CHAPTER VI
A CASE STUDY OF COGENERATION POTENTIAL IN THE
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6.1 INTRODUCTION

The sugar industry has been identified as the cheapest source of cogenerated power in the study conducted by M/s Hagler and Bailly (1986). The study estimated the potential for extra power generation in the sugar industry of Gujarat and Maharashtra as 425 MW. It may be visualised by extrapolating the above figure to the 396 operating sugar plants all over the country, that the industry as a whole has a massive potential for cogeneration. Sugarcane wastes, namely, bagasse and also others like fibre residue, crushed sugar and leftovers at the field can be used as the fuel for raising steam in the boiler house. This in turn can run the power turbines and the passout goes for process-use. The cane-crushing season is November to April, which coincides with the season of peak agricultural demand for electricity and minimum hydel power supply. Moreover, the same infrastructure can be used during off-season (May to October) with alternative conventional fuels to contribute to the country’s peak summer load. Thus, cogeneration offers an attractive option for contributing to meet the deficit in utility power generation.

In this chapter an attempt has been made to estimate the cogeneration potential of a typical sugar plant, based on the details of operations of the Daurala Sugar Works, Uttar Pradesh, India. A historical perspective of the performance of the sugar industry is presented in the preliminary section. Subsequently, a description of the sugar manufacturing process and special features of the same which are relevant to cogeneration, are given. Operational details of the plant under study with special
emphasis on the steam and energy flow are provided next. The steam and energy relations thus obtained have been used to form the constraints of a linear optimisation problem to estimate the surplus potential for bagasse-based cogeneration of power by maximisation of power output. Another optimisation problem has been solved for the minimisation of fuel cost under the same constraints to meet the in-plant power demand only. The results of the optimisation exercises have been used to compute the per unit price at which the cogenerated power can be supplied. These computations have been carried out for alternative machine configurations for both the in-season and off-season periods. Furthermore, an optimal mix of bagasse and purchased fuel, if any, is obtained for each model option for cogeneration of power in the sugar plant. The entire exercise has been aimed to find out the amount of exportable surplus power in the sugar industry and whether its supply price is attractive for both the utility and the cogenerator. While a price lower than the utility's own cost of generation makes it beneficial for the utility to buy, an additional profit over cost justifies the cogenerator's rationale to venture into such projects.

6.2 A REVIEW OF THE GENERIC INDUSTRY

6.2.1 Current Status of the Sugar Industry*

India is reputed to be the mother country of sugarcane and leads the world by producing approximately 180 million tonnes per annum. The sugar industry is India's second largest agro-based industry, next to cotton textiles, producing the largest amount of sugar of the world. At the initial phase of development of the industry in 1930-31,

* All figures in this section are based on the reports of the National Federation for Cooperative Sugar Factories (NFCSF) and various issues of their monthly bulletin, Cooperative Sugar.
the number of factories was 29, producing merely 1.2 lakh tonnes of sugar annually. This increased to 9.34 lakh tonnes in 135 factories by 1935-36. Subsequently, there was hardly any development in the industry till independence. The next phase of development came up during the planning period raising the production of crystal sugar to 109.89 lakh tonnes per annum in 1989-90. Due to the introduction of improved variety of seeds, irrigation, manure, etc., the yield of sugarcane has increased from 30.9 tonnes per hectare to 65.4 tonnes per hectare on an average in the period 1930-31 to 1989-90. The total area under cane cultivation stands at about 3405 thousand hectares with an average season of 158 days during November to April in a year. The geographical distribution of cane cultivation and hence of sugar factories is however concentrated mainly in the states of Uttar Pradesh, Maharashtra, Tamil Nadu, Karnataka, Andhra Pradesh, Gujarat, Haryana, Bihar and Punjab. Uttar Pradesh and Maharashtra account for more than 50 percent of the sugar plants in the country. Among the two, Maharashtra produces more sugar than UP although the latter produces more sugarcane of which almost 68 percent is diverted for the production of gur and khandsari. In Maharashtra, the yield rate is also higher at 78 to 97 tonnes per hectare, next to 91 to 105 tonnes per hectare in Tamil Nadu. On the aggregate, the total 396 sugar factories process around 42 percent of cane produced for the manufacture of plantation white sugar. On the other hand, gur is produced from 29 percent of the cane input in one lakh (approximately) tiny units and khandsari from 7 percent in 8000 registered units. The remaining 12 percent is used for seed and for direct consumption. In India, production of sugar from sugar beet is negligible (0.03 percent) because of its higher cost. Moreover, it does not produce the byproduct bagasse which is an additional source of energy.
Table 6.1 summarises the current position of the Indian sugar industry.

Table 6.1: Production Details of the Indian Sugar Industry

<table>
<thead>
<tr>
<th>Item</th>
<th>Unit</th>
<th>Quantity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Area under sugarcane</td>
<td>'000 hectare</td>
<td>3,618</td>
</tr>
<tr>
<td>Production of sugarcane</td>
<td>'000 tonnes/year</td>
<td>230,832</td>
</tr>
<tr>
<td>Yield of cane</td>
<td>tonnes/hectare</td>
<td>63.8</td>
</tr>
<tr>
<td>No. of factories in operation</td>
<td></td>
<td>396</td>
</tr>
<tr>
<td>Average capacity</td>
<td>tonnes/day (TCD)</td>
<td>2325</td>
</tr>
<tr>
<td>Total cane crushed</td>
<td>'000 tonnes/year</td>
<td>103,008</td>
</tr>
<tr>
<td>Total sugar produced</td>
<td>'000 tonnes/year</td>
<td>10,609</td>
</tr>
<tr>
<td>Exports</td>
<td>'000 tonnes/year</td>
<td>397</td>
</tr>
<tr>
<td>Recovery of white sugar</td>
<td>% cane</td>
<td>10.30</td>
</tr>
</tbody>
</table>


6.2.2 The Sugar Manufacturing Process

Sugarcane is comprised of two main components - fibre and juice. Fibre is the most abundant substance in sugarcane, formed by the cellulose in it. Fibre acts as the skeleton of sugarcane, which comes out as bagasse during cane-crushing. Starch, proteins and other organic constituents of sugarcane remain in the cellwalls. The juice contains sucrose, some inorganic non-sucrose substances and water. Sucrose is a disaccharide formed by the chemical bonding of simple sugars, namely, dextrose and fructose, also known as monosaccharides. These monosaccharides occur also in free form in sugarcane. They are called reducing sugars and dissolve in a thick syrup during processing along with other chemical constituents, while sucrose crystallizes to form the sugar. The inorganic chemicals such as silica, phosphates, chlorides, sulphates of potassium, sodium and magnesium are soluble in water and go into the juice. Sugar
processing essentially consists of a series of liquid-solid separation to isolate the sucrose from the sugarcane.

The manufacturing process in a typical sugar factory involves five basic processes:

(a) juice extraction;
(b) clarification of juice;
(c) evaporation and concentration of juice;
(d) crystallization of sugar; and
(e) crystal separation.

The first step of cane preparation is to cut the cane into pieces by motorised knives (or shredders or fibrizers) and then to put the obtained bagasse blanket for crushing in the milling tandem. The milling tandem comprises of a set of five to seven serially linked rolling mills. The rolls in each mill squeeze the bagasse blanket, which at this stage contains all the sugar, to extract the juice. From a serially repeated process of crushing and imbibation (i.e., giving a bath of warm or cold water to the bagasse blanket prior to entering the last mill in the tandem) the mixed juice is produced along with the final bagasse. The bagasse goes to the boiler house and the mixed juice for clarification.

The objective of clarification is to change the soluble non-sugars into insoluble solids and then separate them from the juice along with other colouring particles, by sedimentation. This is done by adding milk-of-lime and sulphur dioxide or carbon dioxide and heating. Accordingly, the process is known as sulphitation or carbonation. A heavy precipitate containing insoluble matters such as lime salt, albumin, fats, waxes and gums is thus formed. Addition of sulphur dioxide/ carbon dioxide eliminates the
colouring matters in the juice. Finally, all these are separated by sedimentation. The clarified juice thus obtained, contains water. Subsequently, this water has to be evaporated to reduce the cane juice into a thick viscous syrup, thereby increasing the concentration of the soluble matter in it.

In the evaporation process, steam instead of direct heat, is used to heat the cane juice in order to avoid caramelization. The clarified juice is heated in a number of serially connected vessels. The technology used is known as the vacuum pan technology. The juice is heated in vacuum in order to obtain a lower boiling point of juice of 60°C to 70°C and also a reduced boiling time. The vacuum in a vessel increases from one to the next so that the pressure and boiling point in successive vessels reduce continuously. The contents of each vessel are 'boiled' by the vapour coming out from the previous one while the juice in the first vessel is boiled by steam. Finally, the syrup comes out of the last of the quad or quintuple of vessels as a concentrate ready for crystallisation.

The massecuite (syrup) coming from the vacuum pans is cooled under the crystallisation process. The main feature of crystallisation is the deposition of sucrose. Three grades of massecuites, namely A, B and C, produce A-crystal sugar; B-crystal sugar and C-crystal sugar respectively. The residual fluid is known as mother liquor or molasses.

Subsequently, the crystals are separated from the mother liquor by fast rotation in a centrifuge. Different grades of sugar, namely, A, B and C are then obtained, dried and bagged for sale. Chart 6.1 describes the process flow of a typical sugar plant.
CHART 6.1 Process Flow Diagram for Production of Crystal Sugar
6.2.3 Features of the Manufacturing Process

A. Bagasse Production

The size of a sugar plant is measured in terms of the daily crushing capacity. Accordingly, they are broadly categorised as:

a. 1250 tonnes of cane crushed per day (TCD);
b. 2000/2500 TCD;
c. 3500 TCD;
d. 5000 TCD;
e. above 5000 TCD.

Recovery of sugar is about 10.3 percent cane* put under crushing on the average. The production of byproduct bagasse is around 28 to 30 percent of cane crushed (note that cane crushed is 100 percent of cane put to crushing). The bagasse coming out of the extraction mills contain almost 50 percent moisture on wet basis** and is generally called mill wet bagasse. The gross calorific value of bagasse is approximately 2340 kilo calorie per kilogram giving around 2.02 to 2.20 kg of steam per kg of bagasse. The use of bagasse in the boiler house for captive power and steam generation is an existing practice in sugar mills. The mill wet bagasse is directly used in the bagasse boiler for generation of high pressure steam which in turn drives the turbo-alternator. The power thus generated is used to meet the motive power requirements of the mill. The low pressure exhaust steam from the turbo-alternator then goes to different consumption

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* The unit of measurement in a sugar manufacturing process viz., percent cane, is the percentage of usage in the process with respect to the total cane crushed.

** Moisture measurement on wet basis is defined as the ratio of weight of moisture alone to the weight of the wet material.
points of the process with steam load. A typical sugar plant in the organised sector is thus self-sufficient in fuel and operates as a cogenerator, often leaving surplus bagasse as well.

Other than being used as fuel, bagasse can also be used as fertiliser, cattle feed and also in the pulp and paper industry. In view of the surplus bagasse production over the amount used as fuel, these alternative uses may also be adopted.

B. Steam Parameters and the Steam Balance

Most of the existing sugar plants currently in operation are equipped with boilers generating steam at 22 ata* 340°C for 1250 TCD and at 33 ata 380°C for 2500 TCD-capacity. The standard steam generation capacity is around 32 tonnes per hour (tph) for each boiler and generally two such boilers suffice for captive steam and power generation. The typical configuration for a 5000 TCD plant is 45 ata 440°C for two bagasse boilers of 40 tph capacity.

The high pressure steam outlet from the boiler drives the turbo-alternator to generate power. The turbine is generally of back pressure type, exhausting low pressure steam at 1.5 to 2 ata. This steam goes to the different centres such as:

a. Juice heater;
b. Evaporator;
c. Fans;
d. Vacuum Pans.

Total exhaust steam (at 1.5 ata) requirement is around 46.8 percent of cane, with the evaporator bodies consuming about 93 percent of the total exhaust steam consumption.

* 1 ata = 1.033 kg/cm²
The evaporator bodies contain the heat exchangers called *calendria* which consist of a number of tubes. Steam is injected to heat the syrup which now travels through these tubes. The steam circulates in the enclosed space outside the tubes. The steam consumption is less if the heating surface is larger. The excess vapour goes to the downstream operations of pan boiling.

The consumption points of *live steam* i.e., the steam emerging directly from the boilers, other than power turbines are:

- a. Fibrisers in cane preparation;
- b. Mills for cane crushing;
- c. Fans.

Depending on the initial pressure and temperature of the boiler outlet steam, the consumption of live steam varies from 30.62 percent to 46.70 percent cane. The prime movers, namely, fibriser, mills and fans and turbo alternators together consume steam of about 46.7 percent cane at 21 ata 340°C. This can be improved to 30.62 percent by using boilers generating steam at 40 ata 400°C.

The centrifugal stations and sulphur burners consume steam at 6 ata, obtained from high pressure steam through pressure reducing stations. This comprises about 3 percent cane. The make up steam from process is 0.1 percent cane and about 2.2 percent cane goes as condensation loss.

The overall steam balance thus stands at 52.0 percent cane (46.7 percent cane for the prime movers plus 3 percent cane for centrifugal stations plus 0.1 percent cane as make up steam plus 2.2 percent cane as condensation loss) with the prime movers also exhausting steam at 1.5 ata of 46.7 percent cane.
The boiler capacity varies between 20 tph to 30 tph for 21 ata boilers and it is around 40 tph for 32 ata to 45 ata boilers.

C. Power Generation and Consumption in the Plant

The unique feature of the sugar industry is that it produces its own power for running prime movers of its different unit operations. Traditionally, a typical sugar plant consumes bagasse to the tune of 27 percent cane for internal consumption in the form of steam and power.

Most of the sugar plants have back pressure turbines (with 1.5 ata back pressure), although some modernised plants have condensing extraction type turbines with extraction pressure of 6 to 8 ata.

Table 6.2: Electricity Consumption in Sugar Manufacturing Process

<table>
<thead>
<tr>
<th>Operation</th>
<th>2500 TCD plant (a)</th>
<th>5000 TCD plant (b)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Cane handling, milling</td>
<td>0.81</td>
<td>1.4</td>
</tr>
<tr>
<td>Juice handling, sulphitation and filtration</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. Juice heating, bagasse</td>
<td>0.68</td>
<td>1.0</td>
</tr>
<tr>
<td>Handling and pan boiling</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3. Boiler house</td>
<td>0.53</td>
<td>1.2</td>
</tr>
<tr>
<td>4. Crystallisers and centrifugals</td>
<td>0.62</td>
<td>2.0</td>
</tr>
<tr>
<td>5. Sugar handling, drying, grading, water service,</td>
<td>0.42</td>
<td>1.5</td>
</tr>
<tr>
<td>spray ponds and workshop</td>
<td></td>
<td></td>
</tr>
<tr>
<td>and office</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. Total consumption</td>
<td>3.06</td>
<td>7.1</td>
</tr>
</tbody>
</table>

Source: (a) Dhampur Sugar Mills, UP (2500 TCD), report given to NFCSF; (b) Daurala Sugar Mills, UP (5000 TCD) based on field study.

For a typical 2500 TCD sugar plant, total electrical energy consumption is around 3 to 3.5 MW while a 5000 TCD plant consumes about 7 to 7.5 MW. The in-house electricity requirement is lower than what can be generated from the available bagasse.
The overall electrical energy consumption in various operations of the cane sugar manufacturing process has been summarised in table 6.2.

The figures in Table 6.2 show the total in-house consumption pattern of electricity, net of losses and without any supply/sale of power to the grid or any ancillary unit. It may be interesting to examine whether the available bagasse can be used to cogenerate a greater quantity of power giving an exportable surplus after meeting the load in-house and/or ancillary units. Some supplementary fuel may also be used for steam raising, if that gives a cost-effective cogeneration of extra power. It may further be analysed whether the existing boilers and turbines can generate additional power or need replacement and retrofit. Alternative combinations of boilers with higher steam parameters and condensing type turbines may be installed to generate even a greater quantity of steam and power which may be cheaper. Apart from the crushing season, i.e., November to April, these facilities may also be extended with alternative fuels instead of bagasse if the boilers are multifuel-fired in nature. Such alternative options have been examined in the following sections, based on a typical sugar plant surveyed.

6.3 DETAILS OF THE SUGAR PLANT UNDER STUDY

The sugar plant under investigation is one of the sulphitation type with a crushing capacity of 5000 TCD, located in Daurala, U.P., India. It also has an allied organic and chemical plant and also a distillery. These ancillary units are general features of a sugar plant which optimises the use of byproduct molasses. The in-house cogenerated power is supplied to these ancillary plants in addition to meeting the entire load of the sugar plant. The case study of such a plant has been aimed at finding:

i) the potential for additional power cogeneration with the current infrastructure as compared to the existing operational practice;
ii) the scope for capital investment in improving the boiler-turbine designs in order to attain higher energy efficiency and power generation in season;

iii) the potential for power generation during the industry’s off-season, i.e., summer.

The new configurations of boilers and turbines can be considered either as cases of partial capital investment in the existing structure or as feasible options for new plants, set up with the objective of additional power generation for supply outside the plant. The various model options will reflect the energy-efficiency and economy in terms of the cost of cogeneration and hence the supply price. The costs would imply the relative attractiveness of the options and the relative cost-economy due to the use of bagasse instead of the expensive fossil fuels. The extent of energy-efficiency would depend on the machine configurations.

Before formulating the optimisation problem for cogeneration of power in sugar plant under various options, the operational details of the plant, and the current machinery configurations have been described below.

(a) Operational Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cane crushed (average)</td>
<td>5322.8 tonnes per day</td>
</tr>
<tr>
<td>Bagasse produced</td>
<td>1680.76 tpd (31.58% cane)</td>
</tr>
<tr>
<td>Net bagasse availability after storage and refining</td>
<td>1650.02 tpd (31.0% cane)</td>
</tr>
<tr>
<td>Operational hours (average)</td>
<td>23 hours per day</td>
</tr>
<tr>
<td>Cane crushing period</td>
<td>165 days (November to April)</td>
</tr>
<tr>
<td>Moisture content of bagasse</td>
<td>50%</td>
</tr>
<tr>
<td>Fibre content in bagasse</td>
<td>14%</td>
</tr>
<tr>
<td>Calorific value of 50% mill wet bagasse</td>
<td>2340 KCal/kg</td>
</tr>
</tbody>
</table>

6-13
Steam-bagasse ratio 2.02 to 2.20 kg/kg
Any other fuel option Coal
Mill turbines are driven by steam (not electric motor)
Steam generation (average) 55% cane
Purchase price of cane Rs.740/ton
Purchase price of coal Rs.850/ton
Sale price of bagasse Rs.250/ton at (mid-1995 prices).

(b) Plant Machinery

There are seven boilers (B) with different pressure-temperature parameters and steam generating capacity. Two spreader stoker travelling grate boilers supply 40 tph steam each to the 42 kg/cm² steam header at 400°C temperature (approx.). One 35 tph spreader stoker travelling grate boiler supplies steam to the 32 kg/cm² header at 400°C ± 12°C while three 30 tph (one horse-shoe furnace and two spreader stocker) boilers supply to the 19.34 kg/cm² header at 315°C. There is also one 10 tph boiler with steam parameters of 20 kg/cm², 300°C. The capacity utilisation on the whole, is around 69 percent and efficiency* is 65 to 68 percent varying for horse-shoe and spreader stocker furnaces. No boiler has a bagasse drier and all boilers can use multifuel, namely, both coal and bagasse.

The turbines installed are five in number, of which four are conventional back pressure steam turbines (BP-ST) and one is a condensing-extraction steam turbine (CEST). The three BP turbines are of 2.5 MW generation capacity and one with 3 MW

* Boiler efficiency is defined as the ratio of the enthalpy of output steam to the heat content of the input fuel.
where all have back pressures of 1.5 kg/cm². The 1 x 4.5 MW CEST has a condensation rate of 4 tph. The total power generation capacity is 15 MW. The specific steam consumption in BP and CEST turbines are 11.92 kg/KWH and 5.8 kg/KWH respectively.

The boiler and turbine configuration is presented in the steam balance of chart 6.2.

The 42 kg/cm² steam header with 80 tph steam generation from B#1 and B#2 of chart 6.2 supplies to the

i) two 2.5 MW BP turbines (P1 and P2),

ii) 32 kg/cm² header through pressure reducing station PRDS#1 and

iii) 11 kg/cm² header through PRDS#4

The 32 kg/cm² steam header gets its supply from the PRDS#1 and the 35 tph boiler (B#3) and the load points of this header are-

i) one 3.6 MW BP turbine (P3),

ii) one 4.5 MW CEST (P4) and

iii) the 19.34 Kg header through PRDS#2.

The next header is the 19.34 kg/cm² header getting steam from PRDS#2 and the 3 x 30 tph and 1 x 10 tph boilers (B#4, B#5, B#6, B#7). This header supplies steam to the

i) mill turbines at the rate of 35.96 tph,

ii) to the organic plant at 2.75 tph,

iii) to one 2.5 MW BP turbine (P5) and

iv) to the lowest header viz., 11 kg/cm² through PRDS#3.
CHART 6.2 Steam Balance Diagram for Sugar Plant Operation

as per Model 1.

6-16
The lowest pressure steam supply at 11 kg/cm² goes to

i) the centrifugal stations, sulphur burning and sugar drying in the sugar plant at 6.69 tph,

ii) the chemical plant at the rate of 3.09 tph and

iii) the refinery and distillery at 0.6 tph, giving a total load at this header of 10.38 tph only.

The exhaust steam at 1.5 kg/cm² from the BP turbines, mill turbines and the extracts from CEST are supplied to the juice heaters, evaporator bodies, pan stations and vacuum cells. The total exhaust steam availability is around 138.96 tph, with a break-up of -

- 2 x 25 tph from the 2 x 2.5 MW BP turbines at 42 kg/cm² header,
- 1 x 26 tph from the 1 x 3 MW BP turbines at 32 kg/cm² header,
- 1 x 27 tph from the 1 x 2.5 MW BP turbines at 19.34 kg/cm² header, and
- 35.96 tph from the mill turbines.

The total live steam generation in the boiler house is 141.71 tph, out of which 138.96 tph come out as exhaust steam at 1.5 kg/cm² from different prime movers and pressure-reducing stations while 2.75 tph steam is generated at the 19.34 kg/cm² header for the supply of the organic plant.

The above configuration of power generation matches with the power load for process (as summarised in Table 6.2) and the allied plants. Current requirement of power is about 9.4 MW of which 7.2 MW goes to the sugar plant and about 2.2 MW to the allied plants. The plant's current operating mode does not leave any room for cogeneration of surplus power to be supplied to the grid. However, the practice of cogeneration is maintained for in-house self-sufficiency in power. The cogeneration cycle in the sugar plant is one of the topping cycle variety (i.e., generation of power...
takes place first and the exhaust low pressure steam from the power turbines is fed into the manufacturing process), as is clear from the live and exhaust steam balances. The process flow diagram of steam and power as presented in chart 6.2 shows the four steam headers with their respective demand and supply points. The last and fifth header is also shown in the chart as the line for the exhaust steam of 1.5 kg/cm².

The process flow diagram is the pictorial representation of the basis for the steam and power balance equations, to be formulated in the next section. It depicts the distribution of steam throughout the plant and the generation of power therefrom.

6.4 THE OPTIMISATION PROBLEM

The linear optimisation problem is to estimate the surplus potential of cogenerated power using the available byproduct bagasse, in addition to the in-plant power load. This has been formulated as a problem of power output maximisation, constrained by the balances of steam and power between consumption and generation and the capacity limits of the machines. A subsequent optimisation exercise minimises the fuel cost for generating power only to meet the in-house requirement, subject to the same set of constraints. While the latter will give the minimum cost of power generation for in-house requirement, the results of the maximisation exercise may be used to compute the fuel cost of generating the maximum quantity of power under a given infrastructure. The cost differential will give the additional fuel cost of cogenerating power over that of plant-use-only. Dividing the total additional cost by the surplus amount of cogenerated power, one may compute the per unit fuel cost of the exportable surplus power. The final supply price of saleable cogenerated power may be computed by adding the per unit fuel cost to the capital cost amortised over the life of the brownfield or greenfield plant and the cost of operations and maintenance. This method of calculating the price of
cogenerated power is referred to as the 'Economic Method' (National Conference on Cogeneration, CEI, New Delhi, 1991). However, the cogenerator's power output maximisation exercise is justified if the sale of extra power earns additional profit. In other words, the cogenerator needs to get a higher offer price from the purchaser than its own supply price. However, the cost minimisation exercise has to be carried out as a rational firm's choice.

The optimisation methodology may be used as a valuable tool in estimating the optimal fuel-mix of bagasse and purchased coal (if any) which would maximise power output or minimise fuel cost of generating power for plant-use-only. It is easy to visualise that one may further extend this method to compute optimal fuel-mixes in order to minimise cost to meet any given load or to maximise power output in any operating environment of cogeneration.

The cost minimisation problem does not exist during off-season when there is no power requirement in the plant. Accordingly, the optimisation problem for off-season reduces only to the estimation of the potential for the maximum power output, based on stored bagasse and/or other purchased fuels. The fuel cost of cogenerated power during the off-season may therefore be computed directly and so also is the corresponding supply price.

The in-season optimisation exercises therefore are to

maximise power output

\[ \sum_i p_i, \quad i = 1,2,...,5 \]  

where \( p_i \) denotes the output of turbine \( i \).
and then to

minimise fuel cost

$$\sum_i \pi_c c_{fi} + \sum_i \pi_b f_i, \quad i = 1, 2, \ldots, 7$$

... (B)

where

$$\pi_c$$ : price of coal fuel

$$\pi_b$$ : price of bagasse

c_{fi} : coal fuel to boiler i

fᵢ : bagasse fuel to boiler i.

The price of bagasse, which is a byproduct of the process, is considered as a component of cost because bagasse has an alternative sale price in the market. To the producer, therefore, bagasse has an opportunity cost of otherwise being sold, say, to the paper plant and earning revenue for the producer. In that sense, the use of bagasse means a cost for the cogenerator who is forgoing that revenue. Hence, the sale price of bagasse is included in the power generator's total fuel cost to be minimised, because, the cogenerator would try to recover that part of the cost too while setting his sale price of power.

Among the various constraints of the optimisation exercises, are the steam balances at each header. In other words, the process steam demands are to be met at the relevant pressure headers. It is further constrained by the input-output relationships of the boilers, turbines and their respective capacities. Fuel availability puts the final constraint. Therefore, the constraint equations are formulated from

(a) the availability of fuel,

(b) the steam generation i.e., the boiler equations,

(c) the power output or turbine equations,
(d) the steam balance and
(e) the capacity of the machines.

(a) The Fuel Constraints

The total availability of bagasse is dependent on the cane crushing capacity. The net bagasse available is 31 percent (approximately) cane and that is the maximum bagasse fuel available for the boilers.

The bagasse fuel consumption (fi) in each boiler i, i=1,2,...,7 will then add up to the total bagasse fuel less than or equal to the net bagasse available, namely, f-max. The bagasse constraint thus becomes

\[ f_1 + f_2 + f_3 + f_4 + f_5 + f_6 + f_7 \leq \text{f-max} \]

or symbolically,

\[ \sum_i f_i \leq \text{f-max}, \quad i = 1, 2, \ldots, 7 \]  \hspace{1cm} (1)

The average bagasse availability in season is recorded as 71.74 tph. Constraint (1) may therefore be specified as:

\[ \sum_i f_i \leq 71.74 \]  \hspace{1cm} \text{(1')}

However, this constraint will not be there during off-season if there is no stored bagasse and boilers are fired with coal only.

The use of supplementary coal is, however, an open option and in that sense does not have any availability limitation. The total use of coal (cf) is therefore the sum of the coal consumed in each boiler, at the optimum. The constraint is a weaker one, leaving room for any amount of coal use (cf), viz.,

\[ cf_1 + cf_2 + cf_3 + cf_4 + cf_5 + cf_6 + cf_7 \leq \text{cf} \]
or symbolically,

\[ \sum_{i} c_{fi} \leq c_{f}, \quad i = 1, 2, \ldots, 7 \]  \hspace{1cm} \ldots(2)

(b) The Boiler Equations

The boilers under operation are open for both fuels, namely, bagasse and coal. The steam generation in each boiler depends on the steam to bagasse ratio and the steam to coal ratio. The calculations for obtaining these two crucial coefficients of the boiler equations are presented in Table 6.3. Given the capacity and the parameters of the steam raised, together with boiler efficiency, one can calculate the enthalpy (i.e., the total heat content of the steam generated), heat output and heat input. Accordingly, the amount of bagasse or coal fuel to be burnt for generating the specified heat input can also be computed and the steam-to-bagasse and steam-to-coal ratios obtained therefrom.

Table 6.3: The Enthalpy Calculation for Steam-to-Fuel Ratios

<table>
<thead>
<tr>
<th>Rows</th>
<th>Unit</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Capacity</td>
<td>tph*</td>
<td>40</td>
<td>40</td>
<td>35</td>
<td>30</td>
<td>30</td>
<td>30</td>
<td>10</td>
</tr>
<tr>
<td>2. Steam raised (69% of capacity)</td>
<td>tph</td>
<td>27.73</td>
<td>27.73</td>
<td>24.27</td>
<td>20.8</td>
<td>20.8</td>
<td>20.8</td>
<td>6.9</td>
</tr>
<tr>
<td>3. Steam parameters</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Pressure</td>
<td>ata</td>
<td>42</td>
<td>42</td>
<td>32</td>
<td>19.34</td>
<td>19.34</td>
<td>19.34</td>
<td>20</td>
</tr>
<tr>
<td>(b) Temperature</td>
<td>°C</td>
<td>400</td>
<td>400</td>
<td>400</td>
<td>315</td>
<td>315</td>
<td>315</td>
<td>300</td>
</tr>
<tr>
<td>4. Enthalpy</td>
<td>KCal/Kg</td>
<td>727.7</td>
<td>727.7</td>
<td>733.3</td>
<td>694.4</td>
<td>694.4</td>
<td>694.4</td>
<td>694.0</td>
</tr>
<tr>
<td>6. Efficiency</td>
<td>%</td>
<td>0.68</td>
<td>0.68</td>
<td>0.68</td>
<td>0.65</td>
<td>0.65</td>
<td>0.65</td>
<td>0.65</td>
</tr>
<tr>
<td>9. Steam to bagasse</td>
<td>ton/ton</td>
<td>2.18</td>
<td>2.18</td>
<td>2.17</td>
<td>2.19</td>
<td>2.19</td>
<td>2.19</td>
<td>2.19</td>
</tr>
<tr>
<td>10. Coal required</td>
<td>tph</td>
<td>5.94</td>
<td>5.94</td>
<td>5.23</td>
<td>4.44</td>
<td>4.44</td>
<td>4.44</td>
<td>1.47</td>
</tr>
<tr>
<td>11. Steam to coal</td>
<td>ton/ton</td>
<td>4.67</td>
<td>4.67</td>
<td>4.64</td>
<td>4.68</td>
<td>4.68</td>
<td>4.68</td>
<td>4.69</td>
</tr>
</tbody>
</table>

*tonnes per hour.

Figures in rows 1 and 3 describe the boiler capacity and steam parameters, as obtained from the plant. The efficiency figures in row 6 are the standards used in the industry for spreader stoker travelling grate type boilers and spreader stoker horseshoe...
furnace type boilers respectively. The enthalpy of the system has been derived from the Steam Table (Tribus) and presented in row 4. The heat output (in row 5) is the product of the enthalpy and steam raised while the heat input (in row 7) is the quotient of heat output and efficiency. The bagasse and coal requirements (rows 8 and 10 respectively) are obtained by dividing the heat input (row 7) by the calorific value of bagasse (=2340 Kcal/kg) and coal (=5000 Kcal/kg) respectively. Finally, the steam-to-bagasse ratio (in row 9) is calculated by dividing the steam raised (row 2) by the bagasse requirement (row 8). Similarly, the steam-to-coal ratio (row 11) is obtained by dividing the steam raised (row 2) by the coal requirement (row 10). The steam-to-coal ratio is almost double of the steam-to-bagasse ratio. The two steam-to-fuel ratios corresponding to each of the seven boilers are obtained and can now be used in writing the boiler equations as:

\[ \text{bis} = \alpha_i(f_i) + \beta_i(c_{fi}), \quad i = 1, 2, 3, \ldots, 7 \]  

... (3)

where

- \( \text{bis} \): steam output of boiler \( i \),
- \( f_i \): bagasse fuel to boiler \( i \),
- \( c_{fi} \): coal fuel to boiler \( i \),
- \( \alpha_i \): steam-bagasse ratio,
- \( \beta_i \): steam-coal ratio.

There will be seven such boiler equations, corresponding to the seven boilers.

(c) The Turbine Equations:

The power output (\( p_i \)) of the turbine \( i \) can be expressed as the following (Tribus):

\[ p_i = \mu_i*(p_{is}) + \delta_i*(p_{exti}) + \phi_i, \quad i=1, 2, 3, 4, 5 \]  

... (4)

where

- \( p_{is} \): rate of flow of steam at inlet of turbine \( i \),
pexti : extraction from the turbine i,

\( \mu_i, \delta_i \) : the respective power generation coefficients,

\( \phi_i \) : constants.

Out of the five turbines, four are of the back-pressure type (BP-ST) with no extraction. Therefore, four turbine equations reduce to

\[
pi = \mu_i * (pis) + \phi_i, \quad i = 1, 2, 3, 4
\] ...

while that of the fifth remains as in the form (4). The coefficients \( \mu_i \) and \( \phi_i \) are obtained from real-life plant data for performance of turbo-generators. A study of weekly performance data has shown that the 2 x 2.5 MW, BP-ST sets (P1, P2) have 2 x 25 tph steam inlet at 42 kg/cm\(^2\) and generate on an average around 2.2 MW of power. The performance curve can be fitted on the basis of such figures, collected from the plant at four points of time. Similarly, the performance data for the other BP turbines, namely, the 1 x 3 MW (P3) and 1 x 2.5 MW (P4) BP-TG sets on an average are - steam inlet of 26 tph at 32 kg/cm\(^2\) 400°C and 27 tph at 19.34 kg/cm\(^2\) 315°C respectively, with the corresponding power generation of 2.6 MW and 2.2 MW. Therefore, performance curves could be fitted for all the four turbines and the parameters estimated. The coefficients estimated are:

\[
\mu_1 = \mu_2 = 0.104, \mu_3 = 0.103, \mu_4 = 0.123;
\]
\[
\phi_1 = \phi_2 = -0.42, \phi_3 = -0.52, \phi_4 = -0.50.
\]

The equation for the fifth turbine is similarly estimated from point-to-point data on performance. The steam inlet for the 1 x 4.5 MW CEST turbine P5 is 30 tph at 32 kg/cm\(^2\) 400°C, extraction is 26 tph at 1.5 kg/cm\(^2\) and power generation is 2.5 MW, on an average. The estimated parameters for this equation are:

\[
\mu_5 = 0.22, \delta_5 = -8.8 \text{ and } \phi_5 = -1.36.
\]
Five turbine equations are thus obtained, giving the power output as functions of input and extraction of steam.

(d) The Steam Balance

The crucial constraints in the optimisation problem come from the steam load balancing at each steam header. The supply of steam from various boilers at specified pressure and temperature has to meet the demand for steam at the inlets of power turbines, pressure reducing stations (PRDS) and consumption points in the process.

The 42 kg/cm² 400°C steam header gets the steam supply b₁s and b₂s from boilers B#1 and B#2, and goes to the 2 x 2.5 MW BP turbines, P₁ and P₂. It also supplies to the next 32 kg/cm² 400°C header through PRDS numbered (prd₁s) and to the 11 kg/cm² header through PRDS numbered 4 (prd₄s). The steam balance at the 42 kg/cm² header thus becomes

\[ b₁s + b₂s \geq p₁s + p₂s + prd₁s + prd₄s \] \hspace{1cm} \cdots (6)

where

- \( bᵢs \): steam raised in boiler \( i, i = 1, 2 \),
- \( pᵢs \): steam inlet to power turbine \( i, i = 1, 2 \),
- \( prd₁s \): pressure reduced steam from 42 kg/cm² header to 32 kg/cm² header,
- \( prd₄s \): the same to 11 kg/cm² header.

The steam supply to the 32 kg/cm² header is from \( prd₁s \) as already mentioned, and the 1 x 35 tph boiler B#3 (steam supply denoted by \( b₃s \)). The load points are the 1 x 3 MW BP-TG set (P₃), the 1 x 4.5 MW CEST (P₄) and the pressure reduced steam to the 19.34 kg/cm² header (prd₂s). The constraint becomes

\[ b₃s + prd₁s \geq p₃s + p₄s + prd₂s \] \hspace{1cm} \cdots (7)

where
pis: steam input to the power turbine, $i = 3, 4$ and the other notations have meanings as above.

The third steam balance equation corresponds to the 19.34 kg/cm$^2$ header. The four boilers, namely, 3 x 30 tph boilers B#4, B#5, B#6 and the 1 x 10 tph boiler B#7 raise steam at this configuration to supply to the 1 x 2.5 MW BP turbine (P5), the mill turbines and fibrizers at 35.96 tph and also to the allied organic plant at 2.75 tph. This header also gets steam from the 32 kg/cm$^2$ header through prd2S. The steam balance at this header is

$$b_{4s} + b_{5s} + b_{6s} + b_{7s} + prd_{2s} \geq p_{5s} + prd_{3s} + 38.71$$

where prd$_{3s}$ is the pressure reduced steam supply to the 11 kg/cm$^2$ header and 38.71 tph is the total steam demand by the mill turbines and the organic plant. The other notations have their usual meanings.

The 11 kg/cm$^2$ header gets steam only through prd$_{3s}$ and prd$_{4s}$ and meets an average steam load of 10.38 tph, of which 6.69 tph goes to the centrifugal stations, sulphur burning and sugar drying; 3.09 tph to the allied chemical plant and 0.6 tph to the refinery and distillery. Therefore, write

$$prd_{3s} + prd_{4s} \geq 10.38$$

The exhaust steam at 1.5 kg/cm$^2$ is used throughout the plant in juice heating, pan stations, and evaporator bodies. The exhaust steam comes from all the five power turbines and the mill turbines. The exhaust from each BP power turbine $C_i$, $i = 1,2,3,5$, is the same as the turbine inlet pis, $i = 1,2,3,5$. The extraction (pext4) at 1.5 kg/cm$^2$ from the CEST, viz., P4, would provide steam for process, say, C6. Finally, the entire exhaust steam $C_5 = 35.96$ tph from the mill turbines would also add to the 1.5 kg/cm$^2$ supply of steam. The total requirement of steam at 1.5 kg/cm$^2$ is 138.96 tph. It is
evident that the total exhaust steam from the five power turbines and mill turbines should be at least 138.96 tph. This poses the last constraint. Therefore, the balance equations for the 1.5 kg/cm$^2$ exhaust can be summarised as:

\[
\begin{align*}
Ci &= pis, \quad i=1,2,3,4 \\
C5 &= 35.96 \\
C6 &= pext4 \\
\sum_{i=1}^{6} Ci &\geq 138.96
\end{align*}
\]  

... (10)

The figures used as the average steam load (in tph) are taken from the plant as the 152 days' average in the current season till the date of data collection.

(e) The Capacity Constraints

All the boilers for steam raising and turbines for power generation are open for operation. But standard industrial engineering practices suggest that boilers operate between 30 percent to 100 percent of capacity while turbines operate between 20 percent and 100 percent of capacity (Spalding & Cole). This gives the capacity constraints as:

\[
\begin{align*}
.30 \ (bimax) &\leq bis \leq bimax; \\
.20 \ (pimax) &\leq pi \leq pimax
\end{align*}
\]  

... (11)

where

bimax : capacity of boiler i, i = 1, 2, ..., 7

pimax : capacity of turbine i, i = 1, 2, ..., 5.

The above equations and/or inequalities provide the constraints to the optimisation
In other words, along with the boiler and turbine equations, fuel availability, machine capacity and steam balance, there will be a constraint arising out of the power demand of 9.4 MW in plant which is to be met by the power generation in the given turbines. This second exercise will give the minimum fuel cost required to produce power to meet the captive load of 9.4 MW only. On the other hand, the power output maximisation exercise gives the associated fuel cost of producing the maximum quantity of power. Now, both the cost figures involve (a) the cost of raising steam and (b) the cost of power generation. The difference between the cost of maximum power generation and the minimum cost to produce for the in-house power load would therefore involve the cost of steam raising too. However, this extra steam generation for maximum power output is required for the additional power generation and not for the process. This cost should therefore be accounted in the cost of extra power generation, namely, surplus cogeneration of power under any given structure.

The optimisation exercises give the fuel cost of cogeneration, as the cost differential in season and directly from the power output maximisation exercise during off-season. The existing practice in the mill is to generate power for in-plant load in season only. Therefore this infrastructure may not be very cost-effective if extended to off-season generation. One may, therefore, study alternative boiler-turbine configurations with yearlong efficient and cost-economic cogeneration in view. Four alternative models have been studied for the purpose. Since the boilers are multifuel in type they have been retained for both bagasse and coal firing during season and off-season. Only the turbine configurations, varying in the number of BP-ST and CEST, have been studied. Model I describes the existing machinery for maximum possible power generation, which is
currently unutilised. Other models 2, 3, 4 have been conceptualised as alternative configurations and capacity.

However, the final supply price of cogenerated power along any option, includes fixed and working capital and other maintenance charges. Such calculations have been done in a latter section. For capital cost estimation, all models have been analysed both as greenfield and brownfield plants. While greenfield plants involve capital cost of installing the entire capacity, the brownfield plants involve cost of the extra capacity installation or replacement of the particular turbines. Subsequently, the final supply price of cogenerated power in the four models vary from greenfield to brownfield options and also from season to off-season.

The optimisation exercises in the following sections estimate the cogeneration potential, fuel cost and the coal-bagasse fuel-mix in the alternative models. The linear programmes have been run under the computer package LINDO.

6.5 THE EXISTING OPTION FOR SURPLUS POWER GENERATION: MODEL 1 (4-BPST & 1-CEST)

6.5.1 Power Output Maximisation in Season

The objective of this linear optimisation exercise is to calculate the potential for the maximum possible power generation, subject to the aforementioned constraints with the existing plant and machinery. All the seven boilers and five turbines are allowed for full operation. Both bagasse and purchased coal are taken to be the available fuels.

The linear programme is formulated to obtain the maximum possible power output for both in-house load and exportable surplus, as follows:
maximise \( p1 + p2 + p3 + p4 + p5 \)

subject to

constraints (1)' through (11). \( \ldots \) (M.1A)

Here and in further subsections, the statements of the optimisation problems have been numbered following the convention (M.ij) where \( i=1,2,3,4 \) denotes the four models and \( j=A,B,C \) denotes the objective functions (equations A & B) while C refers to the off-season version of A.

**Results:**

The maximum value of the objective function, i.e., the maximum power output is 15 MW. This implies an excess of 5.6 MW power generation over and above the in-house power load of 9.4 MW including the allied plants. All turbines produce at their respective maxima.

The boilers are operating at near maximum with B#1, B#2, producing 40 tph each, B#3 at 35 tph and B#4 at 30 tph. The boiler, B#5, raises steam at 26.37 tph and B#7 at 9 tph which are almost 87 percent to 90 percent of capacity. The only boiler operating at less than full capacity is B#6, raising steam at 9 tph. However, since all the turbines are generating at their respective maxima, this sub-optimal utilisation of one boiler's capacity has to be accounted for by the lack of demand for live steam at the respective high pressure. Total live steam generation is 189.37 tph, while the current need for live steam is 138.96 tph in the sugar plant and 2.75 tph in the allied plants. Therefore, the extra 50.41 tph live steam generation is solely for the purpose of surplus power generation.

With all the turbines generating at full capacity, the pass-out steam (pis) and exhaust steam (Ci) are sufficient to meet the load at 1.5 kg/cm² and there is no need for
extraction from the CEST. Total exhaust steam availability is 149.6 tph, marginally higher than the in-plant load.

The most striking feature of the optimal solution lies in the optimal use of bagasse and near-zero use of coal. All the boilers, except for B#1, consume bagasse, making a total bagasse consumption of 69.127 tph. The total quantity of available bagasse is 71.74 tph, net of refining. Therefore, a bagasse saving of only 2.61 tph is there. Bagasse, which comes as a byproduct of cane crushing, is optimally utilised for cogeneration of additional power. On the other hand, none of the six boilers B#2, B#3, B#4, B#5, B#6, B#7 consume any purchased coal. Despite the multi-fuel choice, all the boilers in season run on bagasse only. It is only B#1 which consumes 8.56 tph of coal. The excess 2.61 tph of bagasse was not sufficient to raise 40 tph of steam at 42 kg/cm² from B#1. At the optimum, therefore, it consumes only 8.56 tph of coal to raise 40 tph steam. This particular result regarding the fuel-mix is the focal point of the study on cogeneration potential in an existing sugar plant. The definite advantage of having byproduct bagasse is, thus, optimally made use of in generating additional exportable power during the cane crushing season.

The total fuel cost to produce the maximum output of 15 MW can now be calculated. Boiler coal price has been quoted as Rs.850 per tonne, for mid-1995 by the industry. Bagasse has an alternative sale price of Rs.250 per tonne at factory-gate. Total bagasse consumption per hour is therefore worth a value of Rs.250 x 69.127 = Rs.17,281.75. The cost of purchased coal per hour is Rs.850 x 8.5 = Rs.7280.25 giving the value of total hourly fuel consumption as Rs.24,562. As explained earlier, this total hourly fuel cost includes those of steam generation and power generation as...
well. This cost will be compared with the minimum cost of generating power for in-
house load as calculated in the next section, for computing the fuel cost of cogeneration.

6.5.2 Fuel Cost Minimisation in Season

This exercise aims at finding the minimum cost of producing 9.4 MW power, which is the in-house power demand to be met if the plant is under operation.

The captive load of power gives an additional constraint for power, namely,

\[ p_1 + p_2 + p_3 + p_4 + p_5 = 9.4 \]  

... (12)

The steam balance for the different headers remain the same, along with the machine capacity, boiler and turbine equations.

The objective function involves the cost of fuel, viz., bagasse and coal. Bagasse, having an alternative sale price of Rs.250 per tonne, is included in the total fuel cost. The private cogenerator will consider this sale price or opportunity cost of bagasse while computing the per unit cost of surplus power. The unit price of F-grade boiler coal is taken as Rs.850 per tonne.

The linear optimisation problem therefore, stands, as

minimise

\[ 850 \sum_{i=1}^{7} c f_i + 250 \sum_{i=1}^{7} f_i \]

subject to

constraints (1)' through (11) and (12) ... (M.1B)

Results:

The objective function value is Rs.17,460.75 with a total bagasse consumption of 69.84 tonnes per hour. The optimal fuel-mix involves no purchased coal in any of the boilers. The available bagasse is sufficient for steam generation for the process as well
as for generation of 9.4 MW power. A surplus of 1.89 tph of bagasse still comes out for storage. This gives the most significant fuel-advantage in the sense of self-sufficiency in fuel for the in-house power load. This implies that under the current configuration, the plant can operate by only byproduct bagasse to meet its own power requirement. However, the results in the earlier section has shown that a marginal coal-firing in addition to the available bagasse may generate exportable surplus.

Moreover, the in-plant load of 9.4 MW can be met by only the four back-pressure turbines. The optimal solution shows that the CEST can be shut down entirely. The BP-ST sets can generate 2 x 2.18 MW, 2.75 MW and 2.28 MW while their capacities are 2 x 2.5 MW, 3 MW and 2.5 MW respectively. This shows capacity utilisation for the BP-ST sets at near maximum as well. Successive iteration has further shown that one boiler (B#4) of 1 x 30 tph capacity can be shut down too.

This points out to the fact that there exists idle capacity in boilers and turbines which may be used for surplus power generation within the existing infrastructure. The in-house power load is less than what can be optimally generated with the given infrastructure.

The current operating mode of the plant is to shut down a 1 x 10 tph boiler (B#7) and the CEST. This is slightly sub-optimal as compared to the cost-minimising choice. A boiler of higher steam generation capacity can be shut down while the plant practice is not likewise. Additional steam is raised in B#4 (1 x 30 tph) which is not optimally needed to produce 9.4 MW power. This further consumes marginally more bagasse, 69.96 tph and involves slightly higher fuel cost, Rs.17,497.39. The LP-optimum thus provides a more cost-economic solution for generating 9.4 MW of electricity than the plant's current practice.
The total fuel cost per hour for the production of 15 MW power (section 6.5.1) is Rs.24562. The minimum fuel cost for the generation of 9.4 MW is Rs.17,460.75 per hour. The incremental fuel cost is Rs.7,101.25 per hour for the surplus cogenerated power of 5.6 MW, giving a fuel cost of Rs.1.26 per unit (KWH) of power.

Before going into an investigation of alternative machine configurations, the options for power generation during the off-season under the existing mode needs to be studied. However, it may be intuitively suspected at the onset to be an expensive option in view of the total coal-firing and loss of the backpressure steam at 1.5 kg/cm² with no use in the plant during off-season.

**6.5.3 The Off-Season Power Generation in the Current Mode**

During May to October, no bagasse is available and the boilers are run entirely on purchased coal. In the optimisation model, the constraint on bagasse fuel is accordingly dropped and the boiler equations (3) have only coal, i.e.,

\[ \text{bis} = \beta_i(cfi), \quad i = 1, 2, \ldots, 7 \]  \hspace{1cm} \text{... (13)}

The turbine equations remain the same with no extraction at 1.5 kg/cm² from the CEST (P4). In other words, \( p_{ext4} = 0 \).

In the steam balances also, there will be changes in the 19.34 kg/cm² and 11 kg/cm² headers. In the former, only 2.75 tph will be needed for the organic plant and there will be no demand in the milling turbines. At the 11 kg/cm² header, only 3.09 tph of steam will be required for the ancillary chemical plant and nothing for refinery, distillery and sugar plant. Accordingly, constraints (8) and (9) change to

\[ b_{4s} + b_{5s} + b_{6s} + b_{7s} + \text{prd2s} - p_{5s} - \text{prd3s} \geq 2.75 \]  \hspace{1cm} \text{... (14)}

and

\[ \text{prd3s} + \text{prd4s} \geq 3.09 \]  \hspace{1cm} \text{... (15)}

6-34
Constraints (10) no more exist as there will be no consumption in the sugar plant at 1.5 kg/cm². With the other constraints remaining the same, the linear optimisation model is one of power output maximisation only. Symbolically,

\[ \text{maximise } p_1 + p_2 + p_3 + p_4 + p_5 \]

subject to

constraints (2), (4), (5), (7), (11), (13), (14), (15).

\[ \ldots \text{(M.1C)} \]

Results:

The option of generating power during the sugar plant's off-season has pushed the fuel cost higher at Rs.26879.53. The boilers, of which four are running at near maximum consume 31.62 tonnes of coal per hour. All the turbines operate at their maxima, generating 15 MW. Accordingly, the per unit fuel cost becomes Rs.1.79. This fuel cost is much higher than that of the in-season generation, viz., Rs.1.26 per KWH. The off-season power generation has no cost component associated with process-use and therefore the entire fuel cost is due to power generation.

The back-pressure steam from the four BP-STs amount to 113.62 tph with no requirement in the process. Such a massive loss of steam therefore calls for the alternative options in terms of more use of CEST. Partial replacement of BP-ST by CEST or installation of a larger number of CEST in greenfield sugar plants will be able to operate more efficiently during off-season while in-season operation can also be manipulated by control of extraction. The fact that three boilers operate near the minimum in off-season leaves the provision for capacity expansion in the turbines so that the excess boiler capacity may be utilised, both in and off-season. However, the availability of bagasse during season has to be considered while designing the capacity.
so that there is the minimum purchase of outside fuel during season and power generation is truly cogeneration.

The existing boilers are multi-fuel in nature, runs on a high pressure cycle and therefore need not be replaced while considering the alternative configurations. The back pressure turbines, on the other hand, leads to a waste of exhaust steam during off-season. Therefore, replacement of the BP-ST sets by a relevant number of CEST may be considered. Three possible alternative combinations of back-pressure and condensing-extraction turbines for yearlong power generation have been studied for this purpose and compared in terms of the cost of cogeneration in the following sections.

6.6 AN ALTERNATIVE YEARLONG OPTION FOR COGENERATION: MODEL 2 (2-BPST & 2-CEST)

In model 2, a combination of 2 x 3 MW BP-ST and 2 x 4.5 MW CEST are considered and the power output is the same 15 MW as in the existing option. In this model option, the same seven boilers are retained. In the 42 kg/cm² header, one 4.5 MW CEST (P1) may replace the existing 2x2.5 MW BP-STs. One 3 MW BP-ST (P2) and one 4.5 MW CEST (P3) may be placed to the 32 kg/cm² header while the other 3 MW BP-ST (P4) may be set at the 19.34 kg/cm² header. This amounts to a total installed capacity of 15 MW, same as the existing one. The same ancillary plants have been considered. Chart 6.3 describes this option in terms of the steam flow.
CHART 6.3 Steam Balance Diagram for Sugar Plant Operation as per Model 2.
In the linear optimisation problem, certain changes will take place in order to accommodate the changed configuration. Here too the fuel constraints (1)' and (2) remain the same, as do the capacities of the boilers and turbines (constraints 11). However, with the changes in the number, size and type of turbines, the maxima and minima have adjusted accordingly. While the boiler equations (3) remain the same, the turbine equations (4) and (5) now represent a different combination and power output equations. Two equations refer to power generation through BP-ST while the other two reflect power generation through the CEST.

The steam balance equations at different headers also adjust with the changed turbine configuration as:

\[
\begin{align*}
    b1s + b2s & \geq p1s + prd1s + prd4s \quad \ldots (16) \\
    b3s + prd1s & \geq p2s + p3s + prd2s \quad \ldots (17) \\
    b4s + b5s + b6s + b7s + prd2s & \geq p4s + prd3s + 38.7l \quad \ldots (18) \\
    prd3s + prd4s & \geq 10.38 \quad \ldots (19)
\end{align*}
\]

where all notations have their usual meanings.

The sum of extraction, exhaust from BP-ST and the pass-out from mill turbines add up to the total exhaust steam of 138.96 tph. This modifies the steam balance (10) to the following:

\[
\begin{align*}
    pext1 + pext3 + p2s + p4s + C5 & \geq 138.96 \\
    pext1 & \leq p1s \\
    pext3 & \leq p2s \\
    C5 & = 35.96 \\
\end{align*}
\]

where all notations have their usual meanings.

Similar to the methodology adopted earlier in section 6.5, the in-season power output maximisation and fuel cost minimisation exercises have been carried out to
compute the per unit fuel cost of maximum cogeneration over the cost necessary for process-use-only. A latter exercise solves the power output maximisation problem during off-season.

6.6.1 Power Output Maximisation

The optimisation exercise is similar to that in sections 6.5.1 with the changed configuration and constraints. With four turbines for power generation, the problem here is to

\[ \text{maximise } p_1 + p_2 + p_3 + p_4 \]

subject to

\[ \text{constraints (1)' through (5), (16) through (20) and (11). } \ldots (M.2A) \]

Note that \( p_1, p_2, p_3, p_4 \) here refer to a different set of BP-ST and CEST though the same notations are used.

Results:

The same amount of power, viz., 15 MW, is available in this option too. The turbines operate at the maxima, as do the boilers except for B\#4. The only boiler using coal is B\#2 to the tune of 5.6 tph along with a bagasse consumption of 6.37 tph. The other boilers together with this consume the entire amount of available bagasse, thus maintaining the optimal use of the byproduct bagasse. The optimal fuel-mix, as obtained from the optimisation exercise, consists of full consumption of available bagasse and a marginal use of coal in one boiler. Therefore, the fuel-advantage in terms of bagasse is available here as in model 1. The in-plant steam requirement is met as in the other cases through the usual balance of extraction and backpressure.

The total fuel cost per hour during season stands at 5.58 x Rs.850 + 71.71 x Rs.250 = Rs.22669.25, lower than that in the existing mode (model 1). However, to
compute the cost of cogeneration, it remains to find out the process-use-only cost of steam and power through a cost minimisation exercise.

6.6.2 Fuel Cost Minimisation

As in section 6.5.2, the cost minimisation problem here has been solved for the generation requirement of 9.4 MW for the plant with the new turbine configuration. This implies the inclusion of constraint (12) while the others remain as described in section 6.6.1.

\[
\begin{align*}
\text{minimise} & \quad 850 \sum_{i=1}^{7} c_{fi} + 250 \sum_{i=1}^{7} f_{i} \\
\text{subject to} & \quad \text{constraints (1)' through (5), (11), (12), (16) through (20).}
\end{align*}
\]

Results:

The minimum fuel cost of generating 9.4 MW of power is Rs.18105.62 per hour, marginally higher than that in the current infrastructure (model 1). The BP-STs operate at the maximum capacities while the two CESTs generate at levels lower than the maxima. Two boilers, B#2 and B#6, also generate steam at their respective minima. This again points at the excess capacity over and above the in-plant load, and hence of cogeneration, as found in the previous model. In other words, the requirement of steam and power in the process is much less than what can be optimally generated from the boilers.

The cost of 71.7 tph bagasse and 0.2 tph of coal consumed by the seven boilers for generating 239 tph live steam and 134.46 tph exhaust steam has come out to be Rs.18105.62 per hour. Combining this with the cost of maximum power output, it can
be found that the incremental cost of generating \((15-9.4)\) MW = 5.6 MW is Rs.22669.25 - Rs.18105.62 = Rs.4563.63. This gives a unit fuel cost of Rs.0.82 per KWH which is less than the cost under the existing one (Rs.1.26 in model 1).

6.6.3 The Off-season Option for Power Generation in Model 2

During the off-season, this same configuration may be utilised with coal-firing in the boilers. The boiler equations will now be devoid of any variable for bagasse fuel, i.e.,

\[
\text{bis} = \beta_{i}(c_{f_{i}}), \quad i = 1, 2, \ldots 7
\]  \hspace{1cm} \ldots (21)

The turbine equations remain the same, i.e., of the form (4) and (5), with no extraction at 1.5 kg/cm\(^2\). Accordingly, the constraints for extraction and exhaust (20) will not be there. The other steam balance equations (18), (19) will also change to

\[
b_{4s} + b_{5s} + b_{6s} + b_{7s} + prd_{2s} \geq p_{4s} + prd_{3s} + 2.75
\]  \hspace{1cm} \ldots (22)

and

\[
prd_{3s} + prd_{4s} \geq 3.09
\]  \hspace{1cm} \ldots (23)

according to the reduced steam load at the 19.34 kg/cm\(^2\) and 11 kg/cm\(^2\) headers respectively. The rest of the constraints remain the same and there is no constraint for bagasse.

The off-season power maximisation problem thus becomes

maximise \(p_{1} + p_{2} + p_{3} + p_{4}\)

subject to

constraints (2), (4), (5), (11) (16), (17), (21), (22), (23) \hspace{1cm} \ldots (M.2C)

where the changed constraints explain the new configuration and the resulting parameters.
Results:

The capacity of 15 MW is fully generated during the off-season with the help of coal-firing. However, boilers B#4, B#5, B#6 operate at their minima, leaving idle capacity. This should not be taken as an indication for further capacity expansion. The turbine capacity is optimally used and the same is compatible with bagasse-firing in the boilers in season. This power generation capacity matches with the steam generation in the boilers during season by firing the available bagasse. Cogeneration, to be practiced in the true sense, thus limits the capacity of power generation to that level which matches with the steam generation capacity from available byproduct bagasse and marginal coal only during the crushing season. Moreover, the absence of extraction from the CESTs has increased the availability of steam for power only, thus reducing the need for total steam generation.

The fuel cost has come out to be Rs.850 x 24.87 per hour due to coal, i.e., Rs.21139.5. This gives a fuel cost of Rs.1.40 per unit of power, lower than that in off-season in model 1. The use of CEST instead of BP-ST has checked the waste of low pressure steam in model 2 over model 1.

The two backpressure turbines generate around 56.9 tph of exhaust steam at 1.5 kg/cm², which has no use in the plant. In model 1, the four BP-STs produce an exhaust steam of 110 tph during off-season. Such wastage of low-pressure steam at 1.5 kg/cm² from back pressure turbines clearly indicate the inefficiency in using BP-STs when yearlong power generation is the objective. Therefore, more use of CESTs seem to be economic since it gives the choice of controlling the extraction at low pressure according to load in-season and off-season.
A second alternative model has been studied in the next section where the number of CEST is more than that in models 1 and 2 and the number of BP-ST is less. The total power generation capacity is higher too.

6.7 A SECOND ALTERNATIVE COMBINATION: MODEL 3 (1-BPST AND 3-CEST)

While the earlier models have an installed capacity of 15 MW, this new one has 16.5 MW. Retain the same seven dual-fuel high pressure boilers of model 1. There are 3 x 4.5 MW CESTs (P1, P2, P4) and 1x3 MW BPST (P3). The three CESTs are placed with the 42 kg/cm², 32 kg/cm² and 19.34 kg/cm² headers. The sole BP-ST is also fitted to the 32 kg/cm² header. The maximum capacity of power generation now becomes 16.5 MW. The boiler and turbine operating capacity norms are maintained as before [constraints (11)].

The boiler equations (3), and fuel constraints (1)' and (2) will also remain unchanged as before.

However, the turbine equations (4) and (5) and the steam balances (6) through (10) will be different under this new option. Instead of BP-STs giving exhaust steam at 1.5 kg/cm², the CEST will have extraction at that pressure for use in the process. Accordingly, the steam balance for the 1.5 kg/cm² header will have the supply from extractions (pexti) instead of back pressure exhaust. However, the one BP-ST (P3) will continue to produce exhaust at 1.5 kg/cm².

The ancillary units are considered to be the same. Chart 6.4 describes the configuration and steam flow for model 3.
CHART 6.4 Steam Balance Diagram for Sugar Plant Operation

as per Model 3
The steam balance constraints (6) through (10) can now be rewritten for the corresponding steam headers as follows:

\[ b_{1s} + b_{2s} \geq p_{1s} + prd_{1s} + prd_{4s} \quad \ldots \quad (24) \]
\[ b_{3s} + prd_{1s} \geq p_{3s} + p_{2s} + prd_{2s} \quad \ldots \quad (25) \]
\[ b_{4s} + b_{5s} + b_{6s} + b_{7s} + prd_{2s} \geq p_{4s} + prd_{3s} + 38.7i \quad \ldots \quad (26) \]
\[ prd_{3s} + prd_{4s} \geq 10.38 \quad \ldots \quad (27) \]

\[ p_{ext1} + p_{ext4} + p_{ext2} + p_{3s} + C5 \geq 138.96 \]
\[ p_{ext1} \leq p_{1s} \]
\[ p_{ext4} \leq p_{4s} \quad \ldots \quad (28) \]
\[ p_{ext2} \leq p_{2s} \]
\[ p_{3s} = C3 \]
\[ C5 = 35.96 \]

where all notations have their usual meanings.

The turbine equations for the 3 x 4.5 MW CEST are of the form (4) while that for P3 is of the form (5).

**6.7.1 Power Output Maximisation**

Similar to the optimisation problem in section 6.5.1 and 6.6.1 here again the maximum possible output of power has been worked out, subject to the steam and power constraints as furnished earlier. The fuel availability is 71.74 tph as before, boiler equations are the same too. The turbine equations have adjusted coefficients according to the new design-mix. With four number of power turbines, the problem is to

maximise \( p_1 + p_2 + p_3 + p_4 \)

subject to

constraints (1)' through (5), (11), (24) through (28). \quad \ldots \quad (M.3A)

The turbine equations will now be four in number and capacity constraints (11) will refer to seven boilers and four turbines only.
**Results:**

The optimisation exercise gives the maximum power output of 16.5 MW, meeting the process demand for steam and power. The boilers operate at their respective near maxima except for B#4 which generates 10.75 tph. This is similar to the results obtained earlier where B#6 in model 1 and B#4 in model 2 were raising steam at less than their maxima. Moreover, here again B#1 consumes coal at a rate of 8.565 tph while the other boilers consume 71.38 tph of bagasse entirely. This gives the same fuel advantage as in the case of power maximisation under the existing infrastructure (model 1 in section 6.5.1) and that under the earlier option (model 2 in section 6.6.1). Optimal use of byproduct bagasse is still maintained with nominal coal consumption.

The total fuel cost per hour for in-season power output maximisation will now be marginally higher: Rs.250 x 71.38 + Rs.850 x 8.56 = Rs.25,125.25 i.e., an additional fuel cost of Rs.563.25 for an additional 1.5 MW of power generation, as compared to the case in section 6.5.1. Compared to section 6.6.1 too, the fuel cost is higher for generating steam for process and power turbines. However, the overall cost of power per unit can be computed only after the cost minimisation exercise is carried out.

**6.7.2 Fuel Cost Minimisation**

This optimisation problem is similar to that in sections 6.5.2 and 6.6.2 with the only difference in turbine types. This minimises the fuel cost to produce power for in-house load of 9.4 MW, both for the steam and power demand. The optimisation problem is to
minimise
\[ 850 \sum_{i=1}^{7} c_i + 250 \sum_{i=1}^{7} f_i \]

subject to

constraints (1)', (2), (3), (4), (5) and (24) through (28), and (12'), \( \ldots \) (M.3B)

where (12') is the modified form of constraint (12), i.e.,
\[ p_1 + p_2 + p_3 + p_4 = 9.4 \]
\( \ldots \) (12')

Results:

The optimal fuel-mix in generating 9.4 MW power is obtained as the full use of 71.74 tph of available bagasse and a nominal consumption of 1.48 tph of coal in B#1.

The boilers and turbines do not need to operate at their maxima to produce power at less than the installed capacity. However, the respective steam balances are met by raising a total of 163.69 tph of live steam of which 35.96 tph comes as exhaust from mill turbines and 103 tph from extraction and exhaust of power turbines.

The fuel cost at the optimum is the value of the objective function, i.e., Rs.19,197.44. Comparing this with the results in section 6.7.1, it can be inferred that an additional power generation of 7.1 (=16.5-9.4) MW involves an additional cost of Rs.5,927.81. Therefore, the fuel cost of the additional power cogeneration can be obtained as Rs.(5,927.81/7.1) per KWH = Rs.0.84 per unit.

6.7.3 The Off-season Option for Power Generation in Model 3

The same dual-fuel boilers will be fed with only coal during off-season. The bagasse fuel constraint is dropped and the boiler equations (3) have only coal fuel, i.e.,
\[ b_i = \beta_i c_i, \quad i = 1, 2, \ldots, 7 \]
\( \ldots \) (29)
The turbine equations remain the same as in section 6.7.1. However, there will be no extraction at 1.5 kg/cm² for the process. As a consequence, the constraints (28) will no more exist.

The steam balance would also adjust because there will be no demand at 11 kg/cm² in the sugar plant (centrifugal, sulphur burning, sugar drying) of an order of 6.69 tph and no demand in the mill turbines at 19.34 kg/cm² of a magnitude of 35.96 tph. These two headers will cater to the ancillary units only. The steam constraints (26) and (27) would accordingly change to

\[ b4s + b5s + b6s + b7s + prd2s \geq p4s + prd3s + 2.75 \quad \ldots (30) \]

and

\[ prd3s + prd4s \geq 3.09 \quad \ldots (31) \]

The linear programme for the off-season option under this turbine configuration is a power output maximisation subject to the steam and power balances, similar to those in sections 6.5.1 and 6.6.1 with the aforementioned changes.

maximise \( p1 + p2 + p3 + p4 \)

subject to

constraints (1)', (2), (4), (5), (11), (24), (25), (29), (30), (31). \( \ldots (M.3C) \)

Results:

The installed capacity of 16.5 MW is fully produced by coal-firing in all the boilers. The total consumption of coal is 24.88 tph, raising 114.8 tph of live steam with a steam to coal ratio of 4.61.

The optimal solution further shows no extraction at 1.5 kg/cm² from turbines and no exhaust from the mill turbines. However, a 26 tph exhaust from the BP turbine P3 could not be avoided and remains as a waste.
The fuel cost to be incurred stands at Rs. 850 \times 24.88 = Rs. 21,148, associated with the 16.5 MW power generation. This gives a per unit fuel cost of Rs. 1.28, which is lower than Rs. 1.79 under model 1 and Rs. 1.40 under model 2.

Introduction of more and more CEST seems to have reduced the wastage of pass-out low pressure steam which are evident in the back-pressure steam turbines. The 26 tph exhaust steam from the one BP-ST during off-season under model 3 still provides room for further replacement of BP-ST by CEST. The next model has therefore been developed as one with all condensing type turbines. The installed capacity is also higher, to the tune of 18 MW as compared to those under models 1 and 2 (15 MW) and model 3 (16.5 MW).

6.8 AN ALL-CEST COMBINATION: MODEL 4 (4-CEST)

In this model, 4 \times 4.5 MW condensing-extraction-type turbines have been considered, providing a total power generation capacity of 18 MW. One CEST each is installed in the 42 kg/cm² header and 19.34 kg/cm² header (P1 and P4 respectively) while 2 \times 4.5 MW CESTs (P2 and P3) are installed at the 32 kg/cm² header. The same seven boilers are however retained at their respective pressure cycles with both coal and bagasse-firing options. The ancillary plants have also been considered as in the earlier models. Chart 6.5 describes this new configuration, consisting of all CESTs.

With the same 71.74 tph bagasse availability and open choice for purchased coal, the fuel constraints (1)' and (2) remain the same in the linear optimisation problem. The capacity constraints (11) adjust according to the new configuration. Addition, deletion and adjustments of the other constraints further take place according to the modifications in the optimisation exercise as in case of models 1 through 3.
CHART 6.5 Steam Balance Diagram for Sugar Plant Operation
as per Model 4
6.8.1 Power Output Maximisation

Under this model, the steam balance equations (6) through (9), the original ones in model 1, change to

\[ b_1 s + b_2 s \geq p_1 s + p r d_1 s + p r d_4 s \] ... (32)
\[ b_3 s + p r d_1 s \geq p_2 s + p_3 s + p r d_2 s \] ... (33)
\[ b_4 s + b_5 s + b_6 s + b_7 s + p r d_2 s \geq p_4 s + p r d_3 s + 38.71 \] ... (34)
\[ p r d_3 s + p r d_4 s \geq 10.38 \] ... (35)

The original constraints (10) for extraction and exhaust of steam at 1.5 kg/cm² now change to

\[ p e x t_1 + p e x t_2 + p e x t_3 + p e x t_4 + C_5 \geq 138.96 \]
\[ p e x t_1 \leq p_1 s \]
\[ p e x t_2 \leq p_2 s \]
\[ p e x t_3 \leq p_3 s \]
\[ p e x t_4 \leq p_4 s \]
\[ C_5 = 35.96 \] ... (36)

where the notations have their usual meanings. The boiler equations (3) remain the same. However, the turbine equations (4) and (5) now reduce only to the form (4) since there is no BP-ST any more.

The linear programme to be solved thus becomes

maximise \( p_1 + p_2 + p_3 + p_4 \)

subject to

constraints (1)', (2), (3), (4), (32) through (36) and (11). ... (M.4A)

Results:

The installed capacity of 18 MW is fully generated, giving a surplus of 8.6 MW over and above the process load. All of the boilers and turbines operate at their respective maxima, except for B#1 which is marginally lower. B#2 consumes 8.6 tph
of coal instead of bagasse and B#3 consumes only 0.4 tph of coal along with 15.19 tph of bagasse. B#7 also uses 2.13 tph of coal and no bagasse, so that there is a total coal consumption of 11.13 tph. The entire available bagasse is used up. A relatively higher consumption of coal in model 4 against models 1 though 3 is explained by the higher power generation and hence a higher steam requirement. The optimal fuel-mix consists of 11.13 tph of coal and the entire 71.74 tph of available bagasse.

The total fuel cost per hour for generating 18 MW power during season is the highest under this model, viz., Rs.27388 = Rs.250 x 71.74 + Rs.850 x 11.13. However, a higher total fuel cost is associated with a higher power output. To compute the unit fuel cost of only cogeneration, it is again necessary to find out the cost of steam and power for process-use only.

6.8.2 Fuel Cost Minimisation

As in the earlier models, a similar minimisation exercise is formulated for the all-CEST combination. The constraints remain the same as in section 6.8.1 except for the inclusion of constraint (12) which arises out the power load of 9.4 MW in the plant. The linear programme thus is to

minimise

$$850 \sum_{i=1}^{7} c_i + 250 \sum_{i=1}^{7} f_i$$

subject to

constraints (1)' through (4), (11), (12), (32) through (36).

... (M.4B)

Results:

To generate power for the in-plant requirement of 9.4 MW, the turbines need not produce at their maxima, except for P1. Among the seven boilers also, B#6 and B#3
generate steam at less than their maxima. A total live steam of 169.44 tph is generated for the process and the power plant. The steam requirement at low pressure is also met adequately by the exhaust and extraction.

The optimum fuel cost for steam and power for in-plant load is Rs.20265.29. This gives the total cost for process-use-only. Comparing this with that in section 6.8.1, the differential cost can be worked out as Rs.7122.71 which corresponds to the additional power generation of 18 MW-9.4 MW = 8.6 MW. The per unit fuel cost of cogeneration thus becomes Rs.(7122.71/8.6) per KWH = Rs.0.83 per KWH. This unit cost of fuel is lower than that obtained under model 1, viz. Rs.1.26. However, this fuel cost is almost the same as those obtained in models 2 and 3. The comparability of alternative options would therefore depend on the capital cost involved with each, either as a new or a partial investment. The relative merit of the model has also to be examined in the light of the cost of power generated during the off-season, i.e., power generation throughout the year has to be judged for finding out the merit of the option.

6.8.3 The Off-season Option for Power Generation in Model 4

Similar to the power output maximisation exercises during off-season under models 1 through 3, a linear optimisation problem has been developed for this model too. While the turbine equations (4), capacity constraints (11) and coal fuel constraint (2) remain the same as in case of all models, the boiler equations (29), are devoid of any variable for bagasse-fuel-use. The steam balances at the 42 and 32 kg/cm² headers are the same as in sections 6.8.1 and 6.8.2. However, equations (34) and (35) now change to

\[ b_{4s} + b_{5s} + b_{6s} + b_{7s} + prd_{2s} \geq p_{4s} + prd_{3s} + 2.75 \]  \( \cdots (37) \)

and
\[ prd3s + prd4s \geq 3.09 \] \hspace{1cm} \text{... (38)}

since there will be no steam load at the mill turbines, at the 19.34 kg/cm\(^2\) header and no load at the sugar plant, refinery and distillery at the 11 kg/cm\(^2\) header. Moreover, there will be no demand for low pressure steam at 1.5 kg/cm\(^2\). As a result, constraint (36) will no more exist. The linear programme thus changes to

\[
\begin{align*}
\text{maximise } & \quad p1 + p2 + p3 + p4 \\
\text{subject to } & \quad \text{constraints (1)', (2), (29), (4), (11), (32), (33), (37), (38).}
\end{align*}
\] \hspace{1cm} \text{... (M.4C)}

Results:

During the off-season of the sugar plant, the entire capacity of 18 MW is generated by using coal fuel in the boilers. A total coal consumption of 24.099 tph produces 111.47 tph of live steam, less than the maximum steam capacity. However, the turbines operate at their maxima with no extraction at 1.5 kg/cm\(^2\). This model has resulted in no wastage of low pressure steam during off-season, giving a definite advantage over the others. Excess boiler capacity does not indicate the scope for expansion of power generation because this boiler capacity matches with the configuration in-season. Infinite expansion of steam capacity by firing any amount of purchased fuel during off-season makes it an usual thermal power plant and it is not compatible with a cogeneration plant during the cane-crushing season.

The fuel cost of generating 18 MW of power is Rs.20484.15, giving a unit cost of Rs.1.14, which is the lowest among all the four off-season options.

In the light of the results of the above optimisation exercises, the four models may be compared in terms of fuel cost during the cane-crushing season as well as during off-season. The existing model has worked out to be the most expensive both during season
and off-season. Models 2 through 4 reveal almost similar fuel costs in the range of 82 to 84 paise/KWH during season. Use of BP-ST and CEST during season does not have differential impact on energy-efficiency because steam extraction at the stipulated low pressure from CEST and at back pressure from BP-ST are similar. However, a relatively larger consumption of coal in model 1 (8.56 tph for 15 MW power) compared to model 2 (5.6 tph for 15 MW), model 3 (8.5 tph for 16.5 MW) and model 4 (11.13 tph for 18 MW) has given a relatively higher fuel cost in model 1. The available bagasse has been entirely consumed in all the models. The fuel costs during off-season vary widely over the options. The BP-STs cause wastage of low pressure steam during off-season because of the absence of in-plant demand. This is avoided in the CEST by allowing condensation instead of extraction at the stipulated low pressure. Increase in the number of CESTs reduces the fuel cost during off-season. The off-season fuel cost of Rs.1.79/KWH in model 1 reduces to Rs.1.140/KWH in model 2, to Rs.1.28/KWH in model 3 and to Rs.1.14/KWH in model 4. Use of CEST has revealed energy-efficiency improvement over BP-ST during off-season. The fuel cost figures for both season and off-season under the alternative models have been presented in table 6.4 along with other components of cost.

However, the overall comparability of the four model options depend not only on fuel cost but also on the investment involved. Partial replacement of machinery in the brownfield plants and total investment for greenfield sugar plants would also compare differently among each other. Only after the inclusion of capital cost, fixed and working, and other operating expenditures, the four models can be truly compared and ranked in terms of merit. The supply prices of cogenerated power under the alternative model options can be computed as the sum of the fuel cost, fixed and working capital cost and
other operating expenditures. The final supply prices would vary from season to off-
season and from greenfield to brownfield plants. The following section develops the
capital cost calculation, both as new investment in greenfield plants and partial
replacement in brownfield plants.

6.9 CAPITAL COST FOR GREENFIELD AND BROWNFIELD OPTIONS

In the earlier sections of this chapter, optimisation exercises have been carried out
to compute the per unit fuel cost of cogenerated power under the four alternative model
options. Capital costs have been calculated in this section for arriving at the respective
total costs of cogenerated power. The method of calculating capital is similar to that
adopted in Chapter IV.

Under each model option, two cases have been considered accordingly for
greenfield and brownfield plants. Capital investment for greenfield plants mean the cost
of installing the entire capacity, including those of boilers and turbines. On the other
hand, the brownfield options will mean investment for partial replacement of the
machinery over the existing ones. Since the same seven multifuel boilers of the existing
configuration are retained in all the models, brownfield plants would involve investment
in replacing turbines only. Model 1 assumes four BP-ST and one CEST. Therefore,
partial replacement under model 2 (two BP-ST and two CEST) involves cost of 1 x 3
MW BP-ST and 1 x 4.5 MW CEST, giving a 7.5 MW capacity installed through new
turbines. The alternative combination of BP-ST and CEST has still given the same total
capacity of 15 MW. Similarly, two additional CESTs in model 3 (one BP-ST and three
CEST) involves the installation cost of 2 x 4.5 MW turbines. Three additional CESTs
in model 4 (four CESTs) imply an additional 13.5 MW capacity, the cost of which has
to be incurred. The capital cost calculations have been based on these investments for
brownfield plants. However, those for the greenfield plants mean installation cost of the entire capacity. The calculations refer to the fixed capital servicing charges towards these investments. The cost of working capital has to be calculated separately as proportions of the variable works cost.

The cost of fixed capital services has been computed as capital investment amortised over the life time of the power plant of 15 to 20 years. A 16 percent rate of return with a debt-equity ratio of 1:1 has been considered as the opportunity cost of capital, as in the power sector of India. The gestation lag is taken as 3 years and the salvage value realizable in the last year of the plant life is 5 percent of the total investment. Investment is phased as 20 percent, 30 percent and 40 percent in the first three years and 5 percent in the eighth year of production. A further 5 percent investment in the fourteenth year extends the plant life to 20 years. The generation of power output is phased as 70 percent, 90 percent and 100 percent, starting from the fourth year. The installation cost of the power plant in sugar industry is around Rs.3 cr/MW (BHEL), on an average, including both the costs of boilers and turbines. The cost of BP-ST is around Rs.0.5 cr/MW and that of the CEST is approximately Rs.0.75 cr/MW. The cost of high pressure 40 tph spreader stoker boilers are around Rs.2 crores (BHEL).

The method of calculating the working capital cost is similar to that adopted in chapter IV. The interest rate on working capital has been considered as 16 percent. Since the variable works costs vary from season to off-season, the variable cost-related working capital will vary accordingly. However, working capital cost does not vary with greenfield and brownfield options while the fixed capital servicing charges do not vary.
with season. The total capital cost will vary with both season and option, since it is a sum of the working capital and fixed capital servicing charges.

The other elements of cost include those of repair and maintenance at the rate 2.5 percent of the total project cost and another 2.5 percent as salary, wages and administration for cogeneration.

The final supply prices of cogenerated power will be the sum of these components. This will vary according to season and options across greenfield and brownfield. Table 6.4 summarises the cost components and final supply prices.

In model 1, for existing plants, there is no capital investment involved since it is the existing machine configuration. In that case, it is only the fuel cost, working capital cost, operations and maintenance cost and administrative cost which would dictate the supply price of power. However, if the same BPST-CEST combination is considered for a newly coming up sugar plant with 15 MW capacity, then a fixed capital servicing charge is to be considered for the capital investment. The total capital cost of model 1 becomes Rs.0.82/KWH and Rs.0.86/KWH for greenfield plants, during season and off-season respectively. For brownfield plants, only the working capital charge will be there in this model.
Table 6.4 Cost of Cogenerated Power Under Alternative Options in a Typical 5000 TCD Sugar Plant

<table>
<thead>
<tr>
<th>Unit</th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Export of Power MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Season</td>
<td>5.6</td>
<td>5.6</td>
<td>7.1</td>
<td>8.6</td>
</tr>
<tr>
<td>- Off-season</td>
<td>15.0</td>
<td>15.0</td>
<td>16.5</td>
<td>18.0</td>
</tr>
<tr>
<td>2. Fuel cost Rs/KWH</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Season</td>
<td>1.26</td>
<td>0.82</td>
<td>0.84</td>
<td>0.83</td>
</tr>
<tr>
<td>- Off-season</td>
<td>1.79</td>
<td>1.40</td>
<td>1.28</td>
<td>1.14</td>
</tr>
<tr>
<td>3. Total Capital Cost* Rs/KWH</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Season</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Greenfield</td>
<td>0.82</td>
<td>0.83</td>
<td>0.84</td>
<td>0.86</td>
</tr>
<tr>
<td>ii) Brownfield</td>
<td>0.10</td>
<td>0.42</td>
<td>0.54</td>
<td>0.55</td>
</tr>
<tr>
<td>(b) Off-season</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Greenfield</td>
<td>0.86</td>
<td>0.88</td>
<td>0.88</td>
<td>0.89</td>
</tr>
<tr>
<td>ii) Brownfield</td>
<td>0.14</td>
<td>0.47</td>
<td>0.58</td>
<td>0.58</td>
</tr>
<tr>
<td>4. Other Operating Cost** Rs/KWH</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Greenfield</td>
<td>0.036</td>
<td>0.036</td>
<td>0.039</td>
<td>0.040</td>
</tr>
<tr>
<td>ii) Brownfield</td>
<td>0.010</td>
<td>0.018</td>
<td>0.024</td>
<td>0.024</td>
</tr>
<tr>
<td>5. Total Cost Rs/KWH</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Season</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Greenfield</td>
<td>2.11</td>
<td>1.68</td>
<td>1.71</td>
<td>1.73</td>
</tr>
<tr>
<td>ii) Brownfield</td>
<td>1.37</td>
<td>1.26</td>
<td>1.41</td>
<td>1.42</td>
</tr>
<tr>
<td>(b) Off-season</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Greenfield</td>
<td>2.68</td>
<td>2.38</td>
<td>2.19</td>
<td>2.07</td>
</tr>
<tr>
<td>ii) Brownfield</td>
<td>1.94</td>
<td>1.89</td>
<td>1.88</td>
<td>1.75</td>
</tr>
</tbody>
</table>

* Total capital cost includes fixed and working capital charges.

** Operating cost includes those of repair, maintenance, salary and wages and administrative costs.

All figures are based on mid-1995 prices.
However, for the other models 2, 3, 4, brownfield options involve partial replacement and hence both fixed and working capital charges. The total capital costs for model 2 are Rs.0.85/KWH and Rs.0.88/KWH in season and off-season for greenfield plants. The same for brownfield plants are lower for obvious reasons, viz., Rs.0.42/KWH and Rs.0.47/KWH respectively. For greenfield plants under model 3, capital cost figures are Rs.0.84/KWH and Rs.0.88/KWH for in-season and off-season while those for brownfield options are Rs.0.54/KWH and Rs.0.58/KWH respectively. The capital cost for greenfield plants under model 4 vary from Rs.0.86/KWH to Rs.0.89/KWH over season and the same for brownfield plants are Rs.0.55/KWH and Rs.0.58/KWH. The capital cost figures are all presented in table 6.4 as components of the total cost of cogenerated power. Under all the models, capital costs are higher for greenfield plants than the brownfield ones during both season and off-season. This is intuitively obvious because brownfield options involve partial replacement of machinery and greenfield options involve partial replacement of machinery and greenfield options imply the total installation. On the other hand, off-season total capital costs are higher than those in season because of the higher working capital component. Working capital charges have been higher due to the higher variable fuel cost during off-season than in-season. However, the margin of working capital differential and hence total capital charge differential is only around 3 to 5 paise per unit.

Table 6.4 presents the total cost of cogenerated power under the four models as the sum of fuel cost, capital charges and other operating costs for both greenfield and brownfield options during the cane crushing season and off-season.
6.10 A COST COMPARISON OF ALTERNATIVE OPTIONS

The four model options have shown substantial potential for cogenerating exportable surplus power. A typical 5000 TCD sugar plant has revealed a cogeneration potential as high as 18 MW, almost double its in-plant requirement. This gives a surplus of 8.6 MW in season. The entire amount is available during off-season if alternative fuel is used (model 4). The other models have also shown exportable surplus of 5.6 MW to 7.1 MW during season and 15 MW to 16.5 MW during off-season. Blown up for the entire industry, this may offer a substantial amount of power to the country during its season (winter) and off-season (peak summer).

To what extent will this additional power supply be attractive to India's power sector would depend on the supply price of the sugar plants vis-a-vis the utility's offer. The results obtained in the exercises here show that the per unit cost of cogenerated power varies between Rs.1.68 and Rs.2.11 for greenfield plants and between Rs.1.26 and Rs.1.42 for brownfield plants during season. Model 2 has appeared to be the cheapest in season. Models 3 and 4 have recorded high costs due to higher capital costs in installing CEST in a larger number. This has off-set the saving in fuel cost due to the energy-efficiency of CEST over BP-ST. Similar ranking between models 2, 3 and 4 hold for greenfield and brownfield plants. However, model 1 in season has revealed interesting results for old and new plants. While the existing plants offer a cheap rate of Rs.1.37/KWH, a greenfield establishment has worked out to be the costliest at Rs.2.11/KWH. A new establishment with four BP-STs and only one CEST does not offer energy-efficiency and hence a cheap rate of cogenerated power.

Higher energy-efficiency of CEST is clearly revealed in their off-season fuel costs. Gradually increasing numbers of CEST in models 2, 3, 4 have brought in saving.
in fuel cost to such an extent as to offset the higher capital costs for both greenfield and brownfield plants. Model 4 has appeared to be the best option during off-season, followed by models 3, 2, 1 for both options. Avoidance of back-pressure steam in BP-STs explain the superiority of options with larger number of CESTs. The total per unit cost of power during off-season varies between Rs.2.07 and Rs.2.68 for greenfield plants and between Rs.1.75 and Rs.1.94 for brownfield plants. Total coal firing in the boilers has made off-season power relatively costly. Moreover, the off-season operation cannot be termed as cogeneration since there is no process-use of steam/heat. It simply utilises the available infrastructure with alternative fuel.

A merit ranking of the four models for alternative options and seasons have been presented in table 6.5.

**Table-6.5: Merit Ordering of the Alternative Options**

<table>
<thead>
<tr>
<th></th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
<th>Model 4</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>1. Season</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Greenfield</td>
<td>4</td>
<td>1</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>(b) Brownfield</td>
<td>2</td>
<td>1</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
<td><strong>2. Off-season</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Greenfield</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>(b) Brownfield</td>
<td>4</td>
<td>3</td>
<td>2</td>
<td>1</td>
</tr>
</tbody>
</table>

Note: Ranking is in an ascending order.

Because of the shifting ranks of the models over season, no unique ranking is possible for the whole year. While the existing model 1 offers moderately cheap power in season, it is not cost-economic for greenfield plants or for off-season operation with the existing machinery. Model 2 offers cheapest cogenerated power during season with an equal number of BP-ST and CEST thus balancing the lower fuel cost and higher capital cost. However, models 3 and 4 generate cheaper power during off-season.
To sum up, it may be pointed out that a typical sugar plant has substantial potential for cogenerating exportable surplus. It has been observed that the brownfield plants offer cheaper rates of power than the greenfield ones during both season and off-season. It may be concluded that the existing plants may be upgraded by necessary replacement of machinery for providing cheaper power rather than establishing new cogeneration plants. Cogeneration for in-plant load is already an existing practice, which may be improved further. Moreover, setting up new plants depends on many factors other than cogeneration. The brownfield plants may be efficiently operated with necessary upgradations in the machinery and bring in cost-economy due to better fuel-efficiency. The optimal mixes of bagasse and supplementary coal, as obtained in the optimisation exercises of this chapter, brings in the saving in fuel cost, thus, generating cheap power.

The off-season costs of power generation are higher for obvious reasons. The system is not cogeneration any more and operates as coal-thermal power generation stations. The off-season rates of Rs.1.75/KWH to Rs.1.94/KWH for brownfield plants still offer cheaper rates than the industrial tariff of Rs.2.11/KWH charged by the utility. Model 4 under greenfield option can still compete with the utility's rate because its cost is Rs.2.07/KWH. However, the other three models would incur higher costs as greenfield options. This can be explained by the wastage of backpressure steam in BPSTs which is not justified for coal-based power generation without any process load for steam. Only model 4 may be considered for off-season power generation at costs comparable to other generators.

Therefore, to conclude, it may be said that all the models offer cheap cogenerated power during season. Among them, brownfield plants offer cheaper rates than the
greenfield ones. Moreover, they offer cheap off-season rates in brownfield plants only while an all-CEST combination (model 4) gives cheap rate even as a greenfield option. In view of the margin in the cogenerator's cost vis-a-vis the sale price obtained from the grid and/or a third party, the decision to take up cogeneration schemes may be justified. The additional profit motive is the economic rationale to venture into cogeneration projects by optimally utilising the capacity and exploiting the potential. In view of the government of India's offer of Rs.2.25/KWH in 1995, the results obtained in this chapter seem to be attractive, justifying cogeneration in sugar plants.

It may be mentioned that the results of the various optimisation exercises have the bases unchanged for ±20 percent variation in fuel prices. This keeps the optimal solution values of power unchanged while, fuel costs of different model options will be augmented/decreased accordingly. However, the relative merit ranking remains unchanged despite the higher/lower costs and hence the supply prices.

6.11 OTHER ENERGY CONSERVATION MEASURES*

Apart from the distinct scope of bagasse-based cogeneration of power, the sugar industry has other areas of further energy conservation too. The industry suggests new techniques of energy conservation as stated below:

(a) There is a possibility of reducing the steam requirement per ton of sugar from 55 percent cane to 41 percent cane by minimising steam consumption in boiling houses, evaporation stations, pans, juice heaters etc. and process loss.

(b) The net surplus bagasse yield can be improved by using pressurised feedwater tank in the boilers which raises the feedwater temperature at suction feed pump. This can give around 1 percent saving of mill wet bagasse.

* This section is based on the report on Technology in Indian Sugar Industry prepared by TIFAC, DST, GOI, 1991.
(c) The flue gas of the bagasse boiler can be used instead of air heater to heat the ambient air to dry mill wet bagasse. This gives 10 percent saving of bagasse. This technique of continuous bagasse drying improves the net calorific value of it by reducing the moisture content and thus there is a greater heat transfer for high pressure steam.

(d) Use of natural gas with high calorific value in bagasse/multifuel boilers has also been considered as an alternative option. This may be attractive to the sugar factories with gas lines in the vicinity. The same boilers with/without minor modifications can be used thus incurring low capital cost. The option of going back to bagasse will still be there.

6.12 SUMMARY

The sugar industry provides one of the most easily exploitable source of energy at attractive prices. The existing power plants installed in the sugar factories have high potential of bagasse-based cogeneration of electricity even after fulfilling the process load. Use of high-efficiency turbo-generator sets and high pressure boilers may give substantial long term financial benefits. Initial capital investment in replacement of low-efficiency machinery or in setting up new plants with cogeneration may result in a huge generation of exportable power. In-season export may cater to the peak agricultural power demand while the off-season generation can entirely be used to meet the peak summer load at attractive prices. The results obtained in this chapter has revealed the potential for cogenerating exportable surplus power during season at rates lower than the tariff charged by the utility. The same infrastructures have been shown to be operative during off-season too. The existing plants with necessary replacements in machinery can also offer power during off-season at rates comparable to the grid's. The optimal use of byproduct bagasse and supplementary coal has given attractive supply prices under alternative machine configurations. A 5000 TCD plant has been found to cogenerate as much as 18 MW while its in-plant load is not more than 9.4 MW. Blown up for the macro-economy, the total surplus power generation potential of the sugar industry by the
end of the eighth plan has been estimated at 3200 MW (approx.) from the total cane likely to be crushed per annum @ 1378.8 lakh tonnes in 396 plants with an average capacity of 2325 TCD (NFCSF, 1994). This figure broadly matches with those obtainable from the current analysis. Although the exact details of plant and machinery for each sugar plant is not available for studying brownfield plants and all the greenfield plants need not follow a single model option, one may broadly estimate the potential of the entire sugar industry. The surplus potential of cogenerated power for sale during the crushing season varies from 1023.4 MW to 1571.6 MW for the respective models. The off-season potentials vary from 2741.2 MW to 3289.4 MW respectively. The off-season potentials for power generation not only provide the saleable quantities but also reflect the maximum installable capacity of the 396 sugar plants in the country. The necessary policy guidelines, pricing rules, negotiations with the utility, financial concessions and other institutional support needs a coordinated approach in order to make this potential a commercially viable venture. Such issues are discussed in the next chapter along with the possible problems generally encountered in implementing cogeneration.