative to the BAU case. These shares are tabulated in Table-A9.20 and depicted in Chart-9.9.

This policy driven scenario depicts an 'ideal' situation, where capacity additions, investment, generation and damaging levels of emissions appear to have been postponed to some later date beyond the planning horizon. Moreover, for a power sector constrained by the availability of indigenous fuel and financial resources, a development strategy that is consistent with traditional fuel policy with minimal dependence on imported fuels is obviously quite attractive. Since the development pattern within the 'new' policy regime yields significant cost and environmental improvements, therefore the need for penalties and taxes to further reduce emissions at higher cost is only justifiable under very stringent emission standards. Thus, an integrated development strategy in the absence of taxes and penalties reflects an 'optimistic' regimen for sustainable development of the power sector. However, notwithstanding the obvious economic, financial and environmental benefits, this 'ideal' strategy is extremely difficult to actually realize and implement. Major structural, organizational and institutional changes are involved in the actual realization of this strategy. Consequently, the individual options are to be prioritized and efforts made to overcome the existing impediments so as to realize their true potential. Alongside it is necessary to initiate the reform process and expedite the structural, organizational and institutional changes necessary to realize the vision of a sustainable development of the power sector.
CHARTS for Policy Package Scenario

Chart-9.1
Share of Fuel Types in Total Installed Capacity

Chart-9.2
Share of Each Fuel Type in Total Energy Generation
CHARTS for Policy Package Scenario

Chart-9.3
Share of Fuel Type in Base Mode Generation

Chart-9.4
Share of Each fuel Types in Intermediate Mode Generation
CHARTS for Policy Package Scenario

Chart-9.5
Share of Each Fuel Types in Peak Mode Generation

Chart-9.6
Capacity Additions over the Plan Periods (MWs)
CHARTS for Policy Package Scenario

Chart-9.7
Plant Load Factors

Chart-9.8
Share of Each Fuel Class in Total Fuel Requirements
Chart-9.9
Share of Fuel Types in Cumulative Emission of Pollutants (TSP, SOx, NOx, CO2)

Chart-9.10
Annual CO2 Emissions
Chart-9.11
Total Annual Emission of Local Pollutants
(Thousand Tons)

Chart-9.12
Total Annual Emission of ASH
(Million Tons)
Chart-9.13
Reserve Margins-'HOT' and 'COLD'

- SPIN. RESRV
- RM COLD

Reserve Margins (MWs)

Years

1997 1999 2001 2003 2005 2007 2009 2011
times respectively over the planning horizon. Consequently, as tabulated below, the cumulative emissions of these pollutants envisaged are also phenomenal. Such colossal increases in the levels of pollution not only have a direct adverse effect on the environment/ecology, health and productivity, but also unleashes a chaotic torrent of destruction all around. The optimal results for this development trajectory indicate proliferation of thermal power plants and generation, with the predominance of coal based capacity expansion and generation. This further implies the need to cater to the huge requirements of water for these thermal power plants and to the requirements of land for the plants as well as for ash disposal. However, with significantly large capacity expansion of coal thermal plants taking place at mine-mouth, availability of water may prove to be a very great impediment. Large areas of land required for ash disposal may be quite difficult to find and the problem is only exacerbated by the fact that land utilised for ash disposal loses its original use and value, and is often quite expensive to reclaim. The adversity of the situation is significantly enhanced by the associated fuel lifecycle and mining. Moreover, being at the core of the global environmental policy debate, the massive increase in CO$_2$ emission envisaged and its high growth rate are matters of serious concern. However, it may be noted that the emission of pollutants increases over the first two plans of the planning horizon but stabilises over the terminal plan period. This phenomenon is quite marked for local pollutants, while for CO$_2$ emission the rate of increase falls significantly over the final plan period. This arises from the changing composition of fuel combustion for the generation of electricity, influenced by the fuel availability and infrastructural constraints. Notwithstanding this rate reduction and stabilisation of emissions, the absolute level of emission increases are quite substantial for the Business-as-Usual development of the power sector. The simulation results indicate 610MWs, 3130MWs and 8145MWs of capacity additions over the 9th, 10th and 11th plan periods respectively. Such massive increases in capacity envisaged over the plan periods involve enormous investment requirements. The system cost, which includes all fixed and variable costs involved in planning for the power sector, and the levelised average cost obtained for this policy driven scenario are Rs387.6billion and 1.03Rs/KWh respectively.

However, several important changes are inevitable as the economy is at present cruising on the waves of liberalisation. Notable among such changes is the gradual transition towards an economic cost regime. The process of decontrolling fuel prices is already underway, with the government allowing coal companies to fix prices of D, E, F and G grades of non-coking coal. In the case of hydrocarbons too the government has decided to replace the existing pricing policy with import parity driven system, thereby delinking from the crude oil

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198 In February 1997, the government decided to deregulate the prices of grade-D non-coking coal with immediate effect. The decontrol of E, F and G grade coals is also on the anvil.