DETERMINATION OF OPTIMUM UNIT CAPACITIES OF FUTURE COAL POWER PLANTS IN SRI LANKA

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Declaration

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Abstract

In Sri Lanka, future generation plan includes number of coal power plants according to Long Term Generation Expansion Plan (LTGEP) prepared by Ceylon Electricity Board. Proportion of coal power generation is significant and hence their technology and unit size are important parameters when planning future coal power plants. Therefore, this study focuses on a methodology to determine optimum unit size of future coal power plants in accordance with LTGEP.

System stability constraint is identified as the limiting factor for larger units over conventional 300 MW size. In order to determine the constraint, off peak demand forecasting has been performed for next 20 years. Out of two forecasting methods, multiple regression analysis method is selected and based on off peak demand forecast, stability constraint is determined.

Technologies used for coal power generation are studies along with their advantages and limitations. High efficient supercritical technology is more focused and alternative options have been considered for proposed coal power units in LTGEP considering determined constraint. Accordingly, two cases are selected for financial analysis.

Discounted cash flow analysis is carried out for each case in order to compare supercritical single unit instead of two equal sized advanced subcritical units. Due to long project life time, constant cost basis is used to minimize error of financial forecast. NPV, IRR and LOCE figures were calculated and sensitivity is analysed against fuel price and selling price. Results show that high efficient supercritical unit is more economical than smaller units even under partial load operation condition at off peak period.

Therefore, high efficient supercritical plant is recommended considering other driving factors such as reduction in hazardous emissions, ash products and environmental factors. Furthermore, findings of this study can be used for other technologies as well.

Key words: unit size, regression analysis, supercritical, off peak demand forecasting

Dedication

I dedicate this thesis to my loving parents, who dedicate their life to raise me in higher level and to my ever loving wife.

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LIST OF ABBREVIATIONS

Abbreviation	**Description**
ASUB	Advanced Sub critical
BFBC	Bubbling Fluidizing Bed Combustion
CEB	Ceylon Electricity Board
CFB(C)	Circulating Fluidizing Bed (Combustion)
DCF	Discounted Cash Flow
GDP	Gross Domestic Production
GHG	Green House Gas
HHV	Higher Heating Value
HP	High Pressure
ID	Industrial Demand
IEA	International Energy Authority
IRR	Internal Rate of Return
LHV	Lower Heating Value
LNG	Liquid Natural Gas
LCOE	Levelised Cost of Electricity
LTGEP	Long Term Generation Expansion Plan
MAD	Mean Absolute Deviation
MAPE	Mean Absolute Percentage Error
MS	Microsoft
MSE	Mean Square Error
NPV	Net Present Value
O & M	Operation and Maintenance
PV	Present Value
SC	Supercritical
USD	United State Dollar
WASP	Wien Automatic System Planning Package

Chapter 1
INTRODUCTION

Electricity plays a foremost role in any country as a major source of energy, where economic growth is directly co-related with electricity demand. Moreover, in day to day life, people are dependent on electricity in every aspect. With increasing population and industrial development electricity demand is expected to be growing above 6% annually [1], where as sector utility entities need planning for decades ahead to meet the future electricity demand.

1.1 Future Candidate Coal plants

In Sri Lanka, Ceylon Electricity Board (CEB) is responsible for future generation planning in order to meet increasing electricity demand. According to the CEB Long Term Generation Expansion Plan (LTGEP 2013-2032), coal will be the major source of power with its share reaching almost 70% by the year 2025 (Base case plan). Although Sri Lanka is new to coal power plants, it is one of the widespread mature technologies for economical and reliable power generation worldwide. According to this plan, except 2*250 MW coal plants (in 2018), all other coal plant additions are in 300 MW unit size. This fact is evident in LTGEP (2015-2034) also as shown in the Table 1.1.

1.2 Unit Size of Coal Power Plant

Unit size of a coal power plant is an important parameter linked with overall plant efficiency, technology, fuel cost, capital investment etc. Coal plant unit sizes spread in a wide range, as world trend is moving towards high efficiency larger unit sizes. Furthermore, different unit capacities are correlated with different types of technologies. Compared to matured subcritical technology, higher efficient supercritical and ultra supercritical technologies are attached to larger units with minimum unit capacity of 500MW according to literature review. Moreover, higher efficient technologies consume lesser fuel to produce same energy output, which in turn reduces the emissions and ash products. However, capital cost and unit capacity are limiting factors to be considered.

Table 1.1: Future coal power plant additions

YEAR	RENEWABLE ADDITIONS	THERMAL ADDITIONS	THERMAL RETIREMENTS	LOLP %
2015	-	4x15MW CEB Barge Power Plant	4x15MW Colombo Power Plant 14x7.11MW ACE Power Embilipitiya	0.077
2016	-	-	-	0.150
2017	*35MW Broadlands HPP* *120MW Uma Oya HPP*	-	4x17MW Kelanitissa Gas Turbines	0.175
2018	**100MW Mannar Wind Park Phase I**	**2x35MW Gas Turbine**	8x6.13MW Asia Power	0.299
2019*	-	**1x35MW Gas Turbine**	4x18MW Sapugaskanda Diesel	1.140
2020	*31 MW Moragolla HPP* **15MW Thalpitigala HPP**** **100MW Mannar Wind Park Phase II**	**2x250MW Coal Power Plants Trincomalee Power Company Limited**	4x15MW CEB Barge Power Plant 6x5MW Northern Power	0.164
2021	**50MW Mannar Wind Park Phase II**	-	-	0.360
2022	**20MW Seethawaka HPP***** **20MW Gin Ganga HPP**** **50MW Mannar Wind Park Phase III**	**2x300MW New Coal Plant – Trincomalee -2, Phase – I**	-	0.015
2023	**25MW Mannar Wind Park Phase III**	*163 MW Combined Cycle Plant (KPS – 2)*$^{+}$	163MW AES Kelanitissa Combined Cycle Plant^{++} 115MW Gas Turbine 4x9MW Sapugaskanda Diesel Ext.	0.096
2024	**25MW Mannar Wind Park Phase III**	**1x300MW New Coal plant – Southern Region**	-	0.040
2025	**1x200MW PSPP***** **25MW Mannar Wind Park Phase III**	-	4x9MW Sapugaskanda Diesel Ext.	0.028
2026	**2x200MW PSPP*****	-	-	0.003
2027	-	**1x300MW New Coal plant – Southern Region**	-	0.002
2028	-	-	-	0.010
2029	-	**1x300MW New Coal plant – Trincomalee -2, Phase – II**	-	0.007
2030	-	**1x300MW New Coal plant – Trincomalee -2, Phase – II**	-	0.005
2031	-	-	-	0.029
2032	-	**2x300MW New Coal plant – Southern Region**	-	0.003
2033	-	-	165MWCombined Cycle Plant (KPS) 163MWCombined Cycle Plant (KPS–2)	0.142
2034	-	**1x300MW New Coal plant – Southern Region**	-	0.118
Total PV Cost up to year 2034, **US$ 12,960.51 million** [LKR 1,704.96 billion]$^{+}$				

Source: Base case plan LTGEP (2015-2034)

1.3 Research Objectives

This research aims to determine the optimum unit capacities of future coal power plants in Sri Lanka. Along with the unit size, suitable technology is considered from the available technological options. Cost benefit analysis is performed to determine the optimum unit capacity for selected plant addition according to LTGEP.

1.4 Methodology

This research is divided in to four main sections and its design is as follows.

1.4.1 Off peak Demand Forecasting

<u>System stability constraint</u>

At a given time,

Maximum unit dispatch = x% of system demand. (Assumption : x=30)

Any power generation unit should satisfy this constraint to maintain the stability of the power system. x value depends on power system characteristics and it is assumed to be 30% throughout this study.

During off peak period larger units have to de-rate to meet this constraint, as minimum value of this constraint is recorded during off peak period. In order to find the maximum allowable unit dispatch at off peak (or stability constraint at off peak), future off peak demand forecast is required. For that, time series and regression forecasting methods are used.

1.4.1 Analysis of Unit Capacity/ Technology Options

Compared to matured subcritical technology, higher efficient supercritical/ ultra supercritical are being penetrated to the industry. These higher efficient units are larger in capacity compared to their successors. In that scenario, different available technologies along with their unit sizes are discussed analysing advantages and disadvantages. Based on that, several available options are proposed for financial analysis.

1.4.2 Financial Analysis

Cash flow analysis is carried out for those options separately and NPV, IRR indices are calculated. Apart from that, levelised cost of electricity is used to compare overall costs. Eventually, sensitivity analysis shows how above indices vary with fuel price and tariff.

1.4.3 Conclusion and Recommendations

Finally, optimum unit capacity and technology option is concluded based on the financial performance and other non financial factors.

Chapter 2
OFF PEAK DEMAND FORECASTING

2.1 Introduction

Unit size of a coal power plant is bound by system stability constraint. i.e. at any given time, maximum unit dispatch is limited to x% (which is assumed 30%) of system demand. All power generating units should satisfy this practical limitation in order to maintain stability of the power system. Control engineer at the system control centre makes sure that every generator unit connected to the grid satisfies this condition at all times and dispatch the plants accordingly. In case of a coal plant, it used to be run at rated capacity all the time due to plant characteristics and economy. However during off peak period (when the stability limit is lowest), if unit rated output exceeds the stability constraint, unit has to be de loaded to satisfy the constraint. Indeed, going for higher unit capacities leads to partial load operation during lowest demand period of the day. This has direct impact to plant efficiency, machine depreciation, life time and unit fuel cost in addition to capacity loss. Therefore, in order to analyse feasible unit capacity options, stability constraint has to be determined for the considered future time horizon. This requires off peak demand forecasting to be carried out first.

2.2 Off peak Demand Forecasting

Forecasting is making projections about the future using past and present data [2]. It is often used in many fields with ample practical applications. In long term generation expansion plan, annual energy demand is forecasted using econometric modelling, which is used as an input of WASP package to formulate optimum generation expansion plan. Off peak demand is not analysed as it is less important to the plan. According to the literature survey, no off peak demand forecasting or methodology has been identified for the considered time horizon, which is required for further proceedings of this study. Therefore, this chapter focuses on off peak forecasting using statistical methods and deriving the future forecast.

2.3 Approach for Off peak Forecasting

There are number of forecasting methods available in the literature, which are used for wide range of practical applications. Selecting a particular method is based on nature of application, level of complexity, availability of data, accuracy of results, duration of forecasting etc [3].

2.3.1 Literature Review

According to the literature review, no specific forecasting exercise/ forecasting methodology is found with respective to off peak demand of the power system. Generation planning unit of CEB is performing macro level planning in long term basis, where annual electricity demand (total and sector wise), load factor and peak demand forecasts are available for the next 20 years. Therefore in this study, suitable methodology has been developed to forecast annual off peak demand after analysing available different methods.

For this particular application two prominent forecasting methods [3] have been selected considering the above factors and they are as follows.

- Time series method
- Regression method

2.3.2 Time Series Method

In time series based forecasting, past data patterns are analysed and they are used to forecast the future data. Irrespective of other factors, time is recognized as main independent variable to predict the future. The essence of the method is to recognize that the demand occurs over time in patterns that repeat themselves [4]. Moreover, past annual off peak demand data plot (Figure 2.2) also shows a particular pattern, which could be used in this forecasting method.

2.3.2.1 Theoretical Equations used in Time Series based Forecasting

In this case, Holtz winter method which is also known as triple exponential smoothing is adopted for forecasting. This method could integrate both trend and seasonality factors to the forecast [5]. Here, multiplicative seasonality is used [6] as amplitude of the cycle is increasing with the base over the time.

$$s_0 = x_0$$

S is smoothed observation. Initially real observation x_0 is taken as s_0.

At any given time t smoothed observation s_t can be derived as follows.

$$s_t = \alpha \frac{x_t}{c_{t-L}} + (1-\alpha)(s_{t-1} + b_{t-1})$$

0< α<1, α- smoothing factor,

Trend component of the forecast is analysed using trend factor- b as,

$$b_t = \beta(s_t - s_{t-1}) + (1-\beta)b_{t-1}$$

0<β<1, β- trend smoothing factor

Likewise seasonality component is governed by seasonal index - c as,

$$c_t = \gamma \frac{x_t}{s_t} + (1-\gamma)c_{t-L}$$

0<γ<1, γ- seasonal smoothing factor

L – no. of periods per cycle

Accordingly final forecast is given by

$$F_{t+m} = (s_t + mb_t)c_{t-L+m}$$

m - Period index

2.3.2.2 Inputs to the Forecast : Past Off peak Demand

As past data is an essential input for any forecast, past off peak demand data is collected. Past records are available since 2006, which are used for this study. Daily minimum off peak demand is averaged over one month to find out average minimum off peak demand of a particular month as shown in Figure 2.1. Accordingly, annual average of minimum off peak demand is derived using monthly off peak demand data.

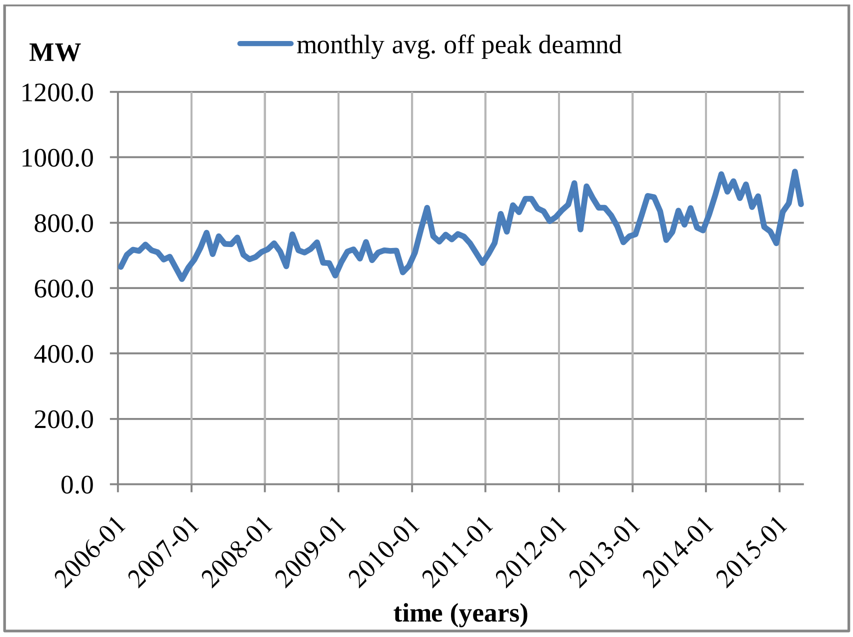

Figure 2.1 : Past monthly average off peak demand

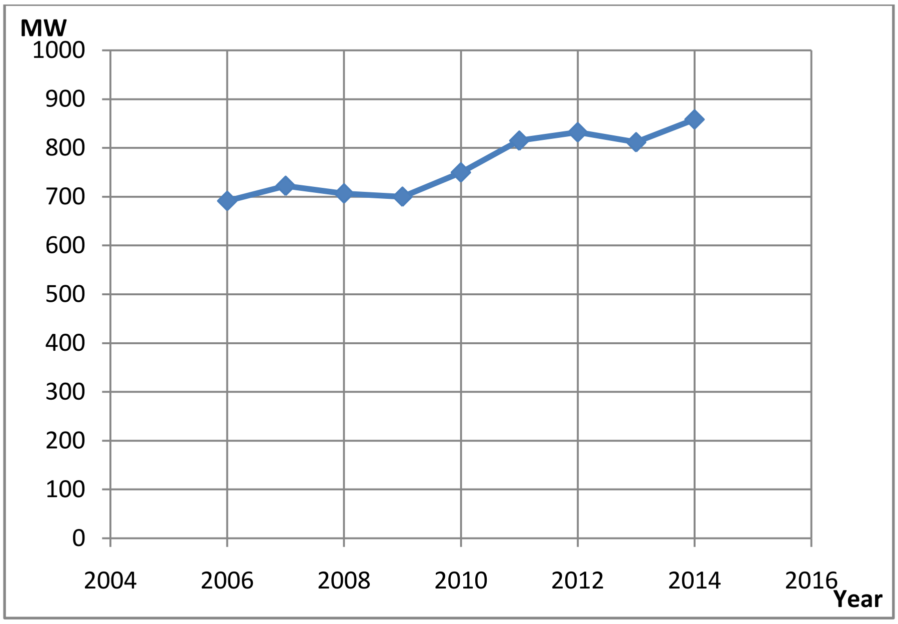

Figure 2.2 : Past annual average off peak demand

2.3.2.3 Setting up Initial Values and Forecasting

Initial smoothing factor (s_0) is calculated using average of the first 12 month data [7].

Initial trend factor b_0 is taken as,

$$b_0 = \frac{1}{L}\left(\frac{x_{L+1} - x_1}{L} + \frac{x_{L+2} - x_2}{L} + \cdots .. + \frac{x_{L+L} - x_L}{L}\right)$$

If data available for N number of cycles, initial seasonality indexes c_i is given by;

$$c_i = \frac{1}{N}\sum_{j=1}^{N}\left(\frac{x_{L(j-1)+i}}{A_j}\right) \quad \text{for all i = 1,2,....,L}$$

A_j is the average of data x in j[th] cycle.

2.3.2.4 Results of Triple Exponential Smoothing based Forecasting

Miscrosoft Excel software package is used for this forecasting. α,β and ɤ coefficients are estimated to minimize Mean Square Error (MSE) of the data set [7]. MS Excel solver function is used to calculate these coefficients. In order to continue the future iterations, it is assumed that at a given future time t, $F_t = x_t$.

Solver function outputs are as follows.

MSE_{min}=900.7954

α = 0.687584466

β = 0

γ = 1

Using above coefficients, future forecast is calculated and shown in Table 2.1.

Table 2.1 : Off peak demand forecast using time series method

Year	Off peak forecast (MW)	Stability constraint-30% (MW)
2015	900.37	270.11
2016	912.48	273.74
2017	920.74	276.22
2018	915.39	274.62
2019	1008.56	302.57
2020	1033.14	309.94
2021	1044.98	313.49
2022	1009.75	302.93
2023	1138.31	341.49
2024	1171.85	351.56
2025	1186.66	356.00
2026	1114.46	334.34
2027	1285.42	385.63
2028	1329.87	398.96
2029	1348.22	404.47
2030	1230.63	369.19
2031	1452.24	435.67
2032	1509.88	452.96
2033	1532.45	459.74
2034	1359.49	407.85

2.3.3 Regression Analysis

2.3.3.1 Introduction to Regression Analysis

Regression analysis is a process for estimating the relationships among variables which is widely used for forecasting. It focuses on the relationship between a dependent variable and one or more independent variables, called regression function. More specifically, regression analysis helps to understand how the typical value of the dependent variable changes when any one of the independent variable is varied, while the other independent variables are held fixed. Regression analysis also could be used to understand which independent variables are related to the dependent variable, and to explore the forms of these relationships between independent and dependent variables.

To use regression analysis for prediction, data collected on the variable that is to be predicted, called the dependent variable or response variable, and on one or more variables, whose values are hypothesized to influence it, called independent variables. In the estimation step, parameters are chosen so as to optimize the fit of the function. Once regression function is formulated, values of the independent variables are input to the parameterized function to generate predictions for the dependent variable.

2.3.3.2 Theoretical Equations of Multiple Linear Regression Analysis

Simple linear regression is used when there is only one independent parameter. $y_i = mx_i + c$ linear equation could be taken as the basic where 'm' and 'c' need to be found. Here,

$$m = \frac{\sum(x_i - \bar{x})(y_i - \bar{y})}{\sum(x_i - \bar{x})^2}$$

$$c = \bar{y} - m\bar{x}$$

When the number of independent variables is more than one, multiple regression analysis needs to be used. The multiple linear regression equation could be written as,

$$F_{t+1} = f(x)_t$$

$$f(x) = a + b_1x_1 + b_2x_2 + b_3x_3 + \cdots + b_nx_n$$

F- forecasted value

a,b–regression coefficients

This also can be written in vector form as [2],

$$y = X\beta + u,$$

Where $y = (y_1, \ldots, y_n)$ is the data vector consisting of n observations on the dependent variable, X is an $n \times (p+1)$ matrix of independent variables, $\beta = (\beta_0, \ldots, \beta_p)$ is a $(p+1)\times 1$ vector of regression parameters, assumed to be non random and $u = (u_1, \ldots, u_n)$ is an $n\times 1$ vector of random errors. Indicating the columns of the X matrix by $x_0, \ldots, x_p$, each column x_j gives the n values of the j^{th} independent variable, corresponding to the n observations in y.

The coefficient β_j measures the change in the regression function**,**

$$E[y \mid X] = X\beta = \sum_{k=0}^{p} x_k \beta_k$$

Which corresponding to a unit change in the j^{th} independent variable, if the model is accurate, and all other independent variables are held constant.

To estimate regression coefficient (β) from the observed data (y), 'the least square estimator' can be used. The least square estimator is the value of β^* which minimizes the criterion function,

$(y - X\beta^*)'(y - X\beta^*)$ which has a solution given by $b = (X'X)^{-1}X'y$.

The j^{th} entry b_j is the coefficient of x_j in the fitted model,

$$\hat{y} = Xb = \sum_{k=0}^{p} x_k \beta_k .$$

Therefore b_j can be taken as an estimate of the change in the expected value of the dependent variable y, corresponding to a unit change in the independent variable x_j, if all other independent variables are held fixed, assuming the model is correct [8].

2.3.3.3 Coefficient of Correlation (R)

The coefficient of correlation denoted by R measures the strength and the direction of a linear relationship between two variables. The mathematical formula for computing R for simple linear regression is called Pearson's formula.

$$R = \frac{n\sum xy - (\sum x)(\sum y)}{\sqrt{n(\sum x^2) - (\sum x^2)^2}\sqrt{n(\sum y^2) - (\sum y^2)^2}}$$

x – data points of independent variable

y – observation of the response of dependent variable

n – number of pairs of data

The value of R is such that -1 < R < +1. The + and – signs are used for positive linear correlation and negative linear correlation, respectively.

If x and y have a strong positive linear correlation, R is close to +1. R value of exactly +1 indicates a perfect positive fit. If R value is in between 0 and +1 it indicates a relationship between x and y variables such that as values for x increase, values for y also increase. Likewise, if x and y have a strong negative linear correlation, R is close to -1. Furthermore, if there is no linear correlation or a weak linear correlation, R is close to 0. A value near zero means that there is a random, nonlinear relationship between two variables.

R^2 is a statistical parameter, which measures goodness of fit between regression line and the real data points. R^2 value lies in between 0 and +1 whereas R^2 of 1 indicates that the regression line perfectly fits the data. A value such as $R^2 = 0.9$ may be interpreted as ninety percent of the variance in the response variable (y) could be explained by the explanatory variables (x) [2].

2.3.3.4 P -Value

The p-value for each term tests the null hypothesis that the coefficient is equal to zero (no effect). A low p-value indicates that one could reject the null hypothesis [7]. In other words, a predictor that has a low p-value (i.e. insignificant) is likely to be a meaningful addition to the model, because changes in the predictor's value are related to changes in the response variable. Conversely, a larger p-value (i.e. significant) suggests that changes in the predictor are not associated with changes in the response.

Generally, 95% significance level is assumed, which requires p values need to be lesser than 0.05.

2.3.3.5 F- Test of Overall Significance

F-test in regression compares the fits of different linear models. Unlike t-tests that could assess only one regression coefficient at a time, the F-test could assess multiple coefficients simultaneously. The F-test of the overall significance is a specific form of the F-test. It compares the given model with intercept only model. i.e. regression model that contains no predictors .The hypotheses for the F-test of the overall significance are as follows:

Null hypothesis: The fit of the intercept-only model and given model are equal.

Alternative hypothesis: The fit of the intercept-only model is significantly reduced for given model.

If the value for the F-test of overall significance test is less than specified significance level, the null hypothesis could be rejected and conclude that the given model provides a better fit than the intercept only model.

2.3.3.6 Methodology

In multiple regression analysis, firstly, explanatory variables need to be defined. Annual average of minimum off peak demand (MW) is the dependent variable which needs to be forecast. Independent variables selected are likely to be closely related to dependent variable. In this study five variables are used namely,

- Industrial demand
- Annual demand
- Peak demand
- GDP
- Industrial sector GDP

It is assumed that industrial loads are prominent during off peak hours of the day. In addition, street lighting load also can be identified, which is less likely to vary with time. As GDP is a macro economic indicator which is closely related to electricity demand [1], total GDP and industrial sector GDP are selected. Annual demand and peak demand are the other important parameters to be analysed.

Accordingly, correlation between those parameters and the desired dependent variable is analysed using past data available. Annual demand, peak demand data are obtained from LTGEP 2015-2034 whereas GDP data are obtained from central bank reports. Industrial demand statistics are obtained from CEB. To develop the model, stepwise regression analysis is used [9]. In this method, initially each independent variable (X) is assessed against dependent variable (Y). Accordingly, most defining variable (say X^1) is selected which has highest R^2 and lowest P value. In the next step, each variable and X^1 combination are tested to satisfy test criteria. If it is done, iteration moves to third step or else stops at this point. Basically, this process continues until any tested variable doesn't improve existing relationship furthermore.

2.3.3.7 Results of Regression Analysis

Stepwise regression analysis is performed using MS Excel software package, regression data analysis tool and following step wise results are obtained.

Table 2.2 : Step 1- Analysis of individual variables

Variable	**P value**	**R^2**
Industrial demand	7.92E-06	0.9507
Annual demand	4.74E-06	0.9573
Peak demand	2.61E-04	0.8674
GDP	2.81E-04	0.8646
Industrial sector GDP	0.5585	0.0511

According to Table 2.1, annual demand and industrial demand got lowest p-values and highest R^2 values. Annual demand is selected for step 2 as it gives the lowest and highest values for p-value and R^2 respectively.

Table 2.3: Step 2-two variable analysis

Second Variable used	**R^2**	**P- values**		**Significance F**
		Annual demand	**Second variable**	
ID	0.9685	0.1150	0.1955	3.12943E-05
Peak demand	0.9603	0.0096	0.5313	6.27331E-05
GDP	0.9779	0.0014	0.0558	1.07434E-05
Industrial sector GDP	0.9656	1.50541E-05	0.2743	4.05894E-05

In the next step, two variable regression analysis results are shown in Table 2.3. Along with other values, significance F values are also calculated. It is observed that none of second variables achieve 95% confidence level test criterion. Although significance F and R^2 is desired, those second variables cannot be accepted. Therefore, final correlation is formed based on step 1 results. Accordingly, annual demand shall define the behaviour of off peak demand given by the following formula.

$$Y = 0.0526 * X + 271.4758$$

Y – annual average of min. off peak demand (MW)
X – annual demand (GWh)

Latest version of CEB generation expansion plan (2015-2034) includes annual electricity demand forecasting up to 2039 with sensitivity. Hence, off peak demand for considered future time period can be forecasted.

As shown in the Table 2.4, stability constraint can be calculated for future years. Prime objective of this forecasting exercise is to derive this limiting factor as it decides when larger capacity units over standard 300 MW could be economically dispatched to the system.

Table 2.4: Off peak demand forecast

Year	Annual Demand (GWh)	Off peak forecast (MW)	Stability constraint (30%)
2016	12015	904.06	271.22
2017	12842	947.60	284.28
2018	13726	994.14	298.24
2019	14671	1043.89	313.17
2020	15681	1097.07	329.12
2021	16465	1138.35	341.50
2022	17288	1181.68	354.50
2023	18155	1227.32	368.20
2024	19069	1275.44	382.63
2025	20033	1326.20	397.86
2026	21050	1379.74	413.92
2027	22125	1436.34	430.90
2028	23243	1495.20	448.56
2029	24402	1556.22	466.87
2030	25598	1619.19	485.76
2031	26827	1683.90	505.17
2032	28087	1750.23	525.07
2033	29395	1819.10	545.73
2034	30759	1890.91	567.27

2. 3.4 Validation of Results

There are several methods to evaluate forecasting accuracy. MAD, MAPE and MSE are such measures, which are often used to evaluate forecasting errors [4].

$$Mean\ Absolute\ Deviation\ (MAD) = \frac{\sum_{t=1}^{N} E_t}{N}$$

$$E_t = (actual\ Demand - demand\ Forecast)$$

$$Mean\ Absolute\ Percentage\ Error(MAPE) = \frac{\sum_{t=1}^{N} \frac{E_t}{Y_t}}{N}$$

$$Y_t - actual\ Demand\ at\ time\ t$$

$$Mean\ Square\ Error\ (MSE) = \frac{\sum_{t=1}^{N} {E_t}^2}{N}$$

N- number of forecasts

Above performance indicators calculated for two forecasts are shown in Table 2.5

Table 2.5 : Evaluation of forecasting results

	Time Series Method	**Multiple regression Analysis**
MAD	28.16	11.64
MAPE	4.31	1.53
MSE	900.80	169.19

According to the results shown in Table 2.5, MAD, MAPE and MSE indicators are lower in regression method. Furthermore, MSE is considerably lower in regression method compared to time series method. It could be deduced that model based on multiple regression analysis method have shown better accuracy in forecasting future off peak demand. Therefore, forecasting results of multiple regression analysis are selected over the other, for further proceedings. Figure 2.3 shows the final annual average minimum off peak demand forecast (base demand) with stability constraint up to 2036.

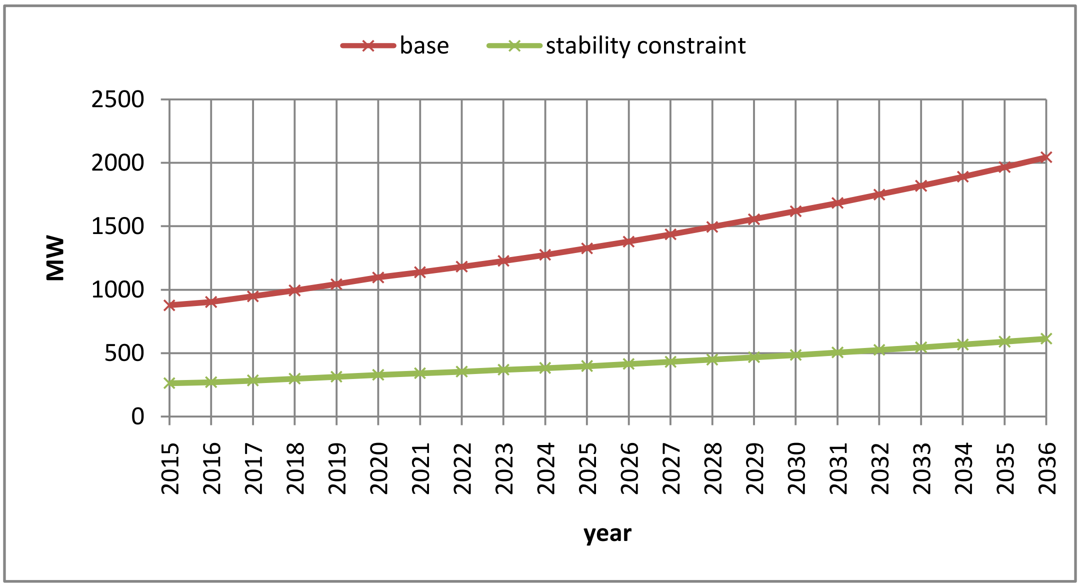

Figure 2.3: Annual off peak demand forecast with stability constraint

2.3.5 Sensitivity Analysis

Base, low, high demand scenarios are considered in sensitivity analysis. Low annual demand forecast was prepared considering base population growth, reduced GDP growth (compared to the base demand forecast) and the increased contribution of the service sector to the total GDP (from 58.5% to 61%). High demand forecast was prepared considering base population growth, high GDP growth and assuming the same GDP sector percentage as of 2013 [1]. Off peak demand sensitivity considering three scenarios is shown in Figure 2.4.

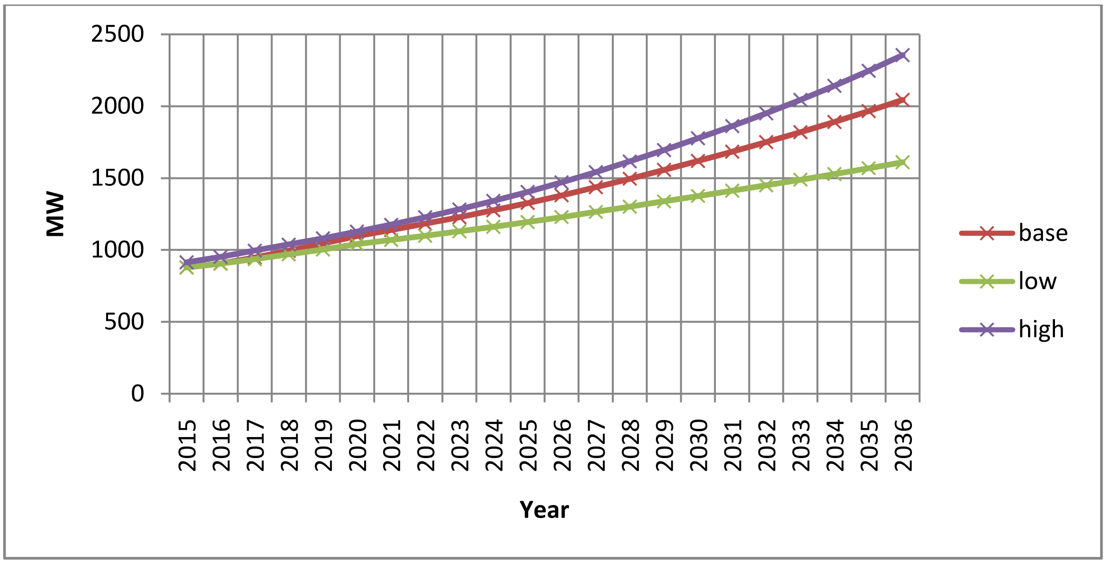

Figure 2.4 : Off peak demand with sensitivity

2.3.6 Comparison with alternative method: Off peak approximation using peak demand forecast

In generation planning studies, future off peak demand is approximated as 40% of peak demand forecast for a particular future year. Figure 2.5 shows the comparison of two methods i.e. approximated off peak demand (using peak demand forecast) with off peak forecast obtained from multiple regression analysis.

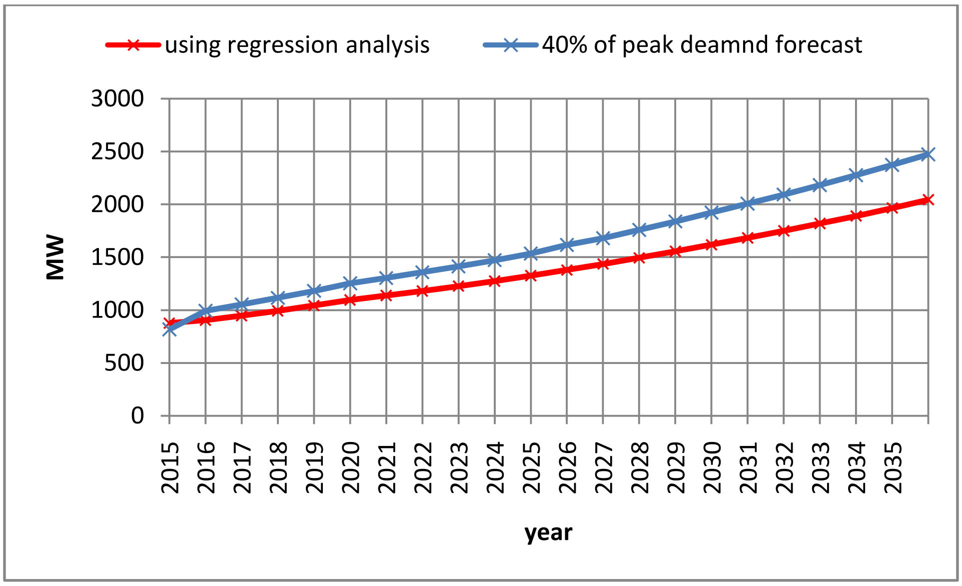

Figure 2.5 : Off peak demand using peak demand Vs regression analysis

Table 2.6: Comparison of results- regression Vs alternative method

	Peak demand based forecast	**Multiple regression Analysis**
MAD	39.85	11.64
MAPE	5.34	1.53
MSE	1979.62	169.19

Eventually, same error indicators calculated to compare peak demand based forecast with regression analysis. According to table 2.6, regression analysis method has shown better accuracy over approximation method (using peak demand). To summarise, results of both time series and regression methods are more accurate compared to approximation based method.

Chapter 3

UNIT CAPACITY AND TECHNOLOGY OPTIONS

Coal power plants have a range of unit sizes. In the past, smaller units were commissioned, but with increasing demand, technology, economy and other factors industry has been moving towards larger unit capacities. As a result of research and development, different technologies were introduced and related research works are in progress for further developments. Technology is a key factor in determination of unit capacity of a coal power plant. Having the main technical constraint discussed in chapter 2, this chapter focuses on different technologies available in the industry and in the latter part feasible unit capacity options are formulated for planned coal plant additions based on those technological options.

3.1 Technological Options

There are several technologies available for coal power generation based on steam boiler design. Summary of those are shown in the Table 3.1.

Table 3.1: Summary of different technologies

Technology	Steam Pressure (MPa)	Main steam/Reheat temp (◦C)	Features	Worldwide availability
Subcritical	≤22.1	≤565/565	Boiler Drum design	74.5%
Adv. Subcritical	≤22.1	540-580/540-580	Once through boiler	
Supercritical	22.1-25	540-580/540-580	Once through boiler	20.5

Ultra-Supercritical	>25	>580	Highest efficiency	1.7
Circulating Fluidizing Bed-Supercritical	≤30	≤600/620	Low grade coal, biomass can be used with Supercritical technology	Few plants

Sources: Performance and risks of adv. Pulverized coal power plants, Nalbandian 2008
World Energy Outlook -IEA
Clean Coal power generation technology review, World bank- 2008

3.1.1 Subcritical Technology

This is the widespread and matured technology used in the industry. The main feature is, it has a boiler drum in which steam is separated. Feed water pressurized by feed water pumps, first enter in to economizer and then to the boiler drum. Feed water entered to the drum is further boiled through natural circulation. i.e. Drum water flow through down comers to the bottom of furnace and then go up through water wall tubes. Fuel combustion is taken place in this area where heat is transferred to water inside wall tubes and then heated water flows to drum again. Figure 3.1 shows a schematic diagram of such boiler.

When water and steam reach the level of absolute pressure 221.2 bar and the corresponding saturation temperature of 374.15^{o}C, the vapor and liquid are indistinguishable and this point is called the 'Critical Point'.

This boiler drum operates below critical point of water (221.2 bar where saturated steam temperature of 374.15^{o}C), where steam separation take place [10]. Moreover, drum water level should maintain in a desired range for smooth supply of steam to turbine. Higher fluctuations are vulnerable to the boiler, in such situations protections are set to trip the boiler. Therefore, fast load changes could make boiler unstable. Typical sub critical steam cycle operating parameters are from 150 to 180 bar pressure and between 540°C and 565°C temperature for superheated steam, with reheat to similar temperatures [11].

In addition, these boilers can be operated using wide range of coal types. Efficiency is comparably lower which consumes larger quantity of coal per unit electricity generated. Consequently, higher fuel consumption leads to higher emissions and other pollutants.

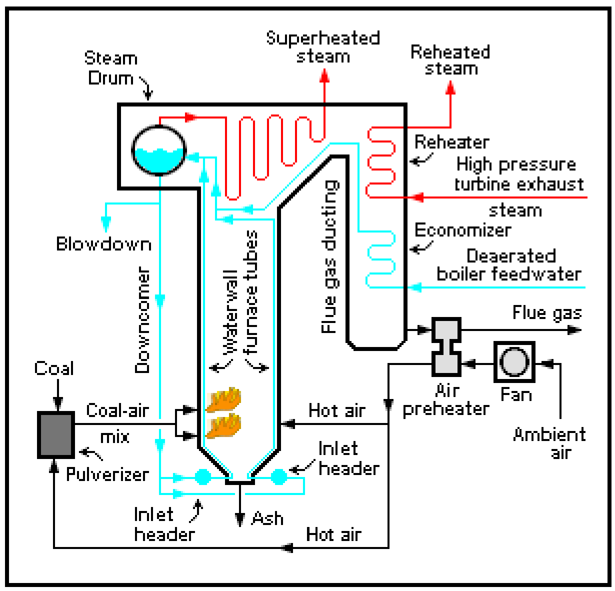

Figure 3.1 : Schematic diagram of subcritical boiler

Source: www.wikipedia.org

3.1.2 Supercritical Technology

Supercritical means thermodynamically there is no distinction between the liquid and gaseous phase. Water/steam reaches this state at about 22.1 MPa (221 bar) pressure [12]. Above this operating pressure of the steam, the cycle is supercritical and its cycle medium is a single phase fluid. As a result there is no need to separate water from steam as in the boiler of a sub critical cycle. Therefore, once -through boilers are used in a supercritical cycle.

Once- through boiler mainly consists of small diameter heat exchangeable tubes through which pressurized water from boiler feed water pump passes through and converted into super heated steam. As the water converts to super heated steam while passing through the tubes, recirculation process and its associated drum is not required. Less reserve water and reduction in thick metal sheets due to elimination of huge drum resulting minimization of stored heat capacity.

3.1.3 Advanced Subcritical Technology

Advanced subcritical (ASUB) plants fall in between subcritical and supercritical technologies. This technology realizes higher turbine thermal efficiency by raising steam temperature only while keeping the steam pressure as a subcritical system. ASUB targets the power units with a capacity of less than or equal to 350MW, where application of super critical system is not feasible due to increased losses in HP turbine. Once through boiler design that has no fixed evaporation point is applied for this type to achieve higher steam temperature.

3.1.4 Ultra Supercritical Technology

The efficiency of a steam cycle is influenced by, the pressure and superheat/ reheat temperatures along with other factors. As these boilers are operating at highest pressure and temperatures compared to previous ones, inevitably their efficiency is higher.

State-of-the art ultra supercritical units operate at even higher steam conditions, between 25 MPa and 29 MPa, and temperatures up to 620°C. With bituminous coal plants incorporating Ultra supercritical technology could achieve efficiencies up to 45% (LHV, net) in temperate locations. Lignite plants can achieve efficiencies close to 44% [13]. LHV stands for Lower Heating Value of fuel excluding the latent heat of vaporization of steam/moisture in combustion process [16]. As steam conditions are increased, both fuel consumption per kilowatt hour (kWh) and specific CO_2 emissions decrease. Advanced Ultra supercritical plants target even higher steam parameters, which are still under development.

3.1.5 Circulation Fluidizing Bed Technology

There are two major categories of fluidised bed combustion units as Bubbling Fluidised Bed Combustion (BFBC) and Circulating Fluidised Bed Combustion (CFBC). Almost all of the recent plant additions have been CFBC units. These units can tolerate a wide variety of coals and particle sizes. High-ash fuels, such as lignite, brown coals and Indian coals are particularly suitable for CFB technology. CFB is considered commercially available up to 300 MW and such units are operating throughout the world. The efficiency of CFBC units is similar to that of PC units [12].

In circulating fluidised bed combustion (CFBC) systems, the fuel is crushed rather than pulverised, and combustion takes place at lower temperatures than in PC systems. Mix of coal and limestone is fed into the combustion. An upward current of combustion air supports a highly mobile bed of ash and fuel. Most of the solids are continuously blown out of the bed before being re-circulated into the combustor. Heat is extracted for steam production from various parts of the system (Figure 3.2). The capacity factor of CFBC power plants is comparable with PC plants. Emissions of NO_X in CFBC systems are intrinsically low because their combustion temperature is relatively low [14].

Meanwhile, most of Circulation fluidizing bed (CFB) plants have subcritical type boilers. Now it is moving towards supercritical technology, where higher capacity units are still in the design stage. The first supercritical CFB unit (460 MW) was located at Lagisza, Poland which is the highest capacity of its category. However with the lower operating temperatures of CFB units, considerable design improvement will be required to achieve higher than 600°C superheat or reheat temperatures [12].

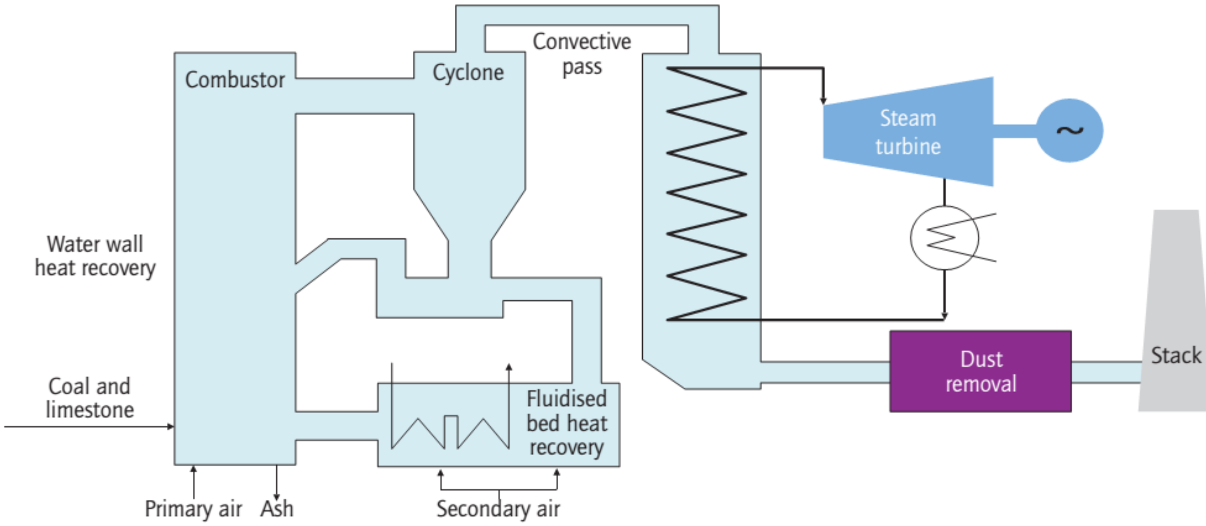

Figure 3.2: Schematic of CFB coal plant

Source: Technology Roadmap, IEA 2012

3.2 Comparisons of Technological Options

3.2.1 Design aspects

Subcritical coal power plants have a boiler drum where saturated steam is separated from liquid phase. In contrast, other types (super critical and Ultra super critical) have once through boilers, as they are operated above critical point of water.

In once through boilers, water flows without circulation in the steam drum, sequentially through the economizer, furnace wall, and evaporating and superheating tubes [10]. These boilers mainly consists of small diameter heat exchangeable tubes through which pressurized feed water passes through and converted into super heated steam. As the water converts to super heated steam while passing through tubes, recirculation process and its associated drum is not required. Similarly, in drum boilers, the constraint to discharge the saturated steam from boiler drum results only saturated steam at super heater inlet. In case of once through boilers, due to non fixation of steam generation point, super heated steam is available at the same point. Therefore steam temperature may be raised to a higher level. However, as steam temperature and pressure increases, material that could withstand such steam conditions is required. This would influence to the cost of the technology.

In case of Drum boilers, the impurities in feed water get concentrated due to precipitation process and finally blow down from boiler drum. In this way, the impurities concentration can be restricted within allowable limits and the purity of steam admitting into steam turbine can be ensured. Nevertheless, as once through boilers do not have drum to carry out precipitation function, impurities in feed water cannot be expelled out and could enter to the turbine along with super heated steam. Therefore, in case of once through boilers, the feed water purity criterion is more stringent than drum boilers.

3.2.2 Operational aspect

Once through boilers are better suited to frequent load variations than drum type boilers, since the drum is a component with a high wall thickness, requiring controlled heating. Moreover, the once through boiler has a lower thermal inertia and thickness of the separating vessel is lower than the drum in a subcritical type boiler. This separating vessel may represent a limitation on the rate of pressure rising in a boiler from a cold condition, but once the unit is on load, these components would not pose any limit to normal load changing. These drum type plants limit the load change rate to 2% per minute, while once through boilers could change the load by 5% per minute. Likewise, higher loading rates are possible in a once though boiler compared to a drum type boiler. This results faster start ups and better load response of supercritical type plant over conventional subcritical plants.

For once through boilers, since there is no reserve energy in the form of steam drum, the control system must match, exactly and continuously, feed water flow and boiler firing rate (both fuel and air) to deliver the desired generator power. The ability of the control system to achieve stable and steady state operation without oscillations is critical to achieve supercritical unit efficiency. Moreover, lower thermal storage capacity of the once through boiler means that the pressure is more sensitive to system abnormalities. Therefore, robust and precise control system is a must for supercritical units.

Additionally, supercritical units consume lesser amount of demineralised water due to absence of boiler drum reservoir. This matters especially at the start ups and shut downs, when drum filling requires considerable amount of water. Accordingly, the cost of water and chemical treatment is less compared to subcritical technology. However, feed water quality should be maintained strictly within the specified range as mentioned earlier.

3.2.3 Fuel flexibility

There are mainly three classifications of coal namely; Anthracite, Bituminous and Lignite. Lignite (brown coal) has the lowest grade of coal whereas anthracite is the highest one. Basically, carbon percentage and heat content increase with the grade. For the purpose of electricity generation, Bituminous and Lignite coal are used. Subcritical power plants have been successfully operating with all these varieties of coal. However, fuel flexibility is not compromised in supercritical plants also. All the various types of firing systems used to fire a wide variety of fuels have already been implemented for once through boilers [10].

Fuel diversity is highest in circulation fluidizing bed combustion (CFBC) units as they could tolerate a wide variety of coals and particle sizes, because of their low operating temperatures and staged combustion. They have the ability to accept a variety of fuels, including a range of coal from Lignite to anthracite, waste coal and biomass [14].

3.2.4 Heat rate and Emissions

Advantage of supercritical technology is that it offers higher efficiencies than subcritical technology. Main motive for a supercritical unit is to increase the overall plant thermal efficiency thereby reducing the fuel consumption per unit of electricity generated. It also results in lower particulate and gaseous pollutant emissions per unit of electricity generated in addition to lower fuel consumption. This could be achieved either by increasing superheated/re-heated steam temperatures/pressure or both. Typical efficiencies are shown in Table 3.3.

Emissions of NO_X in CFBC systems are inherently low because the combustion temperature is relatively low. The lower operating temperature is also ideally suitable for capture of sulphur dioxide. Limestone is fed into the combustion system to control SO_2 emissions, typically achieving 95% reduction [14]. Although typical efficiency is similar to the subcritical technology, newer supercritical CFB boilers are operating in higher efficiencies.

Summarized pros and cons of each technology are shown in Table 3.2.

Table 3.2 : Comparison of different technologies

Technology	**Advantages**	**Disadvantages**
Subcritical	- Wide spread matured Technology - Rich experience with wide range of coal	- Comparably lower efficiency - Higher emissions - small and medium size units
Adv. Subcritical	- Higher efficiency, lower emissions compared to sub-critical boilers - Once through boiler design	- Not suitable for large unit capacities - Low availability of operational units
Supercritical	- Reduction of fuel costs -Reduction of CO_2 and other emissions - Better part load efficiency - Better load response - Fast start ups - Less water consumption for boiler	- Higher capital cost - Larger minimum unit size - Material development for Supercritical conditions - Need precise and robust control equipment
Ultra-Supercritical		
Circulation Fluidizing Bed	- Fuel flexibility - High ash /moisture, low quality coal can be fired, biomass co-firing - Low operation temperatures & less NOx - Desulfurization in boiler	- Small sized units - Low availability (Supercritical type plants) - High waste products

3.2.5 Cost Comparison

Table 3.3 : Financial aspects of technological options

Technology	**Efficiency (%HHV net)**	**Cost (US$/kW) OECD countries**	**O &M cost**		**Typical unit Capacity range (MW)**
			Variable ($/kW-yr)	**Fixed ($/MWh)**	
Subcritical	35- 38%	1347	40.5	1.7	Up to 500
Supercritical	38- 40%	1431	40.8	1.65	500~1100
Ultra-Supercritical	40- 42.5%	1529	41.1	1.6	600~1300
Circulation Fluidizing Bed	35- 38% (40%*)	1153	42.2	3.4	Up to 300 (460MW*)

*- refer to Supercritical CFB units

Sources:

1. Coal power generation technology review-background paper, word bank 2008
2. Performance and risks of adv. Pulverized coal power plants, Nalbandian 2008
3. Power generation from coal, IEA 2011 Oct

According to Table 3.3, it is evident that capital cost per unit capacity tends to increase when technology advances. Thus supercritical plant capital costs are typically up to 6 percent higher than similar size subcritical plants. Ultra supercritical plants are 5~10 percent more expensive than subcritical plants. The higher capital costs of supercritical technology are mainly due to the advanced alloys used and the welding techniques required, for operation at higher steam pressures and temperatures [14]. However above plant capital costs figures differ based on the manufacturer and region. (For instance China and India have been recorded comparably lower prices). But, O & M costs are similar for all types of pulverized coal plants.

The capital costs of CFB plants are affected by many site specific factors, such as coal properties, environmental regulations, sourcing of the key components and geophysical characteristics of the construction site. Although, average CFB plant capital cost shown in the Table 3.3 is lower than subcritical plant, it is estimated that CFB costs are comparable with pulverized coal plants with FGD units [15].

3.3 Unit Capacity Options

Typical unit capacities available for respective technologies are shown in Table 3.3. Accordingly low and medium size units fall in to subcritical, circulation fluidizing bed (CFB) and advanced subcritical technologies. Supercritical and ultra super critical technologies are available for larger units sized typically over 500 MW.

In case of super critical units, the volume flow inside the turbine is reduced which results in short HP turbine blades length. As unit capacity is reduced, shorter HP turbine blades length results in larger steam energy loss due to increased leakage flow through relatively large gaps between HP turbine blades and casing. In that case, merit of cycle efficiency rise caused by high temperature and pressure is cancelled out. Therefore, supercritical technology is only used for larger unit capacities.

Most of the CFB plant capacities are limited to 300MW and available few supercritical plant are in the range of 300~460 MW [12].

3.3.1 Feasible Options for Unit Capacities

In long term generation expansion plan 2015-2034, the lowest cost generation additions are presented in order to meet future demand satisfying other constraints. Accordingly, proposed coal power unit additions are shown in Table 3.4. It can be seen that apart from 250 MW units, all others are 300 MW in capacity wise. Therefore, without affecting the given schedule, other feasible unit technology/capacity options are proposed and shown in Table 3.4. Stability constraint represents maximum allowable unit capacity that could be dispatched at off peak, without violating system stability criterion.

Table 3.4 : Summary of feasible unit capacity/technology options

Year	Stability constraint (MW)	Future Coal power plant additions (MW)		Technology Options
		Proposed	As per the LTGEP 2015-2034	
2020	329	Committed plant	250 (X2)	-
2022	355	Not considered due to long de-rating period	300 (X2)	
2024	383	-	300	
2027	431	-	300	
2029	467	**600 (6 years de-rate)**	300	Supercritical
2030	486		300	
2032	525	**600 (4 years de-rate)**	300 (X 2)	

Main objective is to determine the best option available (in technology and capacity wise) for each future coal power unit additions, considering stability constraint for different unit capacities. In general once unit capacity increases, more efficient technologies could be employed provided that incremental cost is recovered.

Firstly, 2 X 250 MW unit additions are committed plants in Sampur, where unit capacity and technology are fixed. In 2022, 2 X 300 MW units will be added, to which 600 MW single high efficient unit could be proposed. In that case, 600 MW unit have to operate at part load for considerable future period of time (during off peak hours), as stability limit is low. It makes this option not favourable for further analysis. It is worthwhile to note that stability constraint reach 600 MW mark by year 2036.

Moreover in 2024 and 2027, two 300 MW individual units are scheduled to be added. According to LTGEP, those are ASUB units which have higher efficiency over CFB and subcritical plants in medium capacity range. Therefore, those additions are not considered further.

In 2029-2030, instead of 2X 300 MW units, single 600MW high efficient Supercritical unit is proposed with partial load operation until 2036. Likewise, in 2032 also 600 MW unit is proposed with partial load operation of 4 years.

Eventually, sub optimization of unit capacities are formulated based on the prior analysis of different coal power generation technologies. Next step is to find out the best option in each scenario, evaluating associated cost and benefits.

Chapter 4

FINANCIAL ANALYSIS

This chapter focuses on evaluation of financial aspect of proposed options in previous chapter. Basically, project costs are compared with associated benefits where net gain or loss can be derived. As the project life time is longer, appropriate assumptions are made wherever needed in order to compare the available options using project appraisal techniques.

4.1 Scenarios for Financial Analysis

Table 4.1 : Options for financial analysis

Case	Year	Plant addition according to LTGEP	Proposed option
A	2029/2030	2X 300 MW	600 MW Supercritical (with 6 years partial load operation)
B	2032	2X 300 MW	600 MW Supercritical (with 4 years partial load operation)

As shown in the Table 4.1, two cases were identified for financial analysis based on screening analysis in chapter 4. Accordingly, proposed high efficient supercritical units are compared against advanced sub critical units with once through boilers, which are more efficient than conventional subcritical plants.

Moving to higher unit capacity enables the use of high efficient supercritical and ultra supercritical technologies. In financial perspective, advantage of "economy of scale" also have an impact on cost figures. However, higher capital cost is the main concern associated with cost of capital. In order to validate the option, incremental capital cost should be recovered by fuel savings due to efficiency gain. Additionally due to stability constraint, higher capacity unit required to run at partial loads during off peak for several years at the beginning which will compromise its efficiency gain.

4.2 Project Appraisal Techniques used

Financial validation is critical for any type of future project, which requires to be done in early stages. Different methods are available to evaluate financial viability of individual project or compare two project options. Usually different techniques applied together as it will provide better picture about the projects considered. Accordingly, following techniques are commonly used to evaluate financial performance in power plant economics [18].

4.2.1 Levelised Cost of Electricity (LCOE)

The levelised cost of electricity (LCOE) is the net present value of the unit cost of electricity over the lifetime of a generating plant. It is a first order economic assessment of the cost competitiveness of electricity generating system that includes all costs over its lifetime such as initial investment, cost of capital, fuel cost, operations and maintenance etc. This can be roughly calculated as the net present value of all costs over the lifetime of the asset divided by the total electrical energy output of the asset [2]. This is often used to compare economy of different generation options.

$$\text{levelized cost of electricity (LCOE)} = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ electrical\ energy\ produced\ over\ lifetime}$$

$$= \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where,

I - Investment cost

M - O & M cost

F - fuel cost

E- electrical energy generation per annum

r – discount rate

n – lifetime in years

4.2.2 Discounted Cash flow Analysis

Cash flow describes as real or virtual movement of money. Cash outflows like investments, costs are negative cash flows where all types of income categorized as positive cash flows. Difference of two indicates the net cash flow for the period. Discounted cash flow (DCF) analysis is a method of valuing a project or asset using the concepts of the time value of money. After the cash flow of each period is calculated, the present value (PV) of each one is achieved by discounting its future value to present value using discounting factor.

$$Present\ Value = \frac{Future\ \ Value}{(1+r)^n}$$

r - discount rate

n –no. of years

4.2.3 Net Present Value (NPV)

Net present value is a central tool in discounted cash flow analysis and is a standard method for using the time value of money to appraise long-term projects. NPV is the sum of all the discounted future cash flows. Therefore, NPV is a useful tool to determine whether a project or investment will generate a net profit or a loss. A positive NPV results in profit, while a negative NPV results in a loss.

$$NPV(i,N) = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$$

R_t - net cash flow

i - discount rate

t – time of cash flow

N- total number of periods

4.2.4 Internal Rate of Return (IRR)

Internal rate of return of project is the rate of return that makes the net present value of all cash flows from a particular investment equal to zero. It can also be defined as the discount rate at which the present value of all future cash flow is equal to the initial investment or else, the rate at which an investment breaks even [2].

Equivalently, the IRR of an investment is the discount rate at which the present value of costs of the investment equals the present value of the benefits of the investment resulting to a zero net present value. IRR calculations are commonly used to evaluate the desirability of investments or projects. Project is acceptable if its IRR is greater than minimum acceptable rate of return or cost of capital which project breaks even. When several investment options are available, investment with higher IRR is always desirable as it yields higher profits.

4.3 Assumptions and Data used

Following assumptions are made in order to carry out financial analysis.

4.3.1 Plant related assumptions

- Availability factor is 80%
- Plant life time is 30 years
- System stability constraint remains at 30%
- Equal size coal units (e.g. 300 MW) are equally dispatched
- Plant heat rate is linearly correlated to megawatt output of coal plants
- Pump storage plant efficiency is 80% [21].
- Off peak period is 0000 hr to 0400 hr (assumed that during off peak period, demand is constant)

4.3.2 Assumptions for Financial Analysis

- Discount rate is 10%
- Debt to equity ratio is 80:20
- Loan interest rate (in USD) is 6%

- Exchange rate- Rs 150/ USD
- Loan period is 10 years
- Rate of equity payment is 13%
- Initial capital investment cost per megawatt (USD/MW) is unchanged for two cases
- Carbon tax rate - USD 20 per tonne of CO_2 [20]
- Unit selling price

  For this analysis, unit selling price is assumed as Rs 16/ kWh based on average rates as it is difficult to predict the unit price variation over plant lifetime [17].

- Constant cost basis

  According to above Table 4.1, intended time period for the analysis is 2030-2062 as plant life time is assumed to be 30 years. This involves long term forecasting of fuel prices, average tariff rates, O&M costs in order to do cash flow analysis. However, it is very difficult to predict those figures accurately for such long future time period. In addition, these figures are highly sensitive to final results of the analysis. Hence, this financial analysis is carried out in constant cost basis. It should be noted that, prime objective is to compare the two options in each case and determine the best option. As same data inputs are used for both and plant life spans are closer to each other, this approach will not affect to the final outcomes of the analysis. Furthermore, sensitivity analysis is carried out to evaluate how critical parameters affect to final outcomes.

4.3.3 Other data used

Coal and plant data extracted from LTGEP [1].

- Coal data

Calorific Value (kcal/kg)	Cost ($/MT)
6300	124.1

Table 4.2 : Plant data for financial analysis

	Unit	Advanced subcritical	Supercritical
Installed capacity	MW	300	600
Net output	MW	270	564
Scheduled Annual maintenance duration	days	45	45
Minimum operating level	%	35	60
Heat rate at full load	kcal/kWh	2241	2082
Heat rate at minimum operating level	kcal/kWh	2810	2248
Capital cost	US$/kW	2119.4	2269.7
Annual fixed O&M cost	US$/kW-month	4.47	4.5
Variable O&M cost	UScts/kWh	0.59	0.59
Life time	years	30	30

4.4 Methodology

Discounted cash flow analysis is carried out using MS Excel software. Off peak Demand forecast data extracted from Table 2.4 are used to identify the plant dispatch schedule of proposed options. Respective cash flow statements can be referred in annexure A -E together with loan schedules.

In each case, annual cash flow statements are prepared for both options considered. Throughout plant life time, each year's annual costs and income figures are calculated. Costs can be sub categorized in to fuel cost, operations and maintenance cost as well as financial costs.

Annual Operation and maintenance cost comprises of fixed and variable components. Fixed component is based on capacity while variable component depends on annual energy output. In addition, financial costs comprises of annual interest payment, loan payment and equity payment. Loan interest is calculated on annual average balance and debt payments are equally distributed over loan period. (refer annexure G-H) Equity payment is payable for equity capital component of initial investment.

Annual total cash flow is the difference between operating cost (i.e. fuel and O&M costs) and income figures. Net cash flow is calculated by further deduction of financial costs. In order to calculate Present value of a cash flow, net cash flow is multiplied by respective discounting factors. Accordingly Net present value, IRR and LCOE are calculated.

4.5 Results of the Study

4.5.1 Base Scenario

Final results of the financial analysis of case A & case B, 600 MW supercritical plant Vs 2X300 MW advanced subcritical units are shown in Table 4.3 & Table 4.4 respectively (refer annexure A-C). It should be noted that figures are same in two cases of 300MW option, due to constant cost basis used.

Table 4.3 : Results of financial analysis – case A (2030)

	600 MW supercritical unit	**2X300 MW units**
IRR	10.5 %	8.54 %
NPV (US$)	32,292,946	-88,001,716
LCOE (UScts/kWh)	8.82	9.26

Table 4.4 : Results of financial analysis – case B (2032)

	600 MW supercritical unit	**2X300 MW units**
IRR	10.75%	8.54%
NPV (US$)	48,012,073	-88,001,716
LCOE (UScts/kWh)	8.78	9.26

As seen from the results, both plants 600MW supercritical plants have positive NPVs and higher IRR figures over 300 MW units. Accordingly, LOCE of 600MW plant is lower than 300 MW option which is more economical.

Part load operation results higher heat rate during off peak hours, and hence gain on fuel savings will be reduced. It should be noted that, in Case A 600 MW plant is operating on part load for 6 years while in case B, respective time period is reduced to 4 years. Therefore, more fuel saving is expected in case B supercritical plant.

Additionally, same results can be observed for 2X300 MW units in both cases. As constant cost basis is assumed and plant operating characteristics are similar, cost figures are same in both cases. Since this analysis focus on comparing given options in each case and projects schedules lies in nearby years, results are justifiable.

To summarize, single 600 MW high efficient supercritical plants are more profitable compared to 300 MW units due to gain in fuel savings.

4.5.2 Carbon Taxation Scenario

On the environmental perspective, supercritical plant consumes less coal quantity to produce equivalent energy than advanced subcritical units. It will result lesser CO_2 emissions, accompanied with monetary value in terms of GHG emission reduction. Likewise, carbon taxation can be incorporated to supercritical plant in base scenario and following results are obtained. (refer annexure D-E)

Table 4.5: Case A - 600 MW supercritical unit with carbon taxation

	Without carbon taxation	**With carbon taxation**
IRR	10.5 %	11.12 %
NPV (US$)	32,292,946	72,275,363

Table 4.6: Case B- 600 MW supercritical unit with carbon taxation

	Without carbon taxation	With carbon taxation
IRR	10.75%	11.41 %
NPV (US$)	48,012,073	89,133,847

According to Table 4.5 and Table 4.6, in both cases IRR values have been increased for supercritical plants compared to base scenario.

4.5.3 Scenario with Pump Storage Plant addition

According to LTGEP 2015-2034, total capacity of 600 MW pump storage plants are proposed to improve the efficiency of coal power plants and for better absorption of renewable energy. In that case, 200 MW and 2X 300 MW pump storage plants will be added to the system in 2025 and 2026 respectively. This will increase the off peak demand and stability constraint (refer annexure F, I), which enables to operate both 600 MW supercritical plants at rated capacity throughout the day.

Table 4.7: Base scenarios Vs pump storage plant scenario

	Base scenarios		With pump storage plants (600 MW)
	Case A	Case B	
IRR	10.5 %	10.75%	10.96%
NPV (US$)	32,292,946	48,012,073	60,291,134
LCOE (UScts/kWh)	8.82	8.78	8.76

Accordingly with pump storage capacity addition, in both cases efficiency loss due to partial load operation could be eliminated. Therefore, IRR will be increased and unit cost will be reduced as shown in the Table 4.7.

4.6 Sensitivity Analysis

Sensitivity can be analysed against different parameters to check validity of above results under different conditions. Likewise variation of IRR and LCOE could be traced under favourable and adverse conditions. Similarly, fuel price and selling cost are subjected to sensitivity analysis as follows. According to above results, Case A is selected for the sensitivity analysis as case B option has shown comparably better performance.

4.6.1 Sensitivity with Fuel price

Table 4.8 : Coal price sensitivity – case A

		600 MW	**2X 300 MW**
Coal price increased by 20%	IRR	6.27%	3.61%
	LCOE(UScts/kWh)	9.69	10.24
Coal price reduced by 20%	IRR	15.2%	13.93%
	LCOE(UScts/kWh)	7.94	8.28

Sensitivity is analysed with 20% price variation from estimated future fuel cost. Reduction of coal price obviously improves the financial indices and vice versa. However in both scenarios, Competitive advantage of supercritical unit doesn't change.

4.6.2 Sensitivity with Unit Selling price

Table 4.9 : Sensitivity with unit selling price – case A

IRR	**600 MW**	**2X 300 MW**
Unit selling price increased to LKR 17/kWh	14.10%	12.11%
Unit selling price reduced to LKR 15/kWh	7.25%	5.18%

According to Table 4.6, variation of unit selling price by LKR 1/kWh will have a considerable impact on rate of return. Therefore, results show high sensitivity on selling price. Although in all cases, 600 MW plant shows better results over the other option.

Chapter 5

CONCLUSION AND RECOMMENDATIONS

According to LTGEP 2015-2034, number of coal power plants are proposed to be added to the grid to satisfy increasing future demand. In this study, stability constraint is forecasted using average minimum off peak demand. As multiple regression analysis method provides more accurate results, it is used for off peak demand forecasting and for estimation of stability constraint. It is observed that minimum off peak demand is growing at 5.7% annually for the time period 2016-2034.

Subsequently, different available coal plant unit capacity options are analysed along with their technologies and feasible options are formulated in accordance with LTGEP. After preliminary screening studies in chapter 3, 600 MW high efficient supercritical plants are substituted for 2X 300MW new coal power plants and financial evaluation is carried out in chapter 4. As per the obtained results, it is concluded that 600 MW high efficient supercritical plant is financially viable, which have better performance (in terms of IRR, NPV and LCOE) compared to 2X 300MW new coal power plants. Two other scenarios are also considered with proposed pump storage plant addition and carbon taxation. In both scenarios, profitability will be increased compared to the base scenario.

In addition to financial aspects, there are other advantages with regard to reduction of emissions and ash products. According to cash flow analysis, approximately annual coal saving of 93,038 MT is expected from high efficient supercritical plant over the proposed 300 MW option in LTGEP. As a result, there is a considerable reduction of ash products (fly ash, bottom ash), which amounts to 10- 15% of coal [19]. Furthermore, it is important to analyse the economical and environmental benefits by reduction of other major hazardous emissions like CO_2, SO_x and particulate matter over its long life time in addition to carbon taxation. Accordingly, supercritical technology will be a feasible and economical option for future power generation, while minimizing present negative externalities to the environment.

Ultimately, it is concluded that high efficiency supercritical units can perform better in financial as well as in other aspects without violating system constraints. Therefore, it is recommended to proceed with high efficiency supercritical option instead of proposed 300 MW units in 2030 and 2032. In future generation planning, in detail studies are required to be carried out including feasibility studies for addition of high efficiency supercritical power plants covering technical, economical, financial and environmental aspects. This attempt can be used as a basis for such in detailed technical study. Furthermore, this methodology can be customized for other technologies such as selection of LNG plants which is the newest power generation source proposed as a substitution for coal plants.

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Appendix – A: Cash flow analysis for case –A, 600 MW SC unit (2030-2059) [all cash flows in US$]

Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036-2059**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209	0.5645	0.5132
Off peak demand(MW)	485.76	505.17	525.07	545.73	567.27	589.78	600.00
Off peak Heat rate (kcal/kWh)	2157.85	2144.57	2131.13	2117.36	2103.18	2088.57	2082.00
Fuel MT	1170321.47	1180821.36	1190573.51	1199623.44	1207907.79	1215318.70	1218267.43
Total fuel cost	145236894.09	146539931.37	147750172.01	148873268.77	149901356.67	150821050.15	151186987.89
O &M cost	51826018.29	52045462.20	52250746.00	52442755.59	52620097.23	52780410.63	52844774.40
Fuel and O & M cost	197062912.38	198585393.56	200000918.01	201316024.35	202521453.90	203601460.78	204031762.29
Energy (MWh)	3292545.47	3329739.36	3364533.22	3397077.22	3427135.12	3454306.89	3465216.00
Energy sales	351204850.39	355172197.90	358883543.44	362354903.29	365561079.85	368459401.28	369623040.00
Net cash flow(sales - costs)	154141938.01	156586804.34	158882625.43	161038878.94	163039625.96	164857940.50	165591277.71

Appendix – B: Cash flow analysis for case –B, 600 MW SC unit (2032-2061) [all cash flows in US$]

Year	**2032**	**2033**	**2034**	**2035**	**2036-2061**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209
Off peak demand (MW)	525.07	545.73	567.27	589.78	600.00
Off peak Heat rate (kcal/kWh)	2131.13	2117.36	2103.18	2088.57	2082.00
Fuel MT	1190573.51	1199623.44	1207907.79	1215318.70	1218267.43
Fuel rate ($/MT)	124.10	124.10	124.10	124.10	124.10
Total fuel cost	147750172.01	148873268.77	149901356.67	150821050.15	151186987.89
O &M cost	52250746.00	52442755.59	52620097.23	52780410.63	52844774.40
Fuel and O & M cost	200000918.01	201316024.35	202521453.90	203601460.78	204031762.29
Energy (MWh)	3364533.22	3397077.22	3427135.12	3454306.89	3465216.00
Energy sales	358883543.44	362354903.29	365561079.85	368459401.28	369623040.00
Net cash flow(sales - costs)	158882625.43	161038878.94	163039625.96	164857940.50	165591277.71

Appendix – C*:* Cash flow analysis for case –A, 2X 300 MW units (2030-2059) [all cash flows in US$]

Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036-2059**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209	0.5645	0.5132
Off peak demand(MW)	485.76	505.17	525.07	545.73	567.27	589.78	600.00
Plant Heat rate (kcal/kWh)	2241.00	2241.00	2241.00	2241.00	2241.00	2241.00	2241.00
Fuel MT	1311305.14	1311305.14	1311305.14	1311305.14	1311305.14	1311305.14	1311305.14
Total fuel cost	162732968.23	162732968.23	162732968.23	162732968.23	162732968.23	162732968.23	162732968.23
O &M cost	51758784.00	51758784.00	51758784.00	51758784.00	51758784.00	51758784.00	51758784.00
Fuel and O & M cost	214491752.23	214491752.23	214491752.23	214491752.23	214491752.23	214491752.23	214491752.23
Energy (MWh)	3317760.00	3317760.00	3317760.00	3317760.00	3317760.00	3317760.00	3317760.00
Energy sales	353894400.00	353894400.00	353894400.00	353894400.00	353894400.00	353894400.00	353894400.00
Net cash flow(sales - costs)	139402647.77	139402647.77	139402647.77	139402647.77	139402647.77	139402647.77	139402647.77

Appendix – D*:* Cash flow analysis for case –A with carbon taxation [all cash flows in US$]

Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036-2059**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209	0.5645	0.5132
Off peak demand(MW)	485.76	505.17	525.07	545.73	567.27	589.78	600.00
Off peak Heat rate (kcal/kWh)	2157.85	2144.57	2131.13	2117.36	2103.18	2088.57	2082.00
Fuel MT	1170321.47	1180821.36	1190573.51	1199623.44	1207907.79	1215318.70	1218267.43
Total fuel cost	145236894.09	146539931.37	147750172.01	148873268.77	149901356.67	150821050.15	151186987.89
O &M cost	51826018.29	52045462.20	52250746.00	52442755.59	52620097.23	52780410.63	52844774.40
Fuel and O & M cost	197062912.38	198585393.56	200000918.01	201316024.35	202521453.90	203601460.78	204031762.29
Energy (MWh)	3292545.47	3329739.36	3364533.22	3397077.22	3427135.12	3454306.89	3465216.00
Energy sales	351204850.39	355172197.90	358883543.44	362354903.29	365561079.85	368459401.28	369623040.00
Net cash flow(sales - costs)	154141938.01	156586804.34	158882625.43	161038878.94	163039625.96	164857940.50	165591277.71
Carbon taxation income	3605591.94	3775999.86	3938759.34	4094407.63	4241704.56	4378575.46	4434797.71

Appendix – E*:* Cash flow analysis for case –B with carbon taxation [all cash flows in US$]

Year	**2032**	**2033**	**2034**	**2035**	**2036-2061**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209
Off peak demand (MW)	525.07	545.73	567.27	589.78	600.00
Off peak Heat rate (kcal/kWh)	2131.13	2117.36	2103.18	2088.57	2082.00
Fuel MT	1190573.51	1199623.44	1207907.79	1215318.70	1218267.43
Fuel rate ($/MT)	124.10	124.10	124.10	124.10	124.10
Total fuel cost	147750172.01	148873268.77	149901356.67	150821050.15	151186987.89
O &M cost	52250746.00	52442755.59	52620097.23	52780410.63	52844774.40
Fuel and O & M cost	200000918.01	201316024.35	202521453.90	203601460.78	204031762.29
Energy (MWh)	3364533.22	3397077.22	3427135.12	3454306.89	3465216.00
Energy sales	358883543.44	362354903.29	365561079.85	368459401.28	369623040.00
Net cash flow(sales - costs)	158882625.43	161038878.94	163039625.96	164857940.50	165591277.71
Carbon taxation income	3938759.34	4094407.63	4241704.56	4378575.46	4434797.71

Appendix- F: Cash flow analysis with pump storage plant addition [all cash flows in US$]

Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036-2059**
DCF	0.9091	0.8264	0.7513	0.6830	0.6209	0.5645	0.5132
Off peak demand (MW)	600	600	600	600	600	600	600.00
Off peak Heat rate (kcal/kWh)	2082.00	2082.00	2082.00	2082.00	2082.00	2082.00	2082.00
Fuel MT	1,218,267.43	1,218,267.43	1,218,267.43	1,218,267.43	1,218,267.43	1,218,267.43	1,218,267.43
Total fuel cost	151,186,987.89	151,186,987.89	151,186,987.89	151,186,987.89	151,186,987.89	151,186,987.89	151,186,987.89
O &M cost	52844774.40	52844774.40	52844774.40	52844774.40	52844774.40	52844774.40	52844774.40
Fuel and O & M cost	204031762.29	204031762.29	204031762.29	204031762.29	204031762.29	204031762.29	204031762.29
Energy (MWh)	3465216	3465216	3465216	3465216	3465216	3465216	3465216
Energy sales	369623040	369623040	369623040	369623040	369623040	369623040	369623040
Net cash flow(sales - costs)	165591277.71	165591277.71	165591277.71	165591277.71	165591277.71	165591277.71	165591277.71

Appendix – G*:* Loan schedule for case –A, 600 MW Supercritical unit [all cash flows in US$]

Total Investment cost	1361820000
Debt (80%)	1089456000
Equity (20%)	272364000
Interest rate	6%

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
loan opening balance	1089456000	980510400	871564800	762619200	653673600	544728000	435782400	326836800	217891200	108945600
annual loan payment	108945600	108945600	108945600	108945600	108945600	108945600	108945600	108945600	108945600	108945600
Interest	62098992	55562256	49025520	42488784	35952048	29415312	22878576	16341840	9805104	3268368
loan closing balance	980510400	871564800	762619200	653673600	544728000	435782400	326836800	217891200	108945600	0
ROE	35407320	35407320	35407320	35407320	35407320	35407320	35407320	35407320	35407320	35407320

Appendix – H*:* Loan schedule for case –A, 2X 300 MW units [all cash flows in US$]

Total Investment cost	1271640000
Debt (80%)	1017312000
Equity (20%)	254328000
Interest rate	6%

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
loan opening balance	1017312000	915580800	813849600	712118400	610387200	508656000	406924800	305193600	203462400	101731200
annual loan payment	101731200	101731200	101731200	101731200	101731200	101731200	101731200	101731200	101731200	101731200
Interest	57986784	51882912	45779040	39675168	33571296	27467424	21363552	15259680	9155808	3051936
loan closing balance	915580800	813849600	712118400	610387200	508656000	406924800	305193600	203462400	101731200	0
ROE	33062640	33062640	33062640	33062640	33062640	33062640	33062640	33062640	33062640	33062640

Appendix – I*:* Adjusted stability constraint forecast considering addition of pump storage power plants

Year	Off peak forecast (MW)	Stability constraint (30%)
2016	904.06	271.22
2017	947.60	284.28
2018	994.14	298.24
2019	1043.89	313.17
2020	1097.07	329.12
2021	1138.35	341.50
2022	1181.68	354.50
2023	1227.32	368.20
2024	1275.44	382.63
2025	1526.2	457.86
2026	1979.74	593.92
2027	2036.34	610.90
2028	2095.20	448.56
2029	2156.22	628.56
2030	2219.19	665.76
2031	2283.90	685.17
2032	2350.23	705.07
2033	2419.10	725.73
2034	2490.91	747.27