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AN ENERGY COST OPTIMIZATION METHOD FOR A LARGE SCALE HYBRID CENTRAL COOLING PLANT WITH MULTIPLE ENERGY SOURCES UNDER A COMPLEX ELECTRICITY COST STRUCTURE

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The cooling energy cost could be a significant portion of the total energy cost for a large organization or building complex during summer. A hybrid system or thermal energy storage system is usually applied to reduce the energy cost. However, without proper integration and operation, the advantage of using such systems could be limited.

This study presents a general energy cost optimization methodology and mathematical model for a hybrid cooling system under a complex electricity cost structure. The model considers the efficiency of the hybrid cooling system and multiple energy sources. The energy cost evaluation reflects a complex cost structure including electrical energy cost, electrical demand cost, electrical ratchet cost, fuel cost, and electrical energy consumption from other facilities.

The optimization model is constructed as a mixed integer nonlinear program. To reduce high computational intensity, a dual-stage solution method is used by introducing a decision variable of the electrical demand limit as a constraint. This reduced computation provides the possibility of the real time implementation of the model for practical

purposes. This study also shows how the optimization model can be used with a simple cooling load forecasting strategy to avoid a high electricity cost.

A case study of the central cooling system in an academic institution shows that the developed methodology and model can be used to reduce around $150,000 in energy cost per year. In particular, the case study shows that the developed optimization model can significantly reduce the high demand punitive costs that are hard to reduce in the current manual operation based on operator experiences. In the case study, this reduction is possible by properly shifting part of the cooling load from electric chillers to steam turbine chillers during peak electrical demand season and thus decreasing the peak electricity consumption under the complex demand charge structure.

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CHAPTER 1

INTRODUCTION

1.1 Background

Energy cost for building cooling can be a significant portion of the energy cost for a large organization or building complex. For example, the University of Nebraska-Lincoln paid approximately $6,300,000 for electricity for one year period [1], and more than $1,200,000 of it was for the building cooling.

A significant portion of the cooling energy cost often does not come from the direct electrical energy charge but electrical demand charge. The aforementioned academic institution actually paid more for electrical demand cost than for electrical energy cost in August 2010 [1]. Due to the non-efficient operation of cooling plant in August 2010, it also paid about $279,000 as an electrical demand charge in additional to the charge for the actual use in the winter season of the same year under the current electrical demand ratchet policy [1].

The reason of the high demand cost is the high peak electrical power used in the summer season to produce chilled water to meet the high cooling load. The electrical demand from the cooling system could contribute up to 35% of the total peak electrical demand in summer months [1]. At the same time, the high peak electrical demand in the summer season would set the high peak electrical ratchet for the winter season. As the electrical ratchet goes higher, more additional meaningless demand charge would occur. Therefore, it could be beneficial for such an organization to reduce the peak electrical demand in the summer and save unnecessary cost, through a proper operation of the hybrid central cooling plant.

Reducing the peak demand also helps electricity suppliers. The considerable variation of the electrical demand caused by the significant difference of cooling load between peak and off-peak cooling demand periods can not only severely affect the electricity suppliers' production investment and operation, but also greatly increases the burden of the entire electrical power grid. Thus, the high peak demand ultimately raises the cost of electricity production, and the energy purchase rate for other users in the entire grid system. It is therefore economically beneficial to reduce the peak electrical demand for the community.

The reduction of the peak electrical demand and overall energy cost is, however, a challenging problem. To reduce the peak electrical demand, part of the cooling load is usually shifted from electric chillers to steam turbine chillers (or to a thermal energy storage system). Integrating these two kinds of chiller systems of different energy types is more challenging than integrating a multi-chiller system of a single energy type. First, although the steam turbine chiller enables load shifting to reduce the peak electrical demand, electric chillers are usually operated more than necessary because the unit fuel cost for operating steam turbine chillers is usually higher than the unit electrical energy cost for operating electric chillers. Thus, the advantage of using the steam turbine chillers is often not fully utilized. Second, when a complex electricity cost structure or policy is applied, it could be difficult to evaluate the trade-offs between the fuel and electricity cost on the hourly basis or even daily basis. Third, the uncertainty of cooling demand and the nonlinear cost structure, especially electrical demand charge and electrical demand ratchet policy, makes the optimal operation difficult to determine.

1.2 Research Objectives and Contributions

The objective of this research is to reduce the energy cost by modeling, integration and control of the chiller systems that use dual energy sources. An operation schedule for each chiller in the hybrid multi-chiller cooling system is generated by this energy cost optimization model, using simple cooling load prediction.

The academic contribution of this research is the development of a general methodology and mathematical model that explicitly integrates the hybrid cooling system under a complex electricity cost structure. Although this research focuses on a hybrid cooling system, the methodologies can also be extended to a wide range of cooling systems that use multi-source energy or single source but with a thermal energy storage system.

The practical contribution of this research is the development of a practical energy cost optimization model incorporating cooling load forecasting and an efficiency model of a chiller system for real time implementation. The case study of the cooling plant at the University of Nebraska-Lincoln City Campus shows a potential saving of approximately $150,000 per year.

This thesis is structured as follows. In Chapter 2, a literature review of the current existing research is presented. The mathematical model is described in Chapter 3. The structure of this research, cost model, plant model, and optimal operation planning model are discussed in detail in this chapter. A case study is shown in Chapter 4. Conclusions and future research directions are shown in Chapter 5.

CHAPTER 2

LITERATURE REVIEW

The optimal control of the cooling system is usually referred to the energy optimization problem or cost optimization problem of the cooling system. The optimal control problem can be classified into two categories depending on the focus – local control and global (supervisory) control [2].

2.1 Local Control

Local control focuses only on the optimal control of chillers through the efficiency analysis, rather than the entire cooling system. Y.C. Chang et al. [3] introduced an optimal chiller sequencing model by branch and bound method to achieve the best performance of a multiple chiller cooling system. However, their result showed a slight energy reduction compared with the maximal peak coefficient of performance method. K.T. Chan et al. [4] proposed a part load efficiency model to optimize the performance of chillers in a cooling plant where an array of air-cooled chillers of the same type was installed. The optimal range of part load ratio was generated when different numbers of chillers were in operation. In their work, they also compared the different weather-load profiles of offices and hotels. Their result also indicated different strategies should be implemented on office and hotel buildings.

Although the chiller plant with multiple chillers of the same type provides benefit and convenience in management and maintenance, more chiller plants are usually equipped with chillers of different capacities, because it could provide more operational flexibility and standby capacity from a chiller plant with an array of the same type of chillers.

2.2 Global Control

Previous studies [2] indicated that local controllers may not be energy-efficient or cost-effective, compared with global controllers when the whole system is taken into consideration. Thus the efficiency analysis of the entire cooling system is necessary and important.

The global control mainly focuses on the optimization through the efficiency analysis of the entire cooling system. By modeling the efficiency of the whole cooling system, it becomes possible that the entire system is operated at the best cost efficient level. Therefore improving efficiency and eventually saving cost is achievable by a higher operation level decision, especially when a complex electricity cost rate is applied.

Different methods of modeling have been studied in this field. L. Lu et al. [5, 6] presented a model-based global optimization model for an overall analysis of the HVAC system. The influence of the outdoor temperature was taken into consideration. T.T. Chow et al. [7] developed a global optimization model through genetic algorithm and neural network. S. Wang et al. [8] introduced an online supervisory control model to achieve the lowest energy cost of a central cooling system. K.F. Fond et al. [9] presented an evolutionary programming optimization model to manage the energy of a HVAC system. Later, they developed an optimization model for energy management by using evolutionary algorithm from the evolutionary programming optimization model they proposed previously [10]. Y. Yao et al. [11] introduced an empirical model for optimal operation of a large cooling system for residential building. Instead of using a traditional coefficient of performance model, they introduced a system coefficient of performance to study the mechanism of the cooling system. H. Zhang et al. [12] explored an optimization model through decentralized nonlinear adaptive control method for an HVAC system.

However, when a complex cost structure (for example, time-of-use differentiated rate, multiple electrical energy sources and demand ratchet policy) is applied or multi-energy types (for example, electricity and fuel, or electricity and thermal energy storage system) are in use, the coefficient of performance model of a chiller system does not always guarantee the minimum energy cost over the entire time horizon of a billing period (usually a calendar month). J. Xu et al. [13] proposed an optimization-based approach to optimize the total operation cost in a cooling system with direct digital control system. The total energy cost consisted of electrical energy cost, monthly electrical demand cost, and 11 months electrical demand/ratchet cost. Instead of optimizing the cost throughout the overall billing period, they tried to minimize the daily cost by scaling the monthly peak demand rate and 11-month peak demand rate to a daily rate. They used multilayer perception neural network to study the mechanism of the cooling system. In order to solve the multistage optimization problem, they applied the Lagrangian relaxation method, and also introduced two variables of the expected peak demands of the current month and of the following 11 months.

2.3 Global Control with Time-of-Use Differentiated Cost Rate

There are two common methods introduced in the literature [2] to reduce the total operation cost when a time-of-use differentiated electrical cost rate or an even more complex cost structure, for example demand ratchet is applied. Significant saving can be achieved by properly implementing these two methods.

The first method, which has been popular in the last decade, is the thermal storage system. Extensive research has been conducted on the topic based on different conditions.

Some of researches were studied under a deterministic case of cooling load. For instance, J. Zhou et al. [14] developed an on-off chiller controller for a campus cooling system with thermal energy storage system to minimize the operation cost under a complicated time-of-use electricity rate schedule. Their optimization model was examined through three different scenarios. However, in their model, only the time-of-use differentiated energy rate was considered. D.D. Massic [15] developed a neural network-based controller to optimize the operation cost of a cooling system with thermal energy storage system. In the model, both time-of-use differentiated energy rate and demand rate were considered. At the same time, the electrical demand from non-cooling purpose was also considered when the demand cost was calculated.

Some of other researches took the predictive control characteristic into consideration. For example, G.P. Henze et al. [16] described a model-based predictive control model for active and passive building thermal storage inventory to save the energy cost under a time-of-use differentiated cost rate. Y. Ma et al. [17] proposed a mixed integer nonlinear program to realize a model-based predictive control model of a building cooling system with thermal energy storage system. By considering both the efficiency performance of the cooling systems and the upper and lower bound of the campus (UC Merced Campus) load in record, they tried to optimize the electrical energy cost through the real time implementation of the model-based predictive control model. In order to reduce the calculation capacity required by the mix integer nonlinear program problem, they introduced a dual stage optimization strategy to solve the problem. By choosing the tank operation mode profile in the first stage, the problem in the second stage was recast to a nonlinear program problem.

The last group of the researchers tried to focus on the dynamic property of the problem. R.H. Henze et al. [18] introduced a predictive optimal controller model for a cooling system with thermal energy storage system. They developed a dynamic programming model to optimize the operation cost over a planning horizon of 24 hours. In order to optimize the cost, they also considered the performance of the cooling system, the dynamics of the energy rate, and the load forecasting. In their work, they compared the impact from the different levels of the knowledge about the cooling system performance. They also evaluated three different conventional control strategies. J.E. Braun [19] described a dynamic optimization model to reduce the operation cost. In his work, he compared three models with different electrical energy cost structures – minimum energy costs without time-of-use rates, minimum energy costs with time-of-use rates, and minimizing peak electrical demands. T. Nagii [20] introduced a method to minimize annual energy, peak energy demand, and annual energy cost by using a building thermal storage. To solve this multi-objective optimization problem, he used both dynamic programming and Pareto solution method.

Although there are several researches related to the thermal energy storage system, there are only limited studies on the second method -- applying a hybrid cooling system. A.R.

Musgrove et al. [21] developed a linear programming optimal control model to minimize the energy cost of the cooling system that has electric, steam-driven and absorption chillers. However, they did not consider the electrical demand cost and maintenance cost in their study. G.L. Gibson [22] introduced a supervisory control model for a hybrid cooling system where there were an electric chiller and a gas-fired, engine-driven chiller. A neural network model was developed to study the performance of the cooling system, and a genetic algorithm was developed for optimal scheduling. M.W. Ellis et al. [23] developed an optimization model considering life-cycle cost of a hybrid cooling plant. Installation, energy, demand and maintenance costs were considered in their model. However, the auxiliary equipment, such as pump and cooling towers were not considered. J.E. Braun [24] introduced near-optimal control strategies under an electrical demand constraint based on a chiller sequencing model for a hybrid cooling plant. Both time-of-use differentiated energy cost and demand cost were considered in his work. He proposed a chiller sequencing strategy considering the coefficient of performance of four different types of chiller. He also compared the result from the sequencing strategies with or without part-load control under different electrical demand limits.

2.4 Cooling Load Forecasting Used in Optimal Control

Another important aspect in the cost optimization of a cooling system is the cooling load forecasting. Because the operation of any cooling system is ultimately determined by the cooling demand which is affected ambient weather conditions, building occupancy, indoor activity and other factors, the optimal operation planning is achievable only when the cooling demand forecasting is accurate enough. More cost may occur with the decrease of the forecasting accuracy. However, many optimization models in the literature were examined under the prefect information of cooling loads.

The current existing research focused more on the short-term cooling demand forecasting, due to the difficulty to achieve high accuracy in mid-term or long-term forecasting. Typically a 24-hour or 48-hour planning horizon was usually used in predictive control model in the literature for a short term scheduling, because a long-term cooling load forecasting with high accuracy is usually impossible due to the uncertainty. Because of this limit, the electrical demand cost and electrical ratchet cost was calculated based on a daily rate which was scaled from the monthly rate.

However, a longer horizon, one week and month, may be necessary for mid-term and long-term scheduling, if other factors are taken into consideration. For instance, complex electricity cost structure and dynamic fuel prices are considered. Although the monthly electrical demand rate can be scaled to daily rate, it is obviously that the "cost optimization operation" obtained through this method may not be optimal. By focusing on the daily cost, the information and the overall mechanism of the entire month' cooling load profile, cooling system's operation and energy cost are concealed.

On the other hand, different forecasting models have different advantages and disadvantages. One simple method cannot achieve a high accurate forecasting result through the entire planning horizon. By comparing these models, a more sophisticated method could be developed, which combines several models together. Each model will be used to forecast the cooling demand during a specific time period based on it characteristic, so that it can overcome the disadvantage of other models.

Y. Ma et al. [17] used a straightforward method to predict the cooling load. By analyzing the previous cooling load profile, they established the upper and lower bounds of the cooling load, and used that for daily operation scheduling. It is obvious that although this straightforward method buffers the impact of demand uncertainty, the result cannot be considered as optimal.

One of the traditional methods of cooling load prediction is to establish a regression relation between weather parameters and cooling load. K.T. Chan et al. [4] analyzed the cooling load profile against different weather parameter – outdoor temperature, and the product of outdoor temperature and specific humidity. Their result showed there was significant difference between the profile of office and hotel buildings. However, the main problem of this method is there are always other factors, other than weather condition, affecting the cooling load. It is hard to include all the factors into a regression model, because of the availability and measurability of these parameters.

G.P. Henze et al. [18] compared four different load prediction models: unbiased random walk model, bin predictor model, harmonic predictor model and autoregressive network predictor model. They found the bin predictor model gave the best prediction among the four models, and they used the bin predictor model in their future work [16].

Because of the self-learning and self-calibrating ability in nonlinear problems, the neural network was often used for cooling load forecasting. However, an important input to a neural network, the building occupancy is usually difficult to measure. In work of J. Xu et al. [13], the cooling load was divided into two parts: thermal load that usually originated from lighting and other heat generating equipment, and uncontrollable load that is usually related to outside weather condition, such as building occupancy, time, day, and season. The uncontrollable load is predicted through a multilayer perception neural network.

CHAPTER 3

MODEL

This section presents the structure of the methodology, assumptions, the energy cost model, cooling plant model, cooling load forecasting and cost-optimized operation planning model used in this research.

3.1 Structure of the Methodology

The Figure 3.1 shows the structure of the energy cost optimization operation methodology. In the real time implementation, the cooling plant model will be built based on the plant structure and the data base of operation parameters. Weather condition could be included if consideration of its influence is necessary. Based on the data base of the weather condition and cooling load profile, the cooling load forecasting model will be established and updated as the data base increases. By using the weather forecast from the weather station, the cooling load of the planning horizon is generated. By structuring the cost function, the cost-optimized operation planner will provide the operation decision for the lowest cost, based on the forecasted cooling load and plant model. Operation adjustment will be made after cost-optimized operation decision is generated according to the actual cooling load and the experience of human operators. The actual operation will in the end be recorded in the data base for future use.

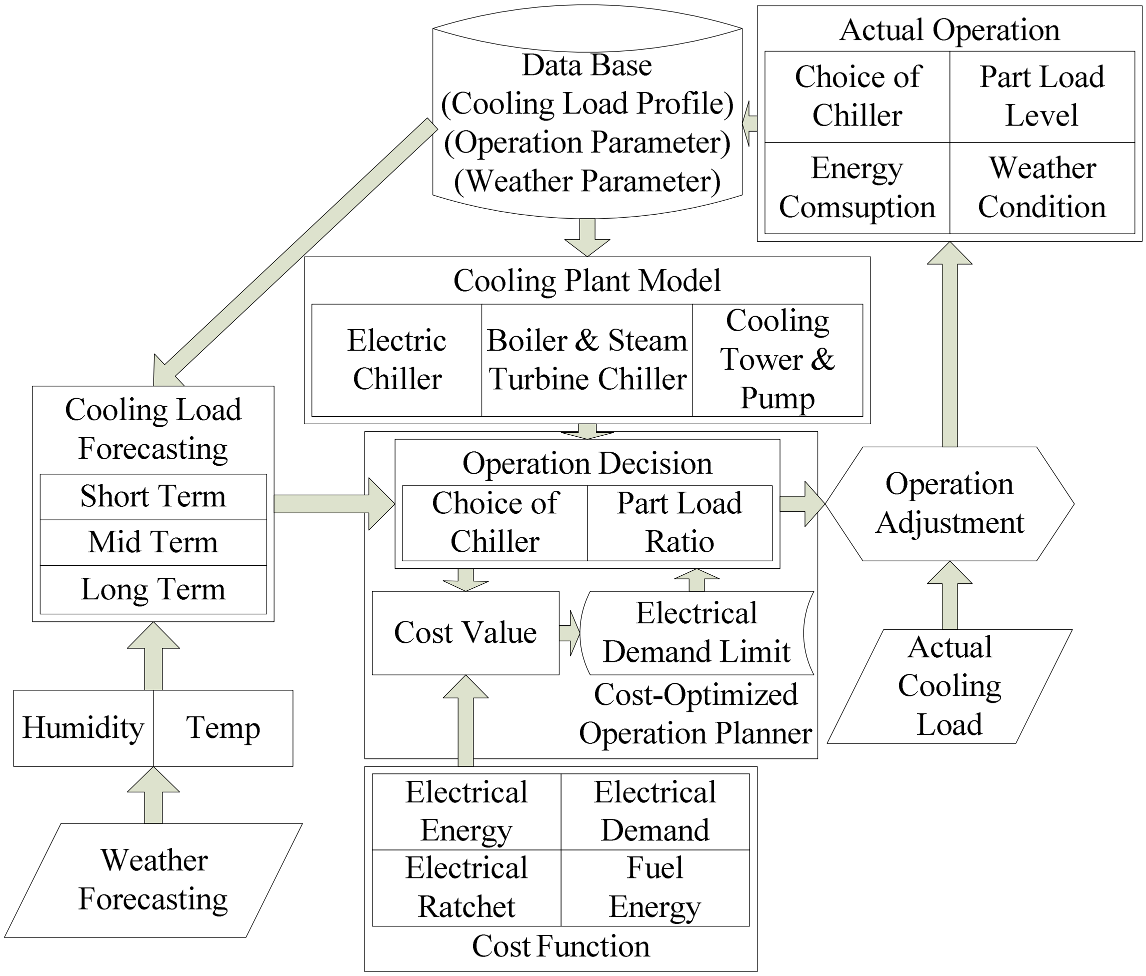

Figure 3.1 Structure of cost-optimized operation methodology

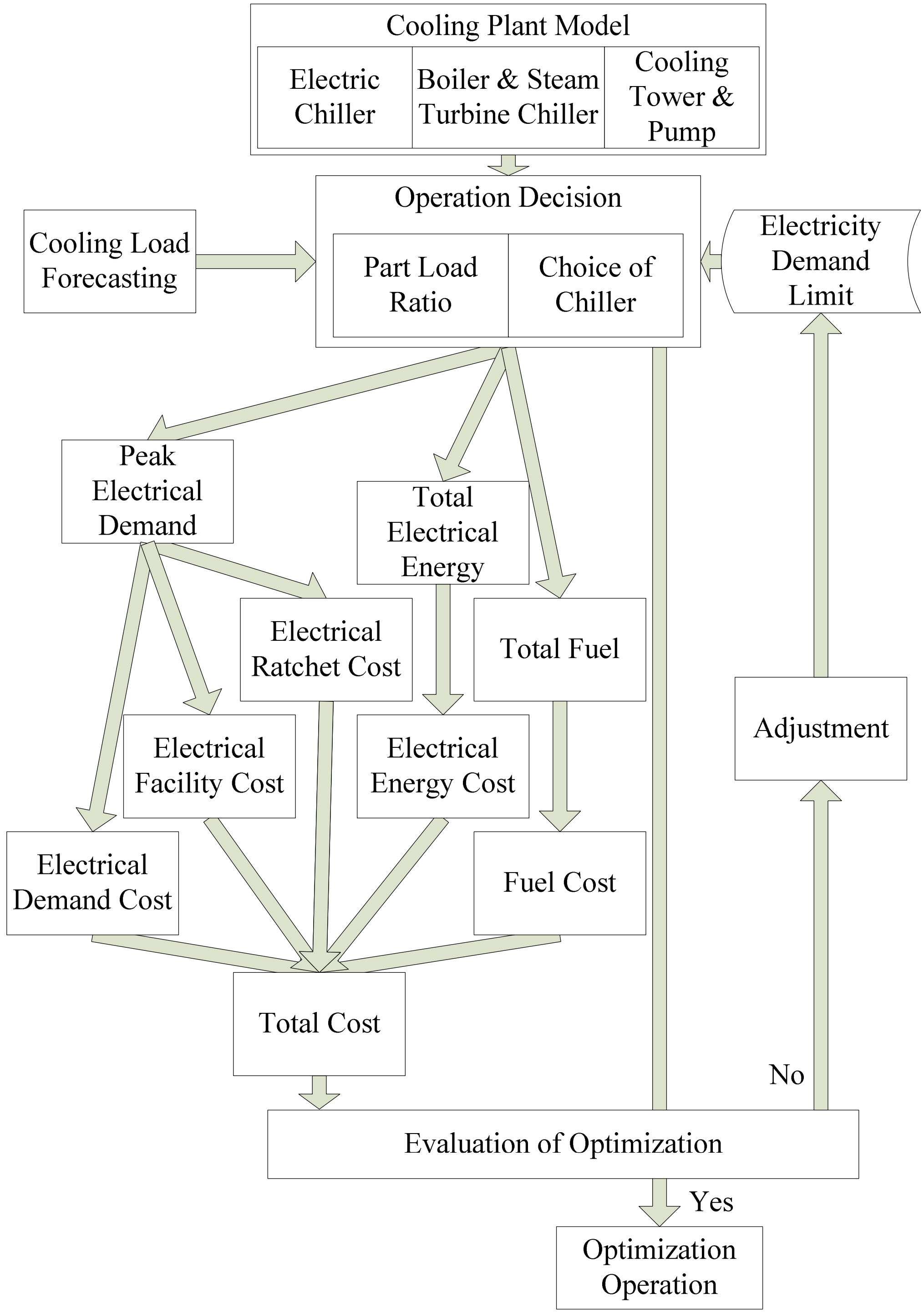

Figure 3.2 Methodology structure of cost optimal operation planner

The detailed structure of cost-optimized operation planner is shown in the Figure 3.2. The initial value of electrical demand limit which is usually the lowest boundary of the feasible value is first generated. Then the operation decision of each unit in the system will be generated under the constraint of the electrical demand limit. Electrical chillers will be operated to generate the cooling capacity at the lowest level of electrical energy consumption. However, if the electrical chiller cannot provide enough cooling capacity under the electrical demand limit, the steam turbine chiller will be operated to generate the remaining cooling capacity. Once the operation decision variables for the entire planning horizon are generated, the total electrical energy, peak electrical demand and total fuel usage can be obtained. Total cost will be calculated by summing up the five terms in the cost function. Then incremental adjustment will be made to the peak electrical demand limit, and redo the above process again. After comparing the total cost among all the possible operation situations, the optimal operation decision will be displayed to the operator at last.

3.2 Nomenclature

The following mathematical symbols are used in this research.

Parameters and variables

α	Demand ratchet factor

β	Summer month indicator, 1 if the current month is a summer month, and 0 otherwise
γ	Monthly interest rate
a_0, a_1, a_2	Coefficients for the power-PLR regression function of electric chiller
b_0, b_1, b_2	Coefficients for the fuel-PLR regression function of steam turbine chiller
C	Cost function
c	Cost rate
d	Total cooling load
E	Function or value of electrical energy supply or consumption
F	Function or value of fuel consumption
M	Total number of steam turbine chiller
N	Total number of electric chiller
P	Peak electrical power supply or consumption

p	Actual peak electrical power supply or consumption recorded in the last year
Q	Cooling capacity produced by chiller
R	Electrical demand ratchet
r	Electrical facility ratchet
T	Time horizon
u	Decision variable of on-off status of chiller
x	Decision variable of part load ratio (PLR) of chiller
y	Decision variable of peak electrical demand limit
ΔP	Difference of actual peak demand in the past year and the demand ratchet in the winter demand month, non-negative
PLR	Part load ratio

Subscripts

i	Chiller

t	Time period
k	Month of the year for the planning controller, different from the calendar year, starting from the first summer month
K	Current month

Superscripts

D	Designed Value
F	Fuel
L	Local electricity supplier (LES)
S	Start up
W	National electricity supplier (WAPA)
CT	Cooling Tower
DM	Electrical demand cost
DR	Electrical demand ratchet cost

EC	Electric Chiller
EG	Electrical energy cost
FC	Electrical facility cost
PR	Primary service
SC	Secondary service
SC1	Secondary service Part I, for cooling plant
SC2	Secondary service Part II, for other facility
TC	Steam turbine chiller
Max	Maximum value
TWP	Tower water pump
CWP	Chilled water pump
Total	Total term

3.3 Assumptions

In this research, the following assumptions are made.

- There are *N* electric chillers, *M* steam turbine chillers and one boiler in the system.
- All equipment (chillers, boiler, pumps and cooling towers) is considered to have a constant energy efficiency performance over time. In addition, the efficiency will not be affected by other factors, such as weather and seasons.
- The temperatures of inflow and outflow chilled water are constant.
- The temperatures of inflow and outflow cooling tower water are constant.
- The steam generated by the boiler will only be used by steam turbine chillers to produce chilled water.
- There is no start-up cost for electric chillers, due to the insignificant start-up time and cost.
- The chillers can be turned off at the start of any time period and turned on at the start of the next time period, and vice versa.

3.4 Cooling Plant Energy Consumption Model

A central cooling plant generally consists of chillers, chilled water pumps, tower water pump and cooling towers, and the total electricity consumed should account for the electricity used by these four types of equipment.

The electricity consumed during a short time period by the electric chiller can be expressed as a quadratic regression function of its part load ratio (PLR). This general cooling plant modeling method was introduced by J.E. Braun [19].

$$E_i^{EC} = E_i^{EC,D}\left(a_{0,i} + a_{1,i}PLR_i + a_{2,i}PLR_i^2\right) \quad \text{Eq 1}$$

where $PLR_i = Q_i / Q_i^D$, and $a_{0,i}$, $a_{1,i}$, $a_{2,i}$ are the coefficients for the power-PLR regression function of the *i*th electric chiller.

Although the performance of chillers is always affected by the weather condition, the influence of the weather condition is beyond the scope of this research and not considered. However, adjustment can be made to achieve a more accurate result [19].

The electricity consumed by cooling towers and water pumps is complicated: it depends on the type of the driving motor and the structure of the cooling system. Generally, for variable speed drive cooling towers and water pumps, the electricity consumed by each unit can be expressed as a cubic regression function of its PLR. For constant speed drive cooling towers and water pumps, the electricity consumed is considered as a constant value. At the same time, if a chiller is solely served by a certain chilled water pump or tower water pump, then the operation decision of the pumps is related to that of chillers. On the contrary, if a chiller can be served by any of the chilled water pumps or tower water pumps in the system, the operation decision of the pumps is related to the total cooling load. More specific methodology for operation decision of water pumps and cooling towers was described by J.E. Braun [25].

Then the total electrical energy consumed by the cooling system through the entire time horizon *T* is

$$E^{Total} = \sum_{t=1}^{T} E_t = \sum_{t=1}^{T}\left(\sum_{i=1}^{N} E_{t,i}^{EC} + E_t^{TWP} + E_t^{CWP} + E_t^{CT}\right) \quad \text{Eq 2}$$

where E_t is the electrical energy used by the entire cooling system in the short time period t. E_t consists of four part: $E_{t,i}^{EC}$ represents the electrical energy used by electric chiller i in the time period t. E_t^{TWP}, E_t^{CWP} and E_t^{CT} are the electrical energy used in the time period t by tower water pumps, chilled water pumps and cooling towers, respectively.

If the time period t is short enough or set to be the measurement period of electrical meters, E_t can be considered as electrical power/demand. Then the maximum peak electrical demand, P_{Max}, is the maximum of E_t throughout the entire time horizon T.

$$P^{Max} = \max_{1 \le t \le T} \{E_t\} \qquad \text{Eq 3}$$

In the same way, the fuel consumed during any short time period by the steam turbine chiller can also be expressed as a quadratic regression function of its PLR.

$$F_i^{TC} = F_i^{TC,D}\left(b_{0,i} + b_{1,i} PLR_i + b_{2,i} PLR_i^2\right) \qquad \text{Eq 4}$$

where $PLR_i = Q_i / Q_i^D$, and $b_{0,i}$, $b_{1,i}$, $b_{2,i}$ are the coefficients for the fuel-PLR regression function of the ith steam turbine chiller.

Then the total fuel used by the steam turbine through the entire time horizon T is

$$F^{Total} = \sum_{t=1}^{T}\left(F_t + F_t^S\right) = \sum_{t=1}^{T}\sum_{i=1}^{M}\left(F_{t,i}^{TC} + F_{t,i}^S\right) \qquad \text{Eq 5}$$

where F_t is the fuel used by the steam turbine chiller in the time period t, and F_t^S is the start-up cost of steam turbine chillers in the time period t. $F_{t,i}^S$ is a function determined by zero-one decision variables, $u_{t-1,\,i}$ and $u_{t,\,i}$.

Without losing generality, the cooling plant is assumed to be powered by secondary service line in this study. Thus the electrical energy terms described above have the following relations with the terms used in the cost function in Section 3.5.

$$E_K^{SC1} = E_K^{Total} \quad \text{Eq 6}$$

$$E_K^{SC} = E_K^{SC1} + E_K^{SC2} \quad \text{Eq 7}$$

$$P_K^{SC1} = P_K^{Max} \quad \text{Eq 8}$$

$$P_K^{SC} = P_K^{SC1} + P_K^{SC2} \quad \text{Eq 9}$$

3.5 Cost Function

In this research, the cost function of a billing period (usually a calendar month) for a hybrid cooling plant consists of five terms: electrical energy cost, electrical demand cost, electrical facility cost, fuel cost and demand ratchet punitive cost. The total cost caused by the operation of the current month *K* is formulated as Eq 10.

$$C_K^{Total} = C_K^{EG} + C_K^{DM} + C_K^{FC} + C_K^{F} + C_K^{DR} \quad \text{Eq 10}$$

The first four terms on the right hand side are the costs that appeare in the bill of every month, and are defined as the current month billing cost.

The demand ratchet punitive cost does not appear in the bills of the summer months, but the bills for the following winter months. However, the demand ratchet is taken into account in a summer month, because the demand ratchet punitive cost is caused by the operation of the cooling system in that summer month. Then the demand ratchet cost incurs as a punitive cost, only if the peak demand set by the summer month affects the demand ratchet level for the following winter months. If the current month is a winter month, then the first four terms make up the total energy cost, and there is no demand ratchet punitive cost, because the operation of the cooling system in the winter month does not affect any of the other 11 months.

In the electricity industry, a simple energy price policy with a single rate is rare for high demand customers [26-31]. Considering the persistent high demand and the burden on the grid, a special plan is usually designated for these customers. In such special plans, a time-of-use differentiated rate policy is usually applied to encourage the cost saving by reducing energy consumption during peak period. In some cases, not only different energy and demand rates are applied in peak and off-peak periods, but also demand ratchet policy is applied.

In this research, a more complex cost structure is studied. First, two electricity sources with different cost rates are considered. Different cost rates are usually applied to the electrical energy or electrical demand consumed from the two sources. One source is usually a national electricity supplier such as Western Area Power Administration (WAPA), and the other is a local supplier. For example, a customer may receive main part of the electrical supply from a national large wind field or large dams, while the rest is provided by local electricity generation plants.

Second, according to the different electrical voltages, the electricity is delivered through the primary service line and secondary one. In order to reduce the electrical energy lost on the electricity line, it is usually recommended that the electrical service be delivered at a higher voltage, which is usually called primary service. However, a lower voltage service which is usually called secondary service exists due to special needs. The electrical services delivered through the two types of service usually have different cost rates.

Although the electrical service from two sources is delivered through both primary and secondary service lines, usually only the part of supply from the local suppliers is charged at different electrical service rates. The different cost rates based on service type are usually not applicable to national electricity supplier, because the electricity supply and cost rate for the national electricity supplier are fixed number based on the contract. Then the amount of primary and secondary services from local supplier is calculated according to the ratio of these two types of service recorded in total.

For example, if 6,000,000 kWh and 4,000,000 kWh are delivered through primary and secondary services respectively in January, then the total energy supply is 10,000,000 kWh. Therefore the ratios of the primary and secondary services against the total supply are 60% and 40%, respectively. Based on the contract, the national supplier supplied 7,866,000 kWh in January. By subtracting 7,866,000 kWh from the total supply, the balance provided by local supplier is 2,134,000 kWh. This balance of 2,134,000 kWh is then divided into two parts based on the ratio of 60% and 40%. Thus the primary electrical service provided by the local supplier is $2,134,000 \times 60\% = 1,280,400$ kWh, and the secondary electrical service is $2,134,000 \times 40\% = 853,600$ kWh.

Thus the electrical energy cost can be calculated through Eq 11.

$$C_K^{EG} = c_K^{EG,W} E_K^W + c_K^{EG,PR,L} \frac{E_K^{PR}}{E_K^{PR} + E_K^{SC}} \left(E_K^{PR} + E_K^{SC} - E_K^W \right) + c_K^{EG,SC,L} \frac{E_K^{SC}}{E_K^{PR} + E_K^{SC}} \left(E_K^{PR} + E_K^{SC} - E_K^W \right) \quad \text{Eq 11}$$

The demand cost is calculated in the same way as follows.

$$C_K^{DM} = c_K^{DM,W} P_K^W + c_K^{DM,PR,L} \frac{P_K^{PR}}{P_K^{PR} + P_K^{SC}} \left(P_K^{PR} + P_K^{SC} - P_K^W \right) + c_K^{DM,SC,L} \frac{P_K^{SC}}{P_K^{PR} + P_K^{SC}} \left(P_K^{PR} + P_K^{SC} - P_K^W \right) \quad \text{Eq 12}$$

Because both the energy and demand consumed through the primary service line and secondary service line Part II are stable, the values of the current month are estimated by the average value recorded last year.

During the winter months, the demand ratchet policy is applied in addition to the basic policy mentioned above. The main idea of the demand ratchet is that the monthly billing demand from the local supplier for the winter months is the higher of either (1) the maximum demand during the month or (2) α of the highest maximum demand established by bills rendered in summer months before. Then the electrical demand cost in winter months is calculated by Eq 13.

$$C_K^{DM} = \begin{cases} c_K^{DM,W} P_K^W + c_K^{DM,PR,L} \dfrac{P_K^{PR}}{P_K^{PR} + P_K^{SC}} \left(P_K^{PR} + P_K^{SC} - P_K^W \right) + c_K^{DM,SC,L} \dfrac{P_K^{SC}}{P_K^{PR} + P_K^{SC}} \left(P_K^{PR} + P_K^{SC} - P_K^W \right) & P_K^{PR} + P_K^{SC} - P_K^W > R_K \\ c_K^{DM,W} P_K^W + c_K^{DM,PR,L} \dfrac{P_K^{PR}}{P_K^{PR} + P_K^{SC}} R_K + c_K^{DM,SC,L} \dfrac{P_K^{SC}}{P_K^{PR} + P_K^{SC}} R_K & P_K^{PR} + P_K^{SC} - P_K^W \le R_K \end{cases} \quad \text{Eq 13}$$

Figures 3.3 and 3.4 illustrate the demand ratchet policy.

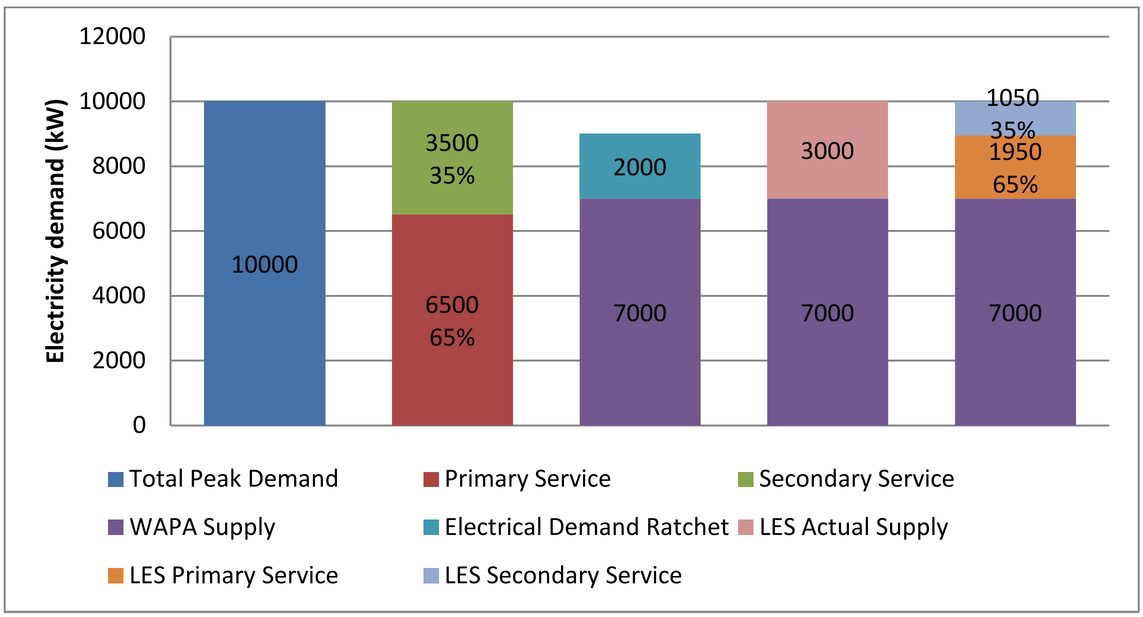

Figure 3.3 Billing demand when the actual peak demand is higher than demand ratchet

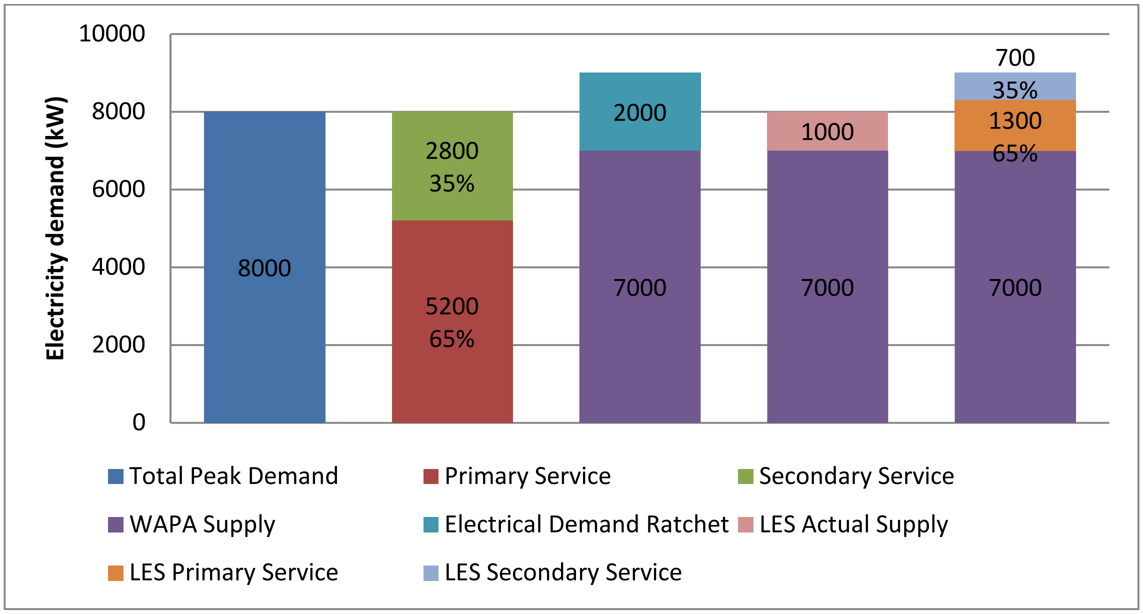

Figure 3.4 Billing demand when the actual peak demand is lower than demand ratchet

If the current month is a summer month, the value of demand ratchet of the current month is the higher of either (1) the demand ratchet of last month or (2) the new demand ratchet obtained based on the peak electrical demand established in the current month. If the current month is a winter month, then the value of demand ratchet of current month equals to the demand ratchet of the last month, and eventually equals to the highest demand ratchet set in the previous summer months. The demand ratchet is zero at the start of a new fiscal year starting from the first summer month. Thus the demand ratchet is expressed by the following equation.

$$R_k = \begin{cases} 0 & k = 0 \\ \max\left\{\alpha\left(P^{PR} + P^{SC} - P_k^W\right), R_{k-1}\right\} & \beta_k = 1 \\ R_{k-1} & \beta_k = 0 \end{cases} \qquad \text{Eq 14}$$

In some cases, the facility cost exists in addition to the demand cost. The facility cost can be considered as a special term of demand cost, because it is also charged based on the electrical power. The facility cost is the sum of the cost generated through both primary and secondary services, based on the total supply through each service and the different rates of each service. However, the national supplier does not charge the facility cost, while the local supplier charges all the facility cost. Thus even if some part of the electrical energy and demand comes from the national supplier through each service type, the facility cost is charged based on the total usage of each service type by local supplier. Because the operation decision of the chiller system does not affect the primary service line in this research, the facility cost of the current month *K* only includes the cost for the secondary service, and is calculated by the following equation. At the same time, the ratchet policy is also applied to the facility cost.

$$C_K^{FC} = \begin{cases} c_K^{FC} P_K^{SC} & P_K^{SC} > r_K \\ c_K^{FC} r_K & P_K^{SC} \le r_K \end{cases} \qquad \text{Eq 15}$$

where the facility demand ratchet is as follows.

$$r_k = \begin{cases} 0 & k = 0 \\ \max\left\{\alpha P^{SC}, r_{k-1}\right\} & \beta_k = 1 \\ r_{k-1} & \beta_k = 0 \end{cases} \qquad \text{Eq 16}$$

According to the ratchet policy, when the actual peak electrical demand in a winter month is lower than the demand ratchet, the customer would pay more than the cost that calculated based on the actual peak electrical demand that they used during that winter month. The same situation appears in calculating the facility cost. This part of cost is defined as the winter month ratchet cost. The sum of winter month ratchet costs for all winter months is defined as the demand ratchet punitive cost.

Although winter month ratchet cost does appear in the following winter months, it is rational to consider this cost in the summer months as a punitive cost, because it is mainly caused by the high peak electrical demand set during the summer months. Therefore, if the current month *K* is a winter month, there is no ratchet punitive cost. However, if the current month *K* is a summer month, the ratchet punitive cost equals to the greater of (1) the ratchet punitive cost caused by the operation of cooling plant in the previous summer months or (2) the sum of winter month ratchet costs for all winter months calculated based on the new peak electrical demand used in the current month *K*. Then the ratchet punitive cost of the current month *K* is as follows.

$$C_K^{DR} = \beta_K \max\left\{C_{K-1}^{DR}, \sum_{k=K}^{12} C_k^{DR}\right\} \quad \text{Eq 17}$$

The winter month ratchet cost of a future month *k* consists of two terms: the demand ratchet cost and the facility ratchet cost. The two costs are calculated through the basic policy based on the difference of the ratchet value and the actual value.

$$C_k^{DR} = C_k^{DM}\left(\Delta P_k^{DM}\right) + C_k^{FC}\left(\Delta P_k^{FC}\right) \quad \text{Eq 18}$$

$$\Delta P_k^{DM} = \max\left\{0, \alpha\left(P_K^{PR} + P_K^{SC} - P_K^{W}\right) - \left(p_k^{PR} + p_k^{SC} - p_k^{W}\right)\right\} \quad \text{Eq 19}$$

$$C_k^{DM}\left(\Delta P_k^{DM}\right) = c_k^{DM,PR,L} \Delta P_k^{DM} \frac{p_k^{PR}}{p_k^{PR} + p_k^{SC}} + c_k^{DM,SC,L} \Delta P_k^{DM} \frac{p_k^{SC}}{p_k^{PR} + p_k^{SC}} \quad \text{Eq 20}$$

$$\Delta P_k^{FC} = \max \{0, \alpha P_K^{SC} - p_k^{SC}\}$$ Eq 21

$$C_k^{FC}\left(\Delta P_k^{FC}\right) = c_k^{FC} \Delta P_k^{FC}$$ Eq 22

Because the actual peak electrical demand in the winter month k, after summer months is unknown, the value recorded in the last year, p_k, is used to estimate the future value.

3.6 Cooling Load Forecasting

In this section, two traditional forecasting models are presented and discussed. As this research is not meant to be a research which focuses on cooling demand forecasting, only the basic level work is conducted.

3.6.1 Time Series Model

The time series model is such a model that the current value of the cooling load, d_t, is only related to its past values, d_{t-1}, d_{t-2}, d_{t-3}, … . Usually, an autoregressive (AR) model or an autoregressive moving average (ARMA) model is applied. The advantage of this model is that it is easy to implement, because there is only one variable to the model which is the past value. In another word, the forecasting result is relatively independent of factors, such as ambient weather conditions and building occupancy. At the same time, this model usually promises an accurate short-term forecasting result. The model also has a quick response to the uncertainty and fluctuation. However, the accuracy decreases as the forecasting lead time increases, because the error in each time step will be accumulated to the next step. So it is not rational to use time series model for mid-term or long-term forecasting.

3.6.2 Multiple Regression Model

Different from time series model, the multiple regression model is a straight-forward model which tries to take all the factors into consideration. First order or second order regression is usually studied. The advantage of this model is that it is lead time independent. That is to say, the forecasting result is only related to the number of factors considered and the sufficiency of the data. But on the contrary there are several disadvantages. First, it depends on the accuracy of the estimation of each factor. Second, it is impossible to take all the factors into consideration. Third, the model usually does a bad job in response to the uncertainty. In order to overcome the shortage of the model, usually other works or strategies are needed. For example, one simple method is to take the variance into consideration and then add a safety factor into the forecasting result. Another method is to do an uncertainty analysis through variance analysis or outlier analysis, so that we can structure the uncertainty in the cooling load forecasting.

3.7 Cost-optimized Operation Planning Model and Solution Method

In this research, the planning horizon is T periods, which is set to be a billing cycle (a calendar month). If we change the PLR_i in Eq 1 and Eq 4 to the non-negative discrete integer decision variable $x_{t,i}$ and define $u_{t,i}$ as the zero-one decision variable in Eq 5 for the cost-optimized operation planning model, then for each chiller i at a time period t the operation state of that unit is denoted by these two variables. An electric chiller is off at time t if $x_{t,i}=0$, and on if $x_{t,i}>0$ and within the feasible operation range. A steam turbine chiller is off at time t if $u_{t,i}=0$ while also $x_{t,i}=0$, and on if $u_{t,i}=1$while also $x_{t,i}>0$ and within the feasible operation range as well. Combined with the cooling load forecasting model and the plant model, the predictive optimal control model is formulated as a mixed-integer nonlinear program (MINLP) as follows:

$$z = \min_{u,x} C_K^{Total} = \min_{u,x} C_K^{EG} + C_K^{DM} + C_K^{FC} + C_K^{F} + C_K^{DR} \qquad \text{Eq 23}$$

s.t.

$$\sum_{i=1}^{N} Q_i^{EC,D} x_{t,i} + \sum_{i=1}^{M} Q_i^{TC,D} x_{t,i} \geq d_t \quad \forall t \qquad \text{Eq 24}$$

where d_t is the cooling load in the time period t. The cooling load constraint ensures the cooling load generated is at least equal to the cooling load from campus.

Due to the general computational complexity of the MINLP, the real time implementation is usually limited. To overcome this problem, a dual stage optimization method is applied in this research by introducing another decision variable, y_K, the peak electrical demand limit of the secondary service in month K.

In the first stage, the optimal solution for each time period under the constraint of y_K and d_t is recast to a nonlinear program problem. There are two input values to the problem of first stage: the cooling load, d_t, and the peak electrical demand limit, y_K. For each time period, the cooling load is first met by the electric chillers under the constraint of y_K. If the electric chiller cannot provide enough cooling capacity, the portion of the cooling capacity that is not met by the electric chillers is then filled by steam turbine chiller. Therefore, the optimal solution of any time period is regarded as a function of cooling load and peak electrical demand limit. The optimal solution of the first stage is preprocessed and stored in data base. The second stage is then simplified to be an integer nonlinear program with only one decision variable – peak electrical demand limit, y_K.

The advantages of this solution strategy are: 1) remove the repeating calculation for each individual time period; 2) greatly reduce the requirement of calculation capacity for real time implementation; 3) as the calculation for each individual time period with different inputs become a separate pre-process, the data base of the solution can be updated every time the plant model is updated.

By applying the dual stage solution strategy, the optimal production planning model becomes:

$$z = \min_{u,x,y} C_K^{Total} = \min_{u,x,y} C_K^{EG} + C_K^{DM} + C_K^{FC} + C_K^{F} + C_K^{DR} \qquad \text{Eq 25}$$

s.t.

$$\sum_{i=1}^{N} Q_i^{EC,D} x_{t,i} + \sum_{i=1}^{M} Q_i^{TC,D} x_{t,i} \geq d_t \quad \forall t \qquad \text{Eq 26}$$

$$P_t^{SC} \leq y_K \quad \forall t \qquad \text{Eq 27}$$

$$r_{K-1} \leq y_K \qquad \text{Eq 28}$$

$$\alpha\left(P^{PR} + y_K - P_K^{W}\right) \geq R_{K-1} \qquad \text{Eq 29}$$

CHAPTER 4

CASE STUDIES

In this section, first the cost-optimized operation of the cooling plant at the University of Nebraska-Lincoln (UNL) City Campus in August 2010 is simulated based on the actual cooling load recorded in the same period. This simulation result is compared with the actual manual operation performed at that time. Second, simulated cost-optimized operation plans based on predicted cooling load profiles are also generated for the same period and compared with the above results.

4.1 Description of Case Study Conditions

The central cooling plant of the UNL City Campus is well designed to support the development and implementation of cost efficient technologies and practices, as the UNL has established an enhanced control system as well as a sufficient database.

The UNL City Campus cooling plant currently uses four electric chillers. Electric Chiller 1 has 5000 tons of maximum capacity, Electric Chiller 2 has 4500 ton capacity, and Electric Chillers 3 and 4 have 2000 each. By capacity, Electric Chillers 1 and 2 are called large chillers and Electric Chillers 3 and 4 are called small chillers. The designed electrical energy consumption rates of the four chillers are 4310 kW, 3030 kW, 1324 kW and 1324 kW respectively. The four electric chillers are usually used to meet the entire cooling load when cooling load shifting to the steam turbine chillers is not necessary. The electric chillers are still responsible for the majority of the cooling load even when cooling load shifting occurs.

In addition, the cooling plant also uses one steam turbine chiller, one boiler, six tower water pumps, five chilled water pumps, three arrays of cooling towers, and a distribution loop serving each building of the campus. The steam turbine chiller has a maximum capacity of 5000 tons/h. It is driven by the 600 psi steam which is generated by the boiler. The pumps and cooling towers are all powered by electricity.

The cooling plant at the UNL City Campus is powered only by the secondary service. The electricity service supplied through 12kV and 4kV lines are considered as the primary service and secondary service respectively. For UNL, there are two lines of the secondary service. The first line is the only one currently supplying the electricity to the cooling plant.

The energy cost function and policy described in Section 3.5 are all applied to the case of UNL. The electricity rates of the local supplier are given in the Table 4.1. The rates and allocations of electrical demand and energy from national supplier are shown in the Table 4.2. The fuel rate is provided in Table 4.3.

Table 4.1 Electricity rates of local supplier [32]

Rates	Winter Energy (Oct-May) ($/kWh)	Summer Energy (Jun-Sep) ($/kWh)	Demand ($/kW)	Facilities ($/kW)
Primary	0.0205	0.0282	12.70	4.00
Secondary	0.0200	0.0272	13.05	4.40

Table 4.2 Rates and allocations of electrical demand and energy from national supplier [33,34]

Month	Electrical Demand (kW)	Electrical Energy (kWh)	Demand Rate ($/kW)	Energy Rate ($/kWh)
Jan	14,220	7,866,000	7.65	0.01905
Feb	14,220	7,539,000		
Mar	14,220	7,747,000		
Apr	14,220	7,499,000		
May	17,630	8,491,000		
Jun	18,740	9,985,000		
Jul	18,965	9,824,000		
Aug	18,965	10,581,000		
Sep	18,196	9,396,000		
Oct	17,745	8,179,000		
Nov	14,200	7,580,000		
Dec	14,015	7,388,000		

Table 4.3 Fuel cost rate [34]

Month	Cost Rate ($/MMBtu)	Month	Cost Rate ($/MMBtu)	Month	Cost Rate ($/MMBtu)
Jan-2010	7.48	May-2010	6.17	Sep-2010	6.68
Feb-2010	7.61	Jun-2010	6.59	Oct-2010	6.39
Mar-2010	7.06	Jul-2010	6.16	Nov-2010	6.03
Apr-2010	6.70	Aug-2010	6.08	Dec-2010	6.42

In this research, the start-up cost only contains the cost for warming up the steam turbine chiller. The boiler is always standby to use, because additional steam is needed to reheat the cooling air to meet the different temperature set points for different sections of the buildings on campus. The steam turbine chiller usually takes about 2 hours to warm up to standard working condition.

4.2 Current Manual Operation

The cooling system at the UNL City Campus is operated manually based on the experience of the human operators by the following strategy. The control system keeps measuring the temperatures of inflow and outflow cooling water. If there is an increase in the difference between the inflow and outflow temperatures, the operator will adjust the part load ratio of the operating chillers or turn on another chiller to increase the cooling capacity, and vice versa if there is a decreased temperature difference.

At the same time, the operator decides the operation of steam turbine chiller to shift cooling load from electric chiller by using the following 10 days' weather forecast (mainly the temperature) every early morning. If there is a high temperature within the near future, for example for the next 2 days, the operators will judge based on their experience if it is necessary to operate the steam turbine chiller in that day to shift part of the cooling load from the electric chillers. If the load shifting is expected, the operator will warm up the steam turbine chiller in the early morning of that day. The operator determines when the steam turbine chiller should be turned on and how much cooling load should be shifted all based on his past experience.

The manual operation profile of August 2010 is shown in Figure 4.1.

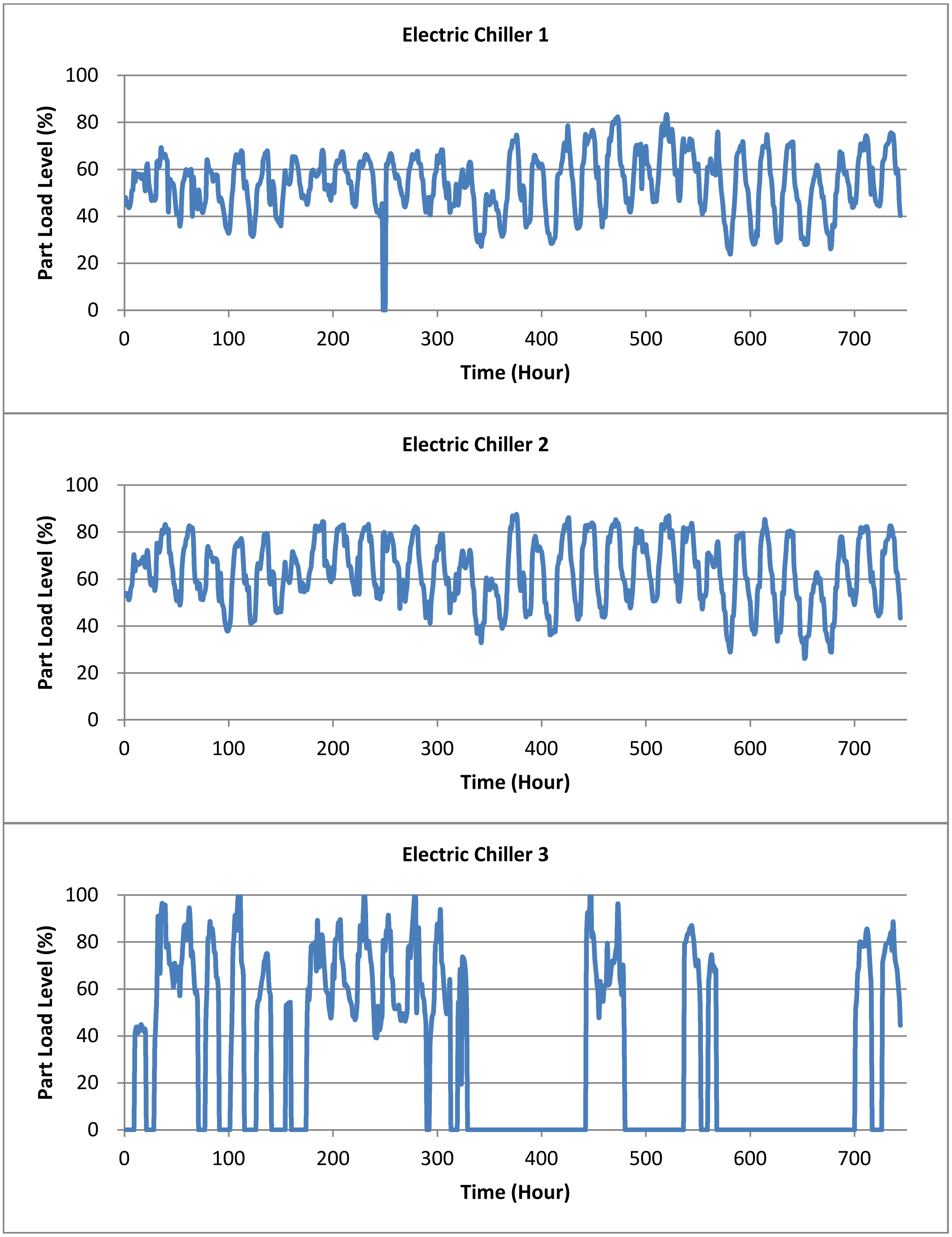

Figure 4.1 Manual operation profile of August 2010 (continues on the next page)

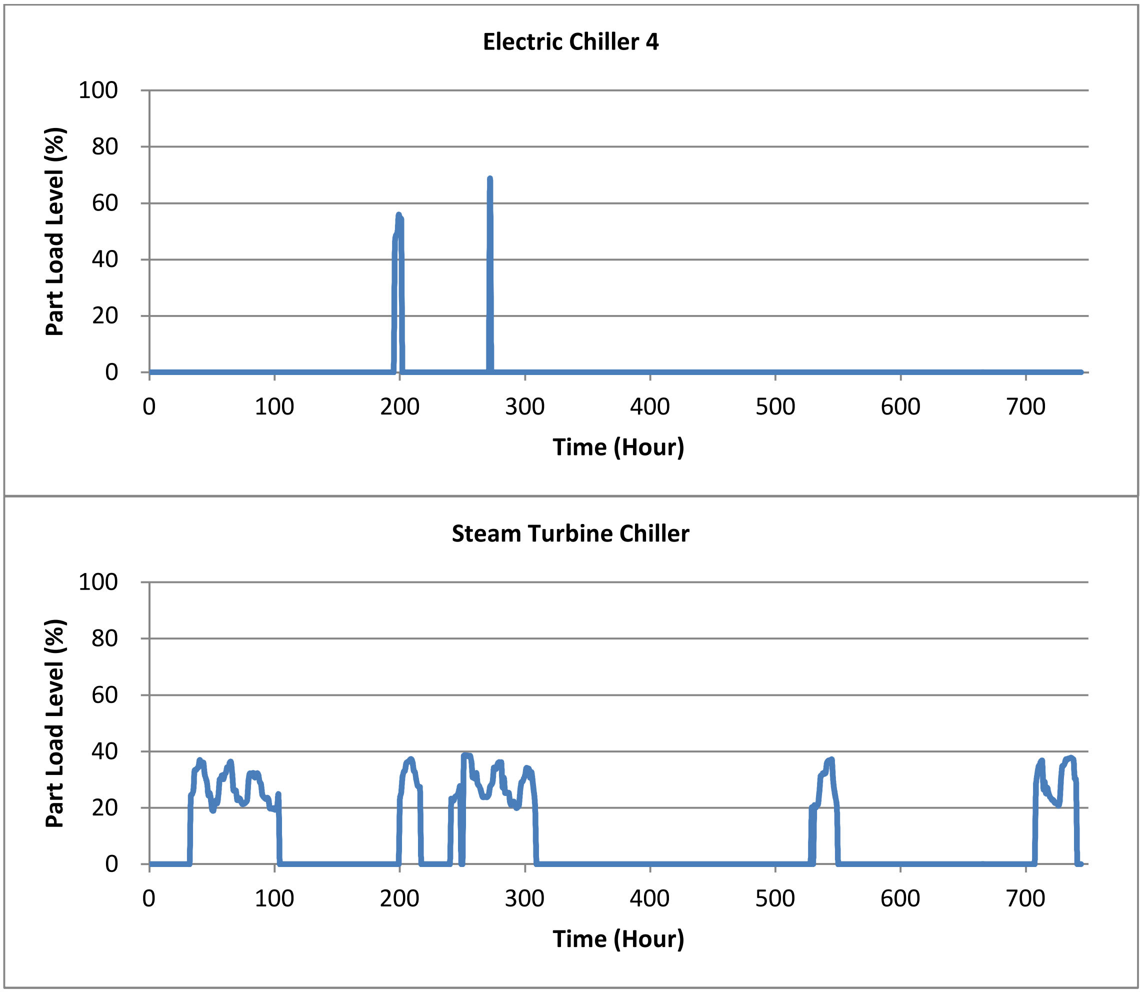

Figure 4.1 Manual operation profile of August 2010 (continued from the previous page)

Under the current manual operation strategy, Electric Chillers 1 and 2 are operated most often. The two big chillers provide most of the cooling capacity. The cooling load is generally assigned to Electric Chillers 1 and 2 according to the ratio of their designed capacity. Electric Chiller 3 is operated to cope with the load fluctuation, even if Electric Chillers 1 and 2 are not at their full part load ratio. Electric Chiller 4 is only operated in case of breakdown or maintenance of other chillers. Generally, the steam turbine chiller is operated when the total campus cooling load is greater than 9000 tons/hour.

4.3 Simulated Cost-optimized Operation under the Perfect Information of the Cooling Load

4.3.1 Simulated Cost-optimized Operation

In this section, the simulated cost-optimized operation decision for each hour is generated through the cost-optimized operation planner based on the 744 data points of actual cooling load of the City Campus recorded in August 2010. The simulation is conducted under the perfect information of the cooling load throughout the entire billing cycle (the colander month of August 2010), and performed using the methodology and modes through the dual-stage solution method described in Chapter 3. The optimization is performed by a computer program written on Matlab® [34]. The time horizon is set to be a billing period (the calendar month of August 2010).

In the current manual operation (shown in Figure 4.1), the two big chillers meet the main part of the cooling load and the two small chillers cover some peaks and fluctuation. But the generated optimal solution indicates operating the chillers based on their efficiency: meet the main part of cooling load by using the two small electric chillers which are more efficient, and operate Electric Chiller 3 only when extra capacity is needed. Operating Electric Chiller 1 is the least economical choice.

The cost-optimized operation planning also suggests that the steam turbine chiller should be operated more often. When the cooling load is greater than 7,000 tons/hour (the Chillers 3 and 4 are operated at the full part load ratio and Chiller 2 is operated at the part load ratio of 80%), it could be more economical to use the steam turbine chiller to cover the rest portion of the cooling load which is higher than 7,000 tons/hour.

The result of cost-optimized operation profile is plotted in Figure 4.2.

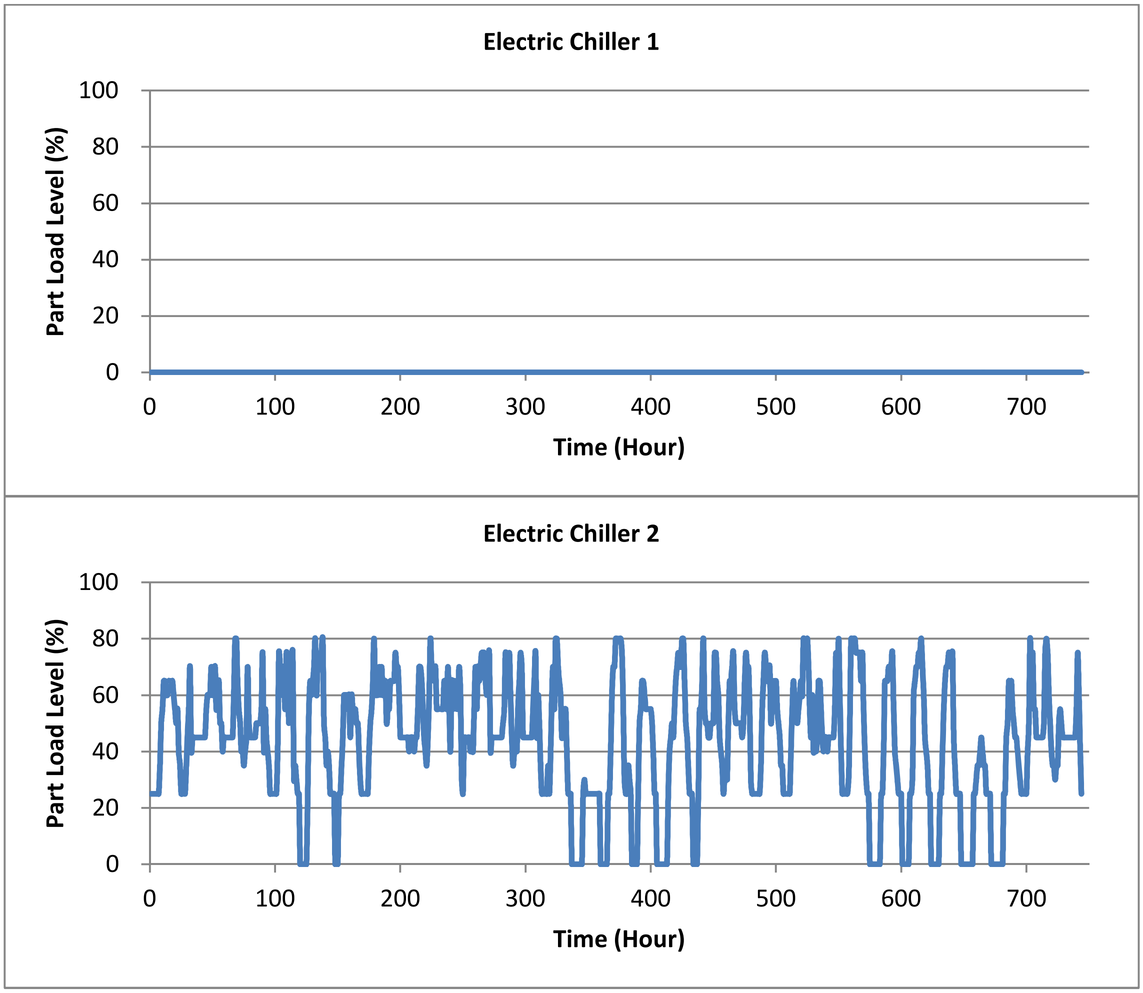

Figure 4.2 Simulated cost-optimized operation profile of August 2010 under the perfect information of cooling load (continues on the next page)

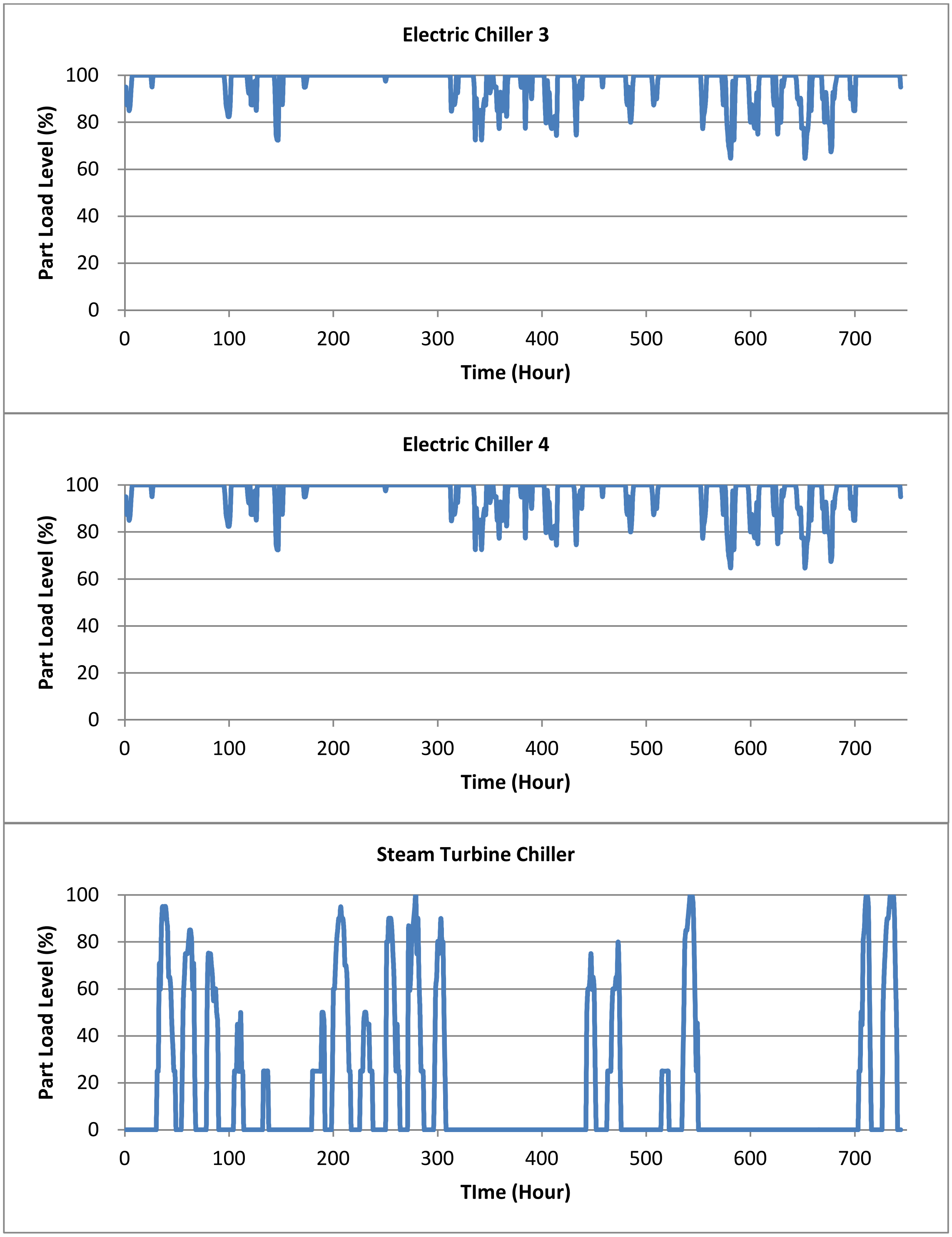

Figure 4.2 Simulated cost-optimized operation profile of August 2010 under the perfect information of cooling load (continued from the previous page)

4.3.2 Comparison of Cost

Figures 4.3 and 4.4 illustrate cost terms between the simulated cost-optimized operation and actual manual operation. In those two graphs, the individual cost terms in the current month billing cost and the total cost are compared between the current manual operation and the simulated cost-optimized operation.

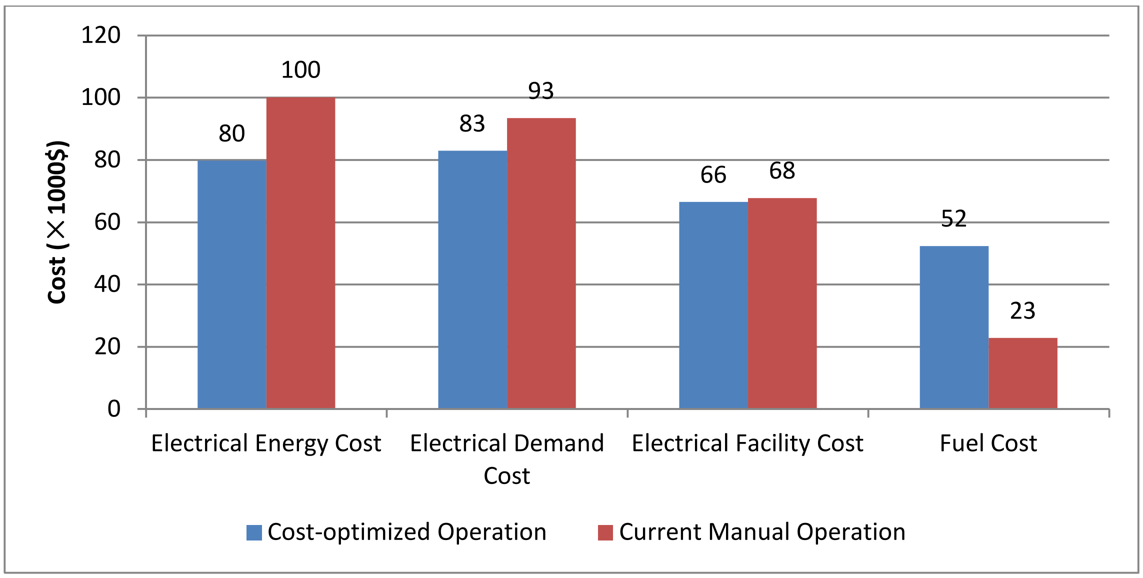

Figure 4.3 Comparison of individual cost terms in the current month billing cost between simulated cost-optimized operation and actual manual operation

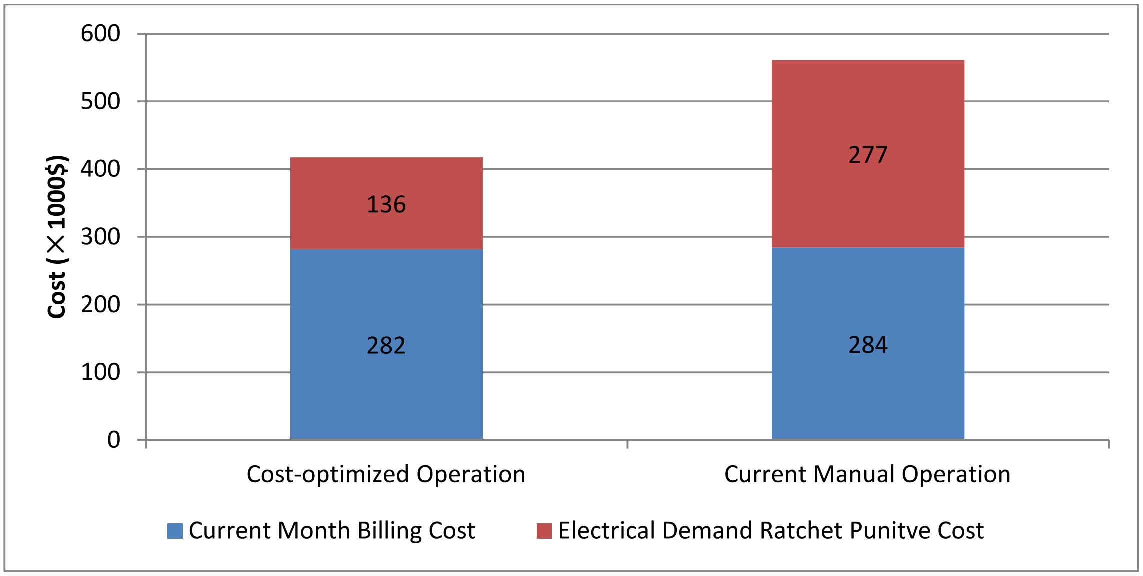

Figure 4.4 Comparison of monthly and total costs between simulated cost-optimized operation & actual manual operation

Because of the non-linear characteristic of the cost function, especially the demand cost and the demand ratchet punitive cost, the steam turbine chiller is more economical if the cooling load is greater than some threshold value. Shifting more or less cooling load both increases the total cost. The electric chiller is usually more economical than the steam turbine chiller under a simple cost rate, but as it is shown in Figure 4.3, shifting the cooling load from electric chiller to steam turbine results in a reduction in electrical energy cost of $20,000. However, the cooling load shifting increases the fuel cost by $29,000.

Determining the cooling load shifting point and the electrical demand limit are critical in achieving the lowest energy cost in summer months. By using more of the steam turbine chiller, the current month billing cost does not reduce significantly in August 2010. That is because as it is shown in Figure 4.3, the reduction of the electrical energy cost, electrical demand cost and electrical facility cost is not sensitive to the load shifting to the steam turbine chiller, but the fuel cost is. However, the total cost is greatly reduced by reducing the demand ratchet punitive cost significantly. Figure 4.4 indicates that the demand ratchet punitive cost is very sensitive to the load shifting to the steam turbine chiller, because the load shifting to the steam turbine chiller significantly reduces the peak electrical demand. A decrease of 700 kW of peak demand eventually results in a reduction of the demand ratchet punitive cost by half.

4.4 Simulated Cost-Optimized Operations Based on the Predicted Cooling Load[1]

In this section, the simulation of cost-optimized operation is generated using the predicted cooling load. The cooling load is predicted using the time series and multiple regression models. The cost of these operation profiles are compared with the actual cost and the cost under the perfect information of the cooling load (Section 4.3).

4.4.1 Cooling Load Forecasting Based on a Time Series Model

Based on the analysis of the cooling load data of August 2010, an auto-regression model is obtained through SAS® [35].

$$\begin{aligned} d_t &= 1.23711\, d_{t-1} - 0.10793\, d_{t-2} + 0.05339\, d_{t-3} \\ &\quad - 0.01545\, d_{t-4} - 0.08777\, d_{t-5} - 0.02061\, d_{t-6} \end{aligned} \qquad \text{Eq 30}$$

The forecasting results with different lead time are shown in Figure 4.5. Only the first 250 data points are shown in the graph.

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[1] Amey Patwardhan also worked for the forecasting.

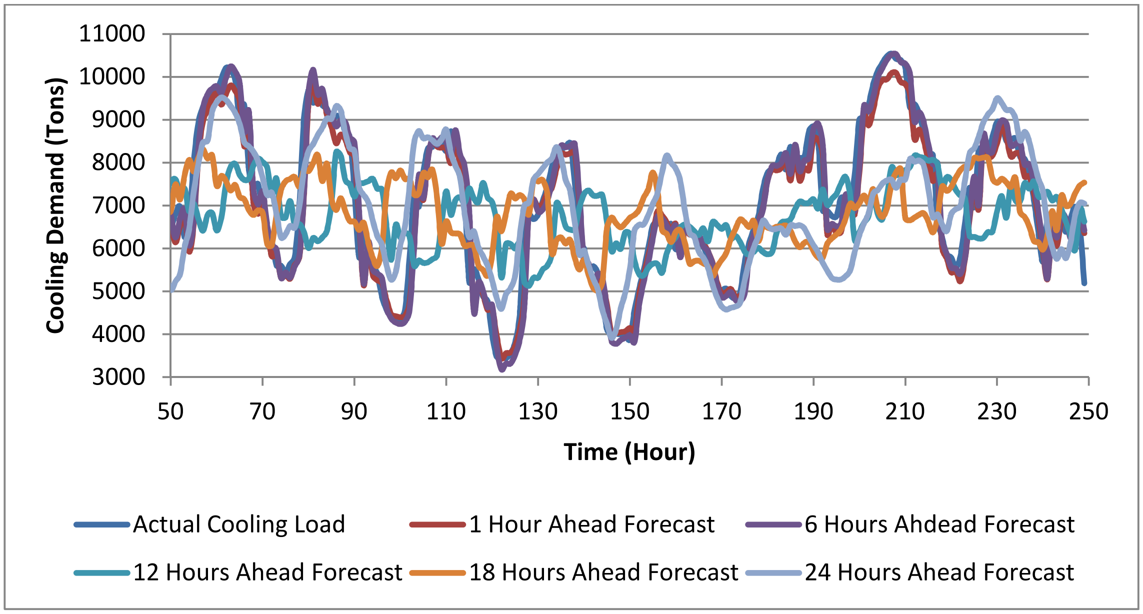

Figure 4.5 Cooling load forecasted by AR(6) model with different lead times

The one hour ahead forecasting result shows the best fitting. There is only little difference between the one-hour-ahead forecasting result and actual cooling load. The six hours ahead forecasting still gives good predictions, but with a less, however acceptable accuracy and lag. The 12 hours and 18 hours ahead forecasting result is far away from the actual demand with significant lag, due to the accumulating errors as the lead time increases. The 24 hours ahead forecasting result is better than the 12 hours and 18 hours ahead forecasting result.

4.4.2 Cooling Load Forecasting Based on Multiple Regression Model

In this research, a multiple regression model with independent variables of temperature and humidity is established based on the demand and weather data of August 2010. The regression model obtained through SAS® [35] is given as follows.

$$d_t = 1755 + 224 * temperature_t - 10 * humidity_t \qquad \text{Eq 31}$$

By using this model, cooling load is forecasted and compared with actual cooling load in the Figure 4.6.

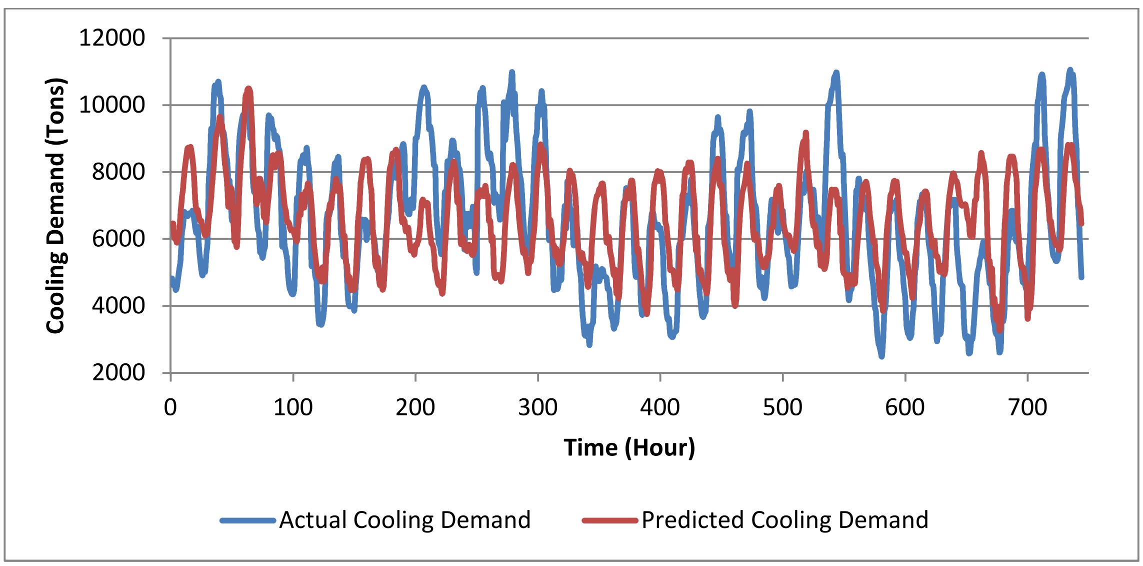

Figure 4.6 Cooling load forecasted by multiple regression model

The prediction does not show a satisfactory result. The R^2 of the regression model is 0.42, which means some important factors that affect the cooling load from the campus are not included. Out of 744 data points, there are 340 points of predicted cooling load which have a difference less than 1000 tons comparing to the actual values, and 403 points out of 744 which are greater than the actual values.

The multiple regression model fails to predict six critical peaks where the difference between the actual values and predicted values are greater than 1,000 tons. According to the discussion in Section 4.3.2, these peaks are critical to the demand cost and ratchet cost. The separate detailed analysis of the relevant data shows that these unpredicted peaks are usually caused by the uncertainty of building occupancy. For example, on-campus events are one of the factors that result in the uncertainty.

Although the model also fails to predict the some valleys, these are not critical to the total cost and it can be overcome by manual adjustment of the operation. The overestimation of the building occupancy and activity during the night time may have caused these unpredicted valleys. However, accurate prediction of these valleys would have saved the electrical energy cost.

4.4.3 Comparison of Error of Prediction between the Two Models

Figure 4.7 presents the comparison in term of root mean square errors of prediction for planning horizons length of zero to 24 hours between auto-regression model and multiple regression model. Because the load data follows a seasonal pattern of 24 hours, the error of prediction also shows a seasonal pattern. Compared with the simple regression model, the auto-regression model provides a more accurate prediction with a lead time less than 5 hours. As the error increases with the lead time, the multiple regression model has a better performance with a horizon length between 5 hours and 19 hours. Due to the seasonal pattern, the auto-regression model become better when the horizon length is between 19 to 29 hours. Thus a mixed model of auto-regression model and multiple regression model would have provided a good prediction within the proper horizon length according to the Figure 4.7.

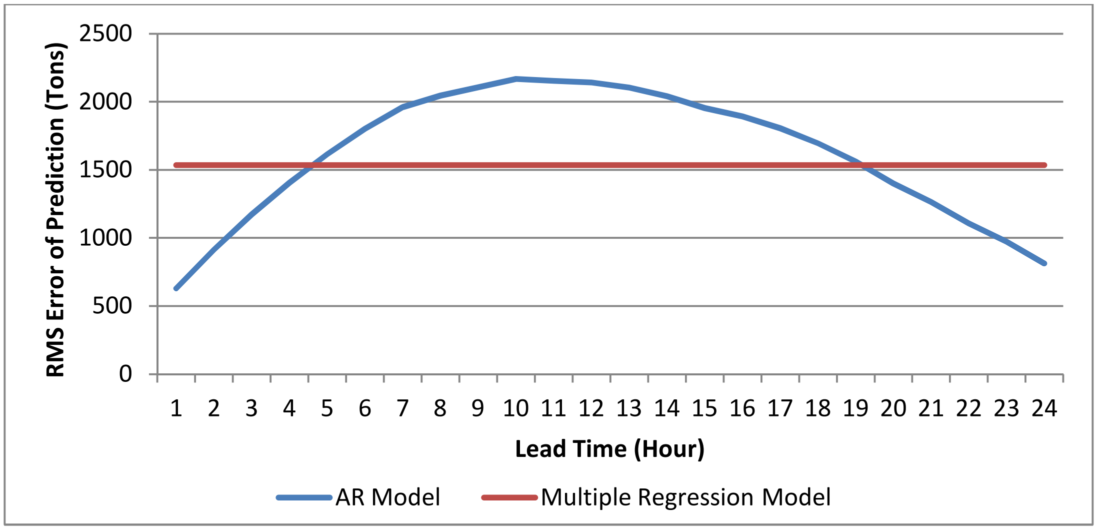

Figure 4.7 Root mean square errors of prediction for different lead time

4.4.4 Simulated Cost-optimized Operation Based on Cooling Load Predicted by Multiple Regression Model

Table 4.3 shows the energy usage and each individual cost terms of simulated cost-optimized operation based on the predicted cooling load through multiple regression model. In Table 4.3 the actual values and the values obtained through the simulation in Section 4.3.2 and are also listed for comparison.

Table 4.4 Simulated cost-optimized results & actual value

	Simulated Cost-optimized Operation Based on Predicted Cooing Demand	Simulated Cost-optimized Operation Based on Actual Demand	Actual Value
Total Cooling Load (kTons)	4,414	4,414	4,414
Total Electrical Energy (MWh)	4,400	4,445	4,929
Peak Electrical Demand (kW)	5,929	6,579	7,401
Total Fuel (MMbtu)	10,816	8,613	3,754
Electrical Energy Cost ($)	78,454	79,734	100,133
Electrical Demand Cost ($)	74,725	82,942	93,402
Electrical Facility Cost ($)	63,615	66,475	67,800
Fuel Cost ($)	65,764	52,366	22,824
Monthly Cost ($)	282,560	281,520	284,159
Demand Ratchet Punitive Cost ($)	97,444	135,810	276,976
Total Cost ($)	380,000	417,330	561,135

The total cooling loads produced are the same for the three cases. But because the multiple regression model fails to predict some critical peaks, the peak electrical demand of simulated cost-optimized operation based on the predicted cooling load through multiple regression model is lower than the value of simulated cost-optimized operation based on the actual cooling load. Therefore, it is more often that steam turbine chiller is operated to shift peak cooling load, as the maximum peak cooling load is lower. Thus the total cost is the lowest among the three cases. However, because there is only about half chance that the predicted cooling loads are greater than the actual cooling loads, the result does not well represent the actual situation.

4.5 Simulated Cost-Optimized Operations with Simple Conservative Strategy

In this section, a Monte Carlo simulation of cost-optimized operations based on the cooling load predicted by multiple regression model with random uncertainty is first conducted. The best and worst cases in term of total cost are compared with the actual operation and the cost-optimized operation under perfect information of cooling load.

A simple conservative strategy of cooling load forecasting is then introduced to buffer the impact of uncertainty in cooling load. The strategy is evaluated, by comparing to the actual operation and the cost-optimized operation obtained through the simulation in Section 4.3.2.

4.5.1 Monte Carlo Simulation for Evaluation of Uncertainty in Cooling Load

To evaluate the influence of uncertainty, a Monte Carlo simulation is conducted. The set of cooling loads is generated as follows:

$$d_t = 1755 + 224 * temperature_t - 10 * humidity_t + random_t(N(0,\sigma)) \quad \text{Eq 32}$$

where σ is the standard deviation of 744 data points of actual cooling load, which starts from 12:00 am August 1st 2010 to 12 am September 1st 2010 and measured by one hour interval.

Table 4.4 gives the best and worst simulation results in terms of the total cost among 100 trails.

Table 4.5 Monte Carlo simulation result

	Monte Carlo Simulation Result		Simulated Cost-optimized Operation Based on Actual Demand	Actual Value
	Best Case	Worst Case		
Total Cooling Load (kTons)	4,623	4,500	4,414	4,414
Total Electrical Energy (MWh)	4,490	4,690	4,445	4,929
Peak Electrical Demand (kW)	6,929	8,329	6,579	7,401
Total Fuel (MMbtu)	11,407	7,367	8,613	3,754
Electrical Energy Cost ($)	80,985	86,567	79,734	100,133
Electrical Demand Cost ($)	87,367	105,080	82,942	93,402
Electrical Facility Cost ($)	68,015	74,175	66,475	67,800
Fuel Cost ($)	69,356	44,790	52,366	22,824
Monthly Cost ($)	305,720	310,610	281,520	284,159
Demand Ratchet Punitive Cost ($)	159,260	264,980	135,810	276,976
Total Cost ($)	464,980	575.590	417,330	561,135

As discussed in Section 4.4.3, by using the multiple regression model, it is more likely that the cooling plant could make saving from shifting part of the peak cooling load from electric chillers to the steam turbine chiller. However, due to the uncertainty of the cooling load, the Monte Carlo simulation shows there is a chance that the operation of the cooling plant may cost more than the actual manual operation. Although in the worst case the steam turbine chiller is used more than actual operation, the cooling plant still hit its peak electrical demand of 8329 kW, which is 900kW higher than actual value. Because of the high cost in the current month, even if the demand ratchet punitive cost is little reduced comparing to the actual value, the cooling plant still needs to pay more in total. However, the best case provides an estimation of the peak electrical demand. The peak electrical demand in the best case is only 350kW higher than the value obtained through the simulated cost-optimized operation based on actual demand, which is within an acceptable range.

4.5.2 Simulations for Evaluation of a Simple Conservative Strategy

In order to buffer the impact of uncertainty and avoid those unpredicted peaks, a conservative strategy with different levels of safety factor is applied. By applying the simple conservative strategy, the cooling load is predicted as follows:

$$d_t = 1755 + 224 * temperature_t - 10 * humidity_t + z\sigma \qquad \text{Eq 33}$$

where z is the safety factor and σ was the same standard deviation of the actual cooling load using in Section 4.5.1.

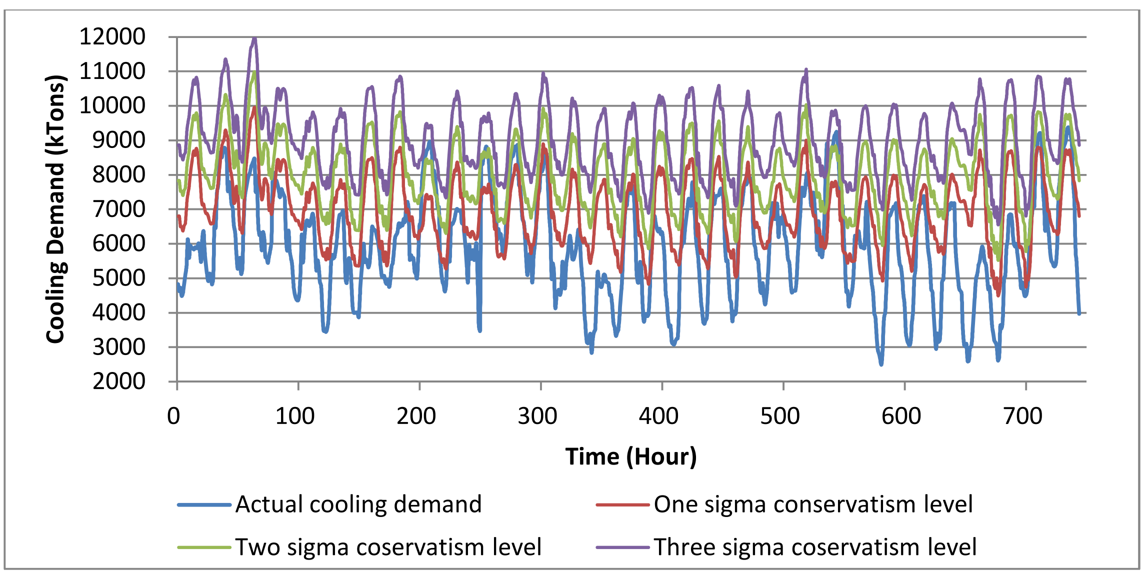

Figure 4.8 Predicted cooling load with different conservative level

As shown in the Figure 4.8, one sigma conservative level prediction does not improve much compared with the non-conservative prediction. It still does not cover some critical peaks. Two sigma conservative level prediction well coveres these peaks, while three sigma conservative level prediction is high than all the peaks.

The cost of simulated operation is given by Table 4.4.

Table 4.6 Simulated cost-optimized operation result based on cooling load forecasting with different level conservative levels

	Simulated Cost-optimized Operation Based on Conservative Cooling Load Forecasting			Simulated Cost-optimized Operation Based on Actual Demand
	One Sigma Conservative Level	Two Sigma Conservative Level	Three Sigma Conservative Level	
Total Cooling Load (kTons)	5,181	5,949	6,716	4,414
Total Electrical Energy (MWh)	5,107	6,106	6,853	4,445
Peak Electrical Demand (kW)	6,829	8,429	9,029	6,579
Total Fuel (MMbtu)	13,082	12,858	17,710	8,613
Electrical Energy Cost ($)	98,200	126,120	147,020	79,734
Electrical Demand Cost ($)	86,103	106,350	113,940	82,942
Electrical Facility Cost ($)	67,575	74,615	77,255	66,475
Fuel Cost ($)	79,536	78,140	107,680	52,366
Monthly Cost ($)	331,410	385,250	445,900	281,520
Demand Ratchet Punitive Cost ($)	152,560	273,380	325,210	135,810
Total Cost ($)	483,970	658,640	771,110	417,330
Number of Points Where the Predicted Cooling Load is Higher than Actual Value	610/744	730/744	744/744	378/744

Generally, the simple conservative prediction costs more. Although applying simple conservative strategy improves the number of points where the predicted cooling load is higher than actual value, as more production of cooling load is needed, more cost occurs. One sigma conservative level is the most cost efficient one. By applying one sigma conservative level, the number of points where the predicted cooling load is higher than actual value increases from 378 to 610, by 232, while the total cost is still lower than the actual total cost caused by the current manual operation of cooling plant in August 2010. Compared with one sigma conservative level, two and three sigma conservative levels cost much more than the actual total cost. However, one sigma conservative level still fails to predict some peaks, but two sigma conservative level provided a good prediction. On the other hand, the conservative strategy is not necessary for all peaks. As discussed in Section 4.4.2, because the prediction without conservative strategy has already well predicted most of the peaks, it is more appropriate that the conservative strategy is applied if there is a special event on campus which would lead to an unexpected high peak of cooling load. Meanwhile, different conservative levels should be applied based on the analysis of the event's impact on cooling load. Thus according to the Figure 4.7, one to two sigma might be a reasonable range of conservative level.

At the same time, the simple positive conservative strategy is not necessary for night time. As discussed in the Section 4.4.2, the valleys of cooling load during night time are not critical to the cost, and the influence of the difference can be avoided by manual adjustment. More importantly, these valleys of actual cooling load are more likely to be lower than the prediction without conservative strategy, so it is rational to have a negative conservative strategy for night time instead of a positive conservative strategy. According to the Figure 4.7, one to two sigma could also be a reasonable range of negative conservative level.

There is also a trend for high peaks or low valleys in the load profile. If there would be a high peak in a day which is much higher than the predicted peak, the actual cooling load tends to be much higher than the predicted load even at the low cooling load level in the same day. The same situation happens to the low valleys too. That is to say, if the actual cooling load in the early morning, for example 8 am to 11 am, is much high than the predicted cooling load, it is likely that there will be a high peak in that day.

CHAPTER 5

CONCLUSIONS

5.1 Summary and Contributions

This research introduced a general methodology for the cost-optimized operation of a hybrid central cooling plant. This research established a mixed integer non-linear program of the chiller operations, by integrating the complex characteristics of component efficiency, multiple energy sources, electrical energy cost, electrical demand cost, electrical ratchet cost, and energy consumption from other facilities. To reduce the required computation of the mixed integer non-linear program for real time implementation, a dual stage solution method was applied by introducing the electrical demand limit as a constraint. Through the case studies simulated based on the past operation and weather data, the methodology and mathematic model were also verified for their effectiveness. The case study result indicated a good potential saving in the total energy cost if the developed methodology was applied.

This study provides a generalized cost-optimized operation-planning model for a hybrid cooling plant under a complex cost structure. Although the detailed consideration of the utility cost structure is essential for optimal control of a cooling system [18], the majority of the existing research is based on the assumption that the cooling system is powered by a single electrical energy source, and the cooling system is considered as a separate system and charged separately from other facilities in the same organization. For example, for a hybrid cooling plant model by J.E. Braun [24], only time-of-use differentiated energy cost and demand cost were considered; the cooling plant was considered as an isolated system and powered by a single electrical energy source. Although in the model by J. Xu et al. [13] the 11-months ratchet cost was taken into consideration, the cooling system in their model was also a separate energy system from other facilities. In this research, in addition to the demand ratchet cost, the cooling plant's dual electrical energy sources—national and local suppliers were considered. In addition, this study considers that the electricity is delivered through primary and secondary services with a time-of-use differentiated cost rate. The electricity consumption from other facilities in the same organization is also taken into consideration. Therefore, the model in this research provides more generalized cost functions and enhances the cost-optimized operation decision for a hybrid cooling system.

5.2 Future Work

The first direction of future work is to improve the plant model and the cost-optimized operation planner for a more realistic practice by introducing more operation constraints. For example, because the weather condition will affect the performance of the cooling plant, the performance under different operation condition should be evaluated and the plant model considering the weather condition should be developed. In addition, constraint on the changes of the on-off status of chillers is a necessary, because it is not economic to change the on-off status of chillers too frequently. The frequent change will greatly reduce the reliability and lifetime of the equipment. These considerations are necessary for a more practical model.

The second direction of the future work is to develop a cost-optimized operation planning model with direct digit control technology. Thus a global control of a hybrid cooling system with multiple energy sources under complex electricity cost structure will be developed. In such a cooling system with direct digit control, the temperature of the cooled air will be adjusted by controlling the inflow rates of air and chilled water. More saving can be expected by implementing such a system. Thus, the development of the cost-optimized operation-scheduling model with a direct digit control technology will be one area of the future work.

The third direction of the future work could be the development of a sophisticated cooling load forecasting model combined with a proper conservative strategy and dynamics of cooling load. Because this research focuses more on a deterministic case of cooling load, the planning horizon can easily be set to be a billing period. However, in real time implementation it is not rational or feasible to provide a cooling load forecasting of the entire billing period. Ten days is usually the maximum time length for reliable weather forecasting, and thus the maximum time length for cooling load forecasting. Therefore, it is necessary to conduct a more sophisticated study on the dynamics of the cooling load.

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APPENDIX A

MAT LAB PROGRAM CODE

```
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alpha=0.65;
beta=0.415795;
gama=0.005;
a=[1 1 1 1 0 0 0 0 0 0 0 0;];
k=3;
T=744;
Y=[16002 16816 16537 15979 12278 9320  7715  7268  8885  8953  9029 11011;];

%% Actual number
%% e_pr=10217;
%% Average number
%% e_pr=9897;
 e_pr=[9291  9975 10436 10217  9732 10240  9581  8493  9070  9826  8335  8389;];

%% Actual number
 E_pr=5154251;
%% Average number
%% E_pr=4890099;

%% Actual number
 e_sc2=7858;
%% e_sc2=[6811 7963 7963 7753 6725 6437 6277 6413 6631 6982 7697 7025;];
%% Average number
%% e_sc2=7056;
```

```
%% Actual number
 E_sc2=3847282;
%% Average number
%% E_sc2=3503423;

e_w=[18740 18965 18965 18196 17745 14220 14015 14220 14220 14220 14220 17630;];
E_w=[9985000  9824000  10581000 9396000  8197000  7580000  7388000  7866000
7539000  7747000  7499000  8491000;];
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r=10919;
R=4400;
r_e_sc2=6400;

P_EC1=500;
P_EC2=450;
P_EC3=200;
P_EC4=200;
P_TC=250;

E_EC1=431.08;
E_EC2=302.99;
E_EC3=132.42;
E_EC4=132.42;
E_TC=2.8;
```

```
T_SU=3;

mintotalcost=10000000000000;

demand=zeros(1,T);

%% Actual demand
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10416 10387 10207 9288  9361  9146  8692  8197  8176  6707  6256  5869  5784  5547
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10677 10959 9735  10349 9426  8909  8425  7954  7767  7344  6563  5972  5557  5701
5710  5587  6414  6883  7340  8370  9002  9170  9946  9700  9961  10426 9950  9990
8957  7956  7325  5979  6536  6168  5404  4488  4583  4666  4510  4722  5477  4777
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3328 3422 3506 3936 4399 4928 5794 6595 7097 7102 7518 7473 7474 7464
7670 7240 6335 5190 4875 4880 5470 5270 4225 3748 3885 3959 3898 3973
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5688 5810 5604 5957 6843 8017 8901 9988 10033 10167 10444 10530 10825
10895 10973 10563 9686 8866 8452 8527 7567 6622 5671 4635 4177 4414 4505
4702 5182 6221 7434 7503 7813 7622 7301 7308 7212 7234 6868 7201 6273
5694 5263 4849 4589 3995 3849 3282 2916 2795 2622 2504 3006 3826 4008
4686 5661 6789 6809 6894 6994 7078 7023 7161 6334 5762 5397 5328 5007
4552 4235 3467 3209 3120 3046 3140 3688 4046 4986 5260 6492 6798 7120
7150 7345 7192 7379 6990 6699 5981 5675 5388 4668 4603 3991 3416 2947
3392 3153 3200 3860 4915 4960 5697 6282 6838 7122 6991 7154 7179 7098
7170 5917 5406 5008 4697 4631 4564 3543 3081 3022 3092 2590 2611 2984
3017 3392 3930 4524 4992 5130 5381 5503 5751 5919 5774 5486 5402 5087
4677 4749 4324 3666 3420 3189 3131 3018 2612 2704 3629 3543 3790 4999
5058 5874 6096 6800 6849 6835 6441 6030 5920 5990 5704 5400 5200 4713
4881 4640 4484 4495 5624 6148 7504 8079 8421 8829 8667 9989 10232 10595
10866 10915 10616 9165 8495 7583 7217 6588 6240 5769 5504 5447 5349 5351
5468 6079 8900 9322 9724 10211 10348 10465 10605 10959 11054 10753 10912
10417 9251 8644 7179 6602 5700 4853;];

```
%% tf=[71 68 66 68 64 66 72 77 81 84 84 87 88 89 89 88 87 85 84 83 82 80 80 79 77 76
76 76 75 75 75 77 81 83 86 87 90 92 93 93 93 90 87 85 84 79 79 78 78 78 77 75 73 73 76
80 82 83 85 88 88 90 90 89 87 86 85 82 81 79 78 79 77 78 76 76 75 75 76 76 77 76 78 81
84 85 86 87 87 85 82 77 76 74 75 70 71 69 68 69 67 67 70 76 79 82 85 84 86 86 84 85 84
81 79 76 75 74 72 69 68 69 67 66 68 68 71 71 76 79 81 84 85 86 86 85 86 85 83 78 77 75
73 73 71 69 68 69 70 69 73 76 79 83 86 88 90 91 91 91 91 89 87 82 81 79 78 79 78 78 78
77 77 75 78 82 84 88 91 92 95 95 96 98 98 96 94 90 86 83 78 78 75 75 74 73 73 73 74 75
82 87 90 93 94 94 94 95 94 94 88 85 83 82 81 81 80 78 77 76 76 75 80 84 86 88 89 91 93
93 94 96 94 94 91 88 82 79 79 76 77 75 74 74 71 72 75 78 83 87 91 93 95 97 97 99 99 97
94 87 85 80 76 80 76 75 73 72 68 69 75 80 83 87 90 93 95 97 99 100 99 95 95 90 85 83
79 78 82 78 75 78 73 73 76 78 82 83 87 89 89 92 93 93 95 90 86 81 78 75 72 70 72 68 66
64 64 63 68 73 75 80 83 85 88 90 87 89 86 85 78 74 71 70 68 66 67 66 64 64 58 58 64 70
77 76 80 81 83 85 85 85 84 83 77 70 68 68 63 62 63 62 62 61 62 59 64 70 77 82 84 85 87
88 89 87 85 83 81 76 72 69 70 68 68 68 67 68 67 67 67 66 66 66 65 66 67 67 67 68 66 66
66 65 65 64 65 65 65 65 65 65 66 66 66 67 68 69 72 74 78 81 82 83 83 82 78 75 70 73 70
69 68 70 69 66 65 65 68 73 79 83 87 88 91 93 90 90 89 88 86 83 81 79 78 78 73 76 75 75
73 73 72 73 76 79 82 83 86 88 85 87 86 89 85 81 78 77 74 73 72 70 71 71 70 69 71 76 81
85 88 89 90 92 94 94 93 90 84 79 78 76 72 71 71 69 70 66 66 67 70 74 80 85 88 90 91 93
93 93 92 90 87 83 82 78 74 72 70 70 68 69 67 70 72 76 80 84 87 90 92 92 93 93 92 89 87
83 82 82 73 67 66 66 66 66 66 66 66 68 69 71 74 76 79 81 80 80 79 77 70 67 65 60 58 57
54 55 55 52 53 54 57 64 71 76 80 81 81 83 83 84 83 81 79 74 71 70 65 64 63 61 60 60 58
58 61 65 71 78 81 84 86 87 87 86 85 82 76 70 67 64 62 63 61 65 61 57 56 54 60 68 74 78
82 83 85 86 87 86 85 83 76 69 65 65 66 66 64 63 62 60 58 59 62 71 76 81 84 88 89 91 91
90 89 86 81 78 75 74 73 71 69 68 66 68 64 64 68 74 80 83 87 90 91 93 93 90 89 88 86 83
81 80 78 76 75 75 75 75 75 74 74 77 81 84 87 89 91 93 93 93 92 89 86 83 82 81 81 80 80
79 79 79 78 78 79 81 84 86 89 88 90 93 92 92 84 80 77 74 73 70 69 69;];

%% Predicted demand
%% for i=1:1:T
%%     demand(1,i)=161.72*tf(1,i)-6081;
```

```
%% end

%% Predicted demand plus one SD
%% for i=1:1:T
%%     demand(1,i)=161.72*tf(1,i)-6081+1264;
%% end

%% Predicted demand plus two SDs
%% for i=1:1:T
%%     demand(1,i)=161.72*tf(1,i)-6081+2*1264;
%% end

%% Predicted demand plus three SDs
%% for i=1:1:T
%%     demand(1,i)=161.72*tf(1,i)-6081+3*1264;
%% end

%% Monte Carlo Simulation
%% actualdemand=[4827  4624  4716  4483  4574  4838  5119  5381  6131  6385  6807
6747  6699  6690  6768  6764  6783  6848  6613  6326  6174  6360  5776  5385  5071
4913  5132  5027  5522  5953  7721  8272  9291  8996  10087 10587 10406 10582 10694
10310 10157 9114  9204  9002  8542  8340  7751  7746  7066  6556  6793  6967  6259
6656  8035  8935  9292  9527  9711  9653  9948  10205 10158 9946  9018  9332  7832
7413  7496  6875  6328  6172  5605  5598  5441  5635  5808  7003  9028  9692  9393
9607  9339  9256  8985  9092  9025  8727  8592  7330  5797  6382  5818  5606  5397
4870  4570  4433  4363  4357  4554  5760  7214  6967  7775  8326  8364  8505  8495
8274  8730  8317  8069  7173  5221  5517  5288  4881  4763  3987  3474  3477  3443
3548  3815  4444  6387  6770  6680  6789  7100  7426  7889  8254  8302  8371  8449
7514  6187  5996  5481  5584  5424  4820  4121  3993  4004  3995  3998  3877  4548
5051  5491  6001  6532  6594  6528  6395  6563  5974  6491  6421  6397  6348  6172
6038  5775  5340  5056  5025  5063  4887  4836  4960  5670  6133  6450  6761  7390
```

7762 7842 7947 8187 7838 8370 7910 8107 8125 8725 8840 8520 6885 6875
6754 6745 7175 7088 6946 7759 9007 9023 9344 9819 10129 10318 10475 10537
10416 10387 10207 9288 9361 9146 8692 8197 8176 6707 6256 5869 5784 5547
5808 6585 7413 6971 8313 8168 8249 8605 8945 8905 8508 8532 8557 8132
8081 7710 7137 6373 5690 6734 6346 6749 6660 6385 6695 6971 6529 5186
5011 9964 10003 10381 10347 10508 10047 9739 9032 8534 8396 8558 8258 8127
7111 7355 7240 7270 6910 6580 6835 7270 10048 8987 9269 9857 10239 10394
10677 10959 9735 10349 9426 8909 8425 7954 7767 7344 6563 5972 5557 5701
5710 5587 6414 6883 7340 8370 9002 9170 9946 9700 9961 10426 9950 9990
8957 7956 7325 5979 6536 6168 5404 4488 4583 4666 4510 4722 5477 4777
5793 6476 6997 6321 7705 7488 6986 6876 6697 5828 6121 6406 6323 5645
5092 4854 4011 3552 3150 3111 3191 3381 2833 3259 3440 3526 4530 5180
4885 4787 4740 4849 5100 5085 4900 4880 4840 4510 4510 4180 3697 3571
3328 3422 3506 3936 4399 4928 5794 6595 7097 7102 7518 7473 7474 7464
7670 7240 6335 5190 4875 4880 5470 5270 4225 3748 3885 3959 3898 3973
4676 6208 6460 6767 6799 6565 6423 6351 6437 6278 6331 6071 5654 4599
4325 3817 3586 3625 3150 3093 3075 3180 3239 3260 4038 5720 5891 6046
6025 6426 6744 7040 7302 7112 7092 7771 7505 6801 6162 5831 5524 4967
4408 4090 3730 3675 3775 3860 4700 6330 6464 6804 7466 8764 9157 9113
9262 9646 9212 9276 9066 8429 7269 6734 6678 5881 5657 5426 4846 5127
5165 5234 6064 8083 8025 8295 8450 8860 9181 9130 9198 9436 9419 9819
9385 7959 7252 7031 6960 6474 5196 4653 4566 4861 4441 4235 4448 4854
5526 6317 6795 7177 6956 6712 6879 7139 6197 6669 6753 6582 6848 6290
6161 5864 5533 5440 4923 4587 4628 4632 4642 4949 5692 6280 6872 7617
7618 7379 7548 7933 8055 7810 7570 7092 7297 7475 7018 6467 5811 6653
5688 5810 5604 5957 6843 8017 8901 9988 10033 10167 10444 10530 10825
10895 10973 10563 9686 8866 8452 8527 7567 6622 5671 4635 4177 4414 4505
4702 5182 6221 7434 7503 7813 7622 7301 7308 7212 7234 6868 7201 6273
5694 5263 4849 4589 3995 3849 3282 2916 2795 2622 2504 3006 3826 4008
4686 5661 6789 6809 6894 6994 7078 7023 7161 6334 5762 5397 5328 5007
4552 4235 3467 3209 3120 3046 3140 3688 4046 4986 5260 6492 6798 7120

```
7150  7345  7192  7379  6990  6699  5981  5675  5388  4668  4603  3991  3416  2947
3392  3153  3200  3860  4915  4960  5697  6282  6838  7122  6991  7154  7179  7098
7170  5917  5406  5008  4697  4631  4564  3543  3081  3022  3092  2590  2611  2984
3017  3392  3930  4524  4992  5130  5381  5503  5751  5919  5774  5486  5402  5087
4677  4749  4324  3666  3420  3189  3131  3018  2612  2704  3629  3543  3790  4999
5058  5874  6096  6800  6849  6835  6441  6030  5920  5990  5704  5400  5200  4713
4881  4640  4484  4495  5624  6148  7504  8079  8421  8829  8667  9989  10232 10595
10866 10915 10616 9165  8495  7583  7217  6588  6240  5769  5504  5447  5349  5351
5468  6079  8900  9322  9724  10211 10348 10465 10605 10959 11054 10753 10912
10417 9251  8644  7179  6602  5700  4853;];
%% expectdemand=161.72*tf-6081;
%% maxsimucost=0;
%% minsimucost=1000000;
%% for x=1:1:50
%%     demand=zeros(1,T);
%%     randomdemand=normrnd(0,1264,1,T);
%%     demand=expectdemand+randomdemand;

for y=7200:50:7600
%%for y=r_e_sc2:200:12000
%%for y=r_e_sc2:400:18400
    tempoperation=zeros(5,T);
    judge=1;
    totalenergy=0;
    totalgas=0;
    startup=0;
    for t=1:1:T
        hourlygas=0;
        if judge==0
            break
        end
```

```
minhourlyenergy=100000000000;
maxsupply_ec=0;
for ec1=0:1:10
    for ec2=0:1:10
        for ec3=0:1:10
            for ec4=0:1:10
                if ec1<5
                    partload(1,1)=0;
                else
                    partload(1,1)=ec1;
                end
                if ec2<5
                    partload(2,1)=0;
                else
                    partload(2,1)=ec2;
                end
                if ec3<5
                    partload(3,1)=0;
                else
                    partload(3,1)=ec3;
                end
                if ec4<5
                    partload(4,1)=0;
                else
                    partload(4,1)=ec4;
                end
                E_se=0;
                if demand(1,t)>0.1 && demand(1,t)<2000.1
                    E_se=946.6;
                end
                if demand(1,t)>2000.1 && demand(1,t)<4000.1
```

```
E_se=1127.6;
end
if demand(1,t)>4000.1 && demand(1,t)<4500.1
   E_se=1530.1;
end
if demand(1,t)>4500.1 && demand(1,t)<6500.1
   E_se=1847.8;
end
if demand(1,t)>6500.1 && demand(1,t)<8500.1
   E_se=2086.4;
end
if demand(1,t)>8500.1 && demand(1,t)<9000.1
   E_se=2852;
end
if demand(1,t)>9000.1 && demand(1,t)<9500.1
   E_se=2993.8;
end
if demand(1,t)>9500.1 && demand(1,t)<11500.1
   E_se=3174.8;
end
if demand(1,t)>11500.1 && demand(1,t)<13500.1
   E_se=3940.4;
end

E_ec=E_EC1*partload(1,1)+E_EC2*partload(2,1)+E_EC3*partload(3,1)+E_EC4*partlo
ad(4,1);
if E_ec+E_se<y

supply_ec=P_EC1*partload(1,1)+P_EC2*partload(2,1)+P_EC3*partload(3,1)+P_EC4*p
artload(4,1);
   if supply_ec<demand(1,t)
```

```
if partload(4,1)==10
    if partload(3,1)==10
        if partload(2,1)==10
            if partload(1,1)==10
                for tc=0:1:20
                    if tc<5
                        partload(5,1)=0;
                    else
                        partload(5,1)=tc;
                    end
                    supply_tc=P_TC*partload(5,1);
                    if supply_tc>demand(1,t)-supply_ec
                        for i=1:1:5
                            tempopeation(i,t)=partload(i,1);
                        end
                        hourlyenergy=E_se+E_ec;
                        minhourlyenergy=hourlyenergy;
                        hourlygas=E_TC*partload(5,1);
                        break
                    end
                end
            else
                adjustpartload=partload(1,1)+1;

adjust_E_ec=E_EC1*adjustpartload+E_EC2*partload(2,1)+E_EC3*partload(3,1)+E_EC
4*partload(4,1);
                if adjust_E_ec+E_se>y
                    if supply_ec>maxsupply_ec
                        if demand(1,t)-supply_ec>20*P_TC
                            hourlyenergy=1000000000;
                        else
```

```
                        maxsupply_ec=supply_ec;
                        for tc=0:1:20
                          if tc<5
                            partload(5,1)=0;
                          else
                            partload(5,1)=tc;
                          end
                          supply_tc=P_TC*partload(5,1);
                          if supply_tc>demand(1,t)-supply_ec
                            hourlyenergy=E_se+E_ec;
                            if hourlyenergy<minhourlyenergy
                              for i=1:1:5
                                tempoperation(i,t)=partload(i,1);
                              end
                              minhourlyenergy=hourlyenergy;
                              hourlygas=E_TC*partload(5,1);
                            end
                            break
                          end
                        end
                      end
                    end
                  else
                    hourlyenergy=1000000000;
                  end
                end
              else
                adjustpartload=partload(2,1)+1;

adjust_E_ec=E_EC1*partload(1,1)+E_EC2*adjustpartload+E_EC3*partload(3,1)+E_EC
4*partload(4,1);
```

```
    if adjust_E_ec+E_se>y
        if supply_ec>maxsupply_ec
            if demand(1,t)-supply_ec>20*P_TC
                hourlyenergy=1000000000;
            else
                maxsupply_ec=supply_ec;
                for tc=0:1:20
                    if tc<5
                        partload(5,1)=0;
                    else
                        partload(5,1)=tc;
                    end
                    supply_tc=P_TC*partload(5,1);
                    if supply_tc>demand(1,t)-supply_ec
                        hourlyenergy=E_se+E_ec;
                        if hourlyenergy<minhourlyenergy
                            for i=1:1:5
                                tempoperation(i,t)=partload(i,1);
                            end
                            minhourlyenergy=hourlyenergy;
                            hourlygas=E_TC*partload(5,1);
                        end
                        break
                    end
                end
            end
        end
    else
        hourlyenergy=1000000000;
    end
end
```

```
                    else
                       adjustpartload=partload(3,1)+1;

adjust_E_ec=E_EC1*partload(1,1)+E_EC2*partload(2,1)+E_EC3*adjustpartload+E_EC
4*partload(4,1);
                       if adjust_E_ec+E_se>y
                          if supply_ec>maxsupply_ec
                             if demand(1,t)-supply_ec>20*P_TC
                                hourlyenergy=1000000000;
                             else
                                maxsupply_ec=supply_ec;
                                for tc=0:1:20
                                   if tc<5
                                      partload(5,1)=0;
                                   else
                                      partload(5,1)=tc;
                                   end
                                   supply_tc=P_TC*partload(5,1);
                                   if supply_tc>demand(1,t)-supply_ec
                                      hourlyenergy=E_se+E_ec;
                                      if hourlyenergy<minhourlyenergy
                                         for i=1:1:5
                                            tempoperation(i,t)=partload(i,1);
                                         end
                                         minhourlyenergy=hourlyenergy;
                                         hourlygas=E_TC*partload(5,1);
                                      end
                                      break
                                   end
                                end
                             end
```

```
                    end
                else
                    hourlyenergy=1000000000;
                end
            end
        else
            adjustpartload=partload(4,1)+1;

adjust_E_ec=E_EC1*partload(1,1)+E_EC2*partload(2,1)+E_EC3*partload(3,1)+E_EC4
*adjustpartload;
            if adjust_E_ec+E_se>y
                if supply_ec>maxsupply_ec
                    if demand(1,t)-supply_ec>20*P_TC
                        hourlyenergy=1000000000;
                    else
                        maxsupply_ec=supply_ec;
                        for tc=0:1:20
                            if tc<5
                                partload(5,1)=0;
                            else
                                partload(5,1)=tc;
                            end
                            supply_tc=P_TC*partload(5,1);
                            if supply_tc>demand(1,t)-supply_ec
                                hourlyenergy=E_se+E_ec;
                                if hourlyenergy<minhourlyenergy
                                    for i=1:1:5
                                        tempoperation(i,t)=partload(i,1);
                                    end
                                    minhourlyenergy=hourlyenergy;
                                    hourlygas=E_TC*partload(5,1);
```

```
                        end
                        break
                    end
                end
            end
        end
      else
        hourlyenergy=1000000000;
      end
    end
  else
    hourlyenergy=E_se+E_ec;
    if hourlyenergy<minhourlyenergy
      minhourlyenergy=hourlyenergy;
      for i=1:1:4
        tempoperation(i,t)=partload(i,1);
      end
      tempoperation(5,t)=0;
    end
  end
else
  hourlyenergy=1000000000000;
end
end
end
end
end
if minhourlyenergy>1000000000
  judge=0*judge;
else
  totalgas=totalgas+hourlygas;
```

```
        totalenergy=totalenergy+minhourlyenergy;
      end
    end
    if judge==1
      for i=2:1:T
        if tempoperation(5,i-1)==0 && tempoperation(5,i)>1
          startup=startup+10*E_TC*T_SU;
        end
      end
      totalgas=totalgas+startup;
      totalcost=0;

cost_energy1=c_eg_pr_l(1,k)*(E_pr/(E_pr+totalenergy+E_sc2))*(E_pr+totalenergy+E_s
c2-E_w(1,k));

cost_energy2=c_eg_sc_l(1,k)*((E_sc2+totalenergy)/(E_pr+totalenergy+E_sc2))*(E_pr+t
otalenergy+E_sc2-E_w(1,k));
      cost_energy=cost_energy1+cost_energy2;
      cost_fuel=c_f*totalgas;
      if e_pr(1,k)+y+e_sc2-e_w(1,k)>R

cost_demand=c_dm_pr_l(1,k)*(e_pr(1,k)/(e_pr(1,k)+y+e_sc2))*(e_pr(1,k)+y+e_sc2-
e_w(1,k))+c_dm_sc_l(1,k)*((e_sc2+y)/(e_pr(1,k)+y+e_sc2))*(e_pr(1,k)+y+e_sc2-
e_w(1,k));
      else

cost_demand=c_dm_pr_l(1,k)*(e_pr(1,k)/(e_pr(1,k)+y+e_sc2))*R+c_dm_sc_l(1,k)*((e_s
c2+y)/(e_pr(1,k)+y+e_sc2))*R;
      end
      if e_sc2+y>r
        cost_facility=c_fc(1,k)*(y+e_sc2);
```

```
else
   cost_facility=c_fc(1,k)*r;
end
cost_punitive=0;
K=k+1;
for i=K:1:12
   if alpha*(e_pr(1,k)+y+e_sc2-e_w(1,k))-(e_pr(1,i)+Y(1,i)-e_w(1,i))>0
      delta_e=alpha*(e_pr(1,k)+y+e_sc2-e_w(1,k))-(e_pr(1,i)+Y(1,i)-e_w(1,i));
   else
      delta_e=0;
   end
   if alpha*(y+e_sc2)-Y(1,i)>0
      delta_Y=alpha*(y+e_sc2)-Y(1,i);
   else
      delta_Y=0;
   end
   %%
cost_punitive=cost_punitive+a(1,k)*(c_dm_pr_l(1,i)*delta_e*(e_pr(1,i)/(e_pr(1,i)+Y(1,i)
))+c_dm_sc_l(1,i)*delta_e*((Y(1,i))/(e_pr(1,i)+Y(1,i)))+c_fc(1,i)*delta_Y);

cost_punitive=cost_punitive+a(1,k)*(c_dm_pr_l(1,i)*delta_e*(e_pr(1,i)/(e_pr(1,i)+Y(1,i)
))+c_dm_sc_l(1,i)*delta_e*((Y(1,i))/(e_pr(1,i)+Y(1,i)))+c_fc(1,i)*delta_Y)/((1+gama)^(i
-k));
end
totalcost=cost_energy+cost_demand+cost_facility+cost_fuel+cost_punitive;
monthlycost=cost_energy+cost_demand+cost_facility+cost_fuel;
if totalcost<mintotalcost
   energycost=cost_energy;
   demandcost=cost_demand;
   facilitycost=cost_facility;
   punitivecost=cost_punitive;
```

```
            fuelcost=cost_fuel;
            Yy=y;
            mintotalcost=totalcost;
            MonthlyCost=monthlycost;
            operation=tempoperation;
            TotalEnergy=totalenergy;
            PeakDemand=y+e_pr(1,k)+e_sc2-e_w(1,k);
            TotalFuel=totalgas;
        end
        tempmincost=10000000000000000;
    end
    if totalgas==0
        break
    end
end
Operation=operation
Yy=Yy
TotalEnergy=TotalEnergy
PeakDemand=PeakDemand
TotalFuel=TotalFuel
EnergyCost=energycost
DemandCost=demandcost
FacilityCost=facilitycost
PunitiveCost=punitivecost
FuelCost=fuelcost
MonthlyCost=MonthlyCost
MinTotalCost=mintotalcost

%% if MinTotalCost<minsimucost
%%    minsimucost=MinTotalCost;
%%    minsimu_Operation=Operation;
```

```
%%    minsimu_Y=Yy;
%%    minsimu_TotalEnergy=TotalEnergy;
%%    minsimu_PeakDemand=PeakDemand;
%%    minsimu_TotalFuel=TotalFuel;
%%    minsimu_EnergyCost=EnergyCost;
%%    minsimu_DemandCost=DemandCost;
%%    minsimu_FacilityCost=FacilityCost;
%%    minsimu_PunitiveCost=PunitiveCost;
%%    minsimu_FuelCost=FuelCost;
%%    minsimu_MonthlyCost=MonthlyCost;
%%    minsimu_TotalCost=MinTotalCost;
%%    NoAccuracy=0;
%%    for i=1:1:T
%%        if actualdemand(1,i)>demand(1,i)
%%            NoAccuracy=NoAccuracy+1;
%%        end
%%    end
%%    mindemand=demand;
%%    minsimu_Accuracy=NoAccuracy;
%% end

%% if MinTotalCost>maxsimucost
%%    maxsimucost=MinTotalCost;
%%    maxsimu_Operation=Operation;
%%    maxsimu_Y=Yy;
%%    maxsimu_TotalEnergy=TotalEnergy;
%%    maxsimu_PeakDemand=PeakDemand;
%%    maxsimu_TotalFuel=TotalFuel;
%%    maxsimu_EnergyCost=EnergyCost;
%%    maxsimu_DemandCost=DemandCost;
%%    maxsimu_FacilityCost=FacilityCost;
```

```
%%    maxsimu_PunitiveCost=PunitiveCost;
%%    maxsimu_FuelCost=FuelCost;
%%    maxsimu_MonthlyCost=MonthlyCost;
%%    maxsimu_TotalCost=MinTotalCost;
%%    NoAccuracy=0;
%%    for i=1:1:T
%%        if actualdemand(1,i)>demand(1,i)
%%            NoAccuracy=NoAccuracy+1;
%%        end
%%    end
%%    maxdemand=demand;
%%    maxsimu_Accuracy=NoAccuracy;
%% end
%% end

%%    minsimu_Operation=minsimu_Operation;
%%    minsimu_Y=minsimu_Y
%%    minsimu_TotalEnergy=minsimu_TotalEnergy
%%    minsimu_PeakDemand=minsimu_PeakDemand
%%    minsimu_TotalFuel=minsimu_TotalFuel
%%    minsimu_EnergyCost=minsimu_EnergyCost
%%    minsimu_DemandCost=minsimu_DemandCost
%%    minsimu_FacilityCost=minsimu_FacilityCost
%%    minsimu_PunitiveCost=minsimu_PunitiveCost
%%    minsimu_FuelCost=minsimu_FuelCost
%%    minsimu_MonthlyCost=minsimu_MonthlyCost
%%    minsimu_TotalCost=minsimu_TotalCost
%%    minsimu_Accuracy=minsimu_Accuracy
%%    mindemand=mindemand

%%    maxsimu_Operation=maxsimu_Operation;
```

```
%%    maxsimu_Y=maxsimu_Y
%%    maxsimu_TotalEnergy=maxsimu_TotalEnergy
%%    maxsimu_PeakDemand=maxsimu_PeakDemand
%%    maxsimu_TotalFuel=maxsimu_TotalFuel
%%    maxsimu_EnergyCost=maxsimu_EnergyCost
%%    maxsimu_DemandCost=maxsimu_DemandCost
%%    maxsimu_FacilityCost=maxsimu_FacilityCost
%%    maxsimu_PunitiveCost=maxsimu_PunitiveCost
%%    maxsimu_FuelCost=maxsimu_FuelCost
%%    maxsimu_MonthlyCost=maxsimu_MonthlyCost
%%    maxsimu_TotalCost=maxsimu_TotalCost
%%    maxsimu_Accuracy=maxsimu_Accuracy
%%    maxdemand=maxdemand

 %% r=normrnd(0,1078.754);
```

APPENDIX B

COOLING LOAD AND WEATHER DATA

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
1	4827	24.4	22.6	373	7473	27.2	22.5
2	4624	24.4	22.6	374	7474	26.1	21.7
3	4716	22.8	21.6	375	7464	26.7	22.1
4	4483	22.8	21.6	376	7670	28.3	23.0
5	4574	22.2	21.3	377	7240	28.3	23.1
6	4838	22.8	21.5	378	6335	26.7	22.0
7	5119	23.3	21.9	379	5190	24.4	20.8
8	5381	25.6	23.0	380	4875	22.2	19.7
9	6131	27.2	24.0	381	4880	20.0	18.6
10	6385	28.3	24.6	382	5470	20.6	19.2
11	6807	30.0	25.6	383	5270	18.9	18.1
12	6747	31.1	25.8	384	4225	17.8	17.4
13	6699	32.2	26.4	385	3748	16.1	16.5
14	6690	32.8	26.5	386	3885	15.6	16.2
15	6768	31.7	25.5	387	3959	13.9	15.1
16	6764	32.8	26.2	388	3898	13.9	15.1
17	6783	32.2	26.0	389	3973	12.8	14.3
18	6848	31.1	25.6	390	4676	14.4	15.3
19	6613	29.4	24.8	391	6208	16.1	16.6
20	6326	26.7	23.4	392	6460	18.3	17.8
21	6174	25.6	22.9	393	6767	22.8	20.7
22	6360	25.6	22.8	394	6799	26.1	22.4
23	5776	25.0	22.6	395	6565	27.8	22.8
24	5385	24.4	22.3	396	6423	28.3	23.1
25	5071	24.4	22.3	397	6351	28.9	23.3
26	4913	23.9	22.0	398	6437	29.4	23.6
27	5132	23.3	21.6	399	6278	28.3	23.1
28	5027	22.8	21.3	400	6331	29.4	23.8
29	5522	22.8	21.2	401	6071	28.9	23.4
30	5953	22.8	21.2	402	5654	28.3	23.2
31	7721	24.4	22.0	403	4599	26.7	22.5
32	8272	25.6	22.9	404	4325	23.9	21.1
33	9291	27.3	24.1	405	3817	23.3	20.9
34	8996	29.4	25.6	406	3586	21.7	20.0
35	10087	31.1	26.7	407	3625	20.6	19.4
36	10587	33.3	28.1	408	3150	18.3	18.1

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
37	10406	35.0	29.2	409	3093	18.3	18.0
38	10582	35.6	29.5	410	3075	18.3	18.0
39	10694	36.1	29.8	411	3180	17.8	17.7
40	10310	37.2	30.3	412	3239	16.7	17.1
41	10157	36.7	30.1	413	3260	16.7	17.1
42	9114	36.1	29.7	414	4038	16.1	16.7
43	9204	33.9	28.5	415	5720	17.2	17.4
44	9002	32.2	27.9	416	5891	20.0	19.2
45	8542	31.1	27.2	417	6046	23.9	21.5
46	8340	29.4	26.1	418	6025	27.2	23.6
47	7751	26.7	24.3	419	6426	27.2	23.0
48	7746	26.7	24.1	420	6744	29.4	24.0
49	7066	28.3	24.5	421	7040	30.0	24.3
50	6556	27.8	24.1	422	7302	29.4	23.8
51	6793	25.0	22.6	423	7112	30.6	24.4
52	6967	22.2	21.0	424	7092	30.6	24.4
53	6259	22.2	21.0	425	7771	30.6	24.3
54	6656	21.7	20.8	426	7505	29.4	23.8
55	8035	24.4	22.5	427	6801	27.2	23.0
56	8935	28.3	24.6	428	6162	25.6	22.1
57	9292	31.1	26.2	429	5831	20.6	19.5
58	9527	32.8	27.1	430	5524	22.2	20.4
59	9711	34.4	28.1	431	4967	18.9	18.4
60	9653	36.7	29.4	432	4408	17.8	17.7
61	9948	37.8	29.7	433	4090	18.3	18.0
62	10205	38.3	30.2	434	3730	17.2	17.4
63	10158	38.9	30.4	435	3675	17.2	17.5
64	9946	38.9	29.9	436	3775	16.7	17.1
65	9018	38.3	29.8	437	3860	16.1	16.7
66	9332	36.7	29.2	438	4700	15.6	16.4
67	7832	33.3	27.5	439	6330	17.2	17.5
68	7413	29.4	25.4	440	6464	20.6	19.6
69	7496	28.3	24.8	441	6804	23.9	21.2
70	6875	26.7	23.9	442	7466	26.7	22.7
71	6328	27.2	24.1	443	8764	28.3	23.4
72	6172	29.4	25.2	444	9157	29.4	24.0
73	5605	29.4	25.1	445	9113	30.0	24.2
74	5598	28.9	24.8	446	9262	30.6	24.5
75	5441	28.3	24.5	447	9646	31.1	24.8
76	5635	25.0	22.7	448	9212	28.3	23.3
77	5808	25.6	22.9	449	9276	27.8	23.0
78	7003	24.4	22.4	450	9066	27.8	22.9

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
79	9028	26.1	23.4	451	8429	25.6	21.8
80	9692	27.8	24.8	452	7269	21.7	19.8
81	9393	29.4	25.7	453	6734	20.6	19.0
82	9607	31.1	26.4	454	6678	19.4	18.4
83	9339	32.2	26.8	455	5881	17.8	17.4
84	9256	32.2	26.9	456	5657	17.8	17.4
85	8985	31.1	26.6	457	5426	16.7	16.7
86	9092	32.2	27.5	458	4846	17.2	17.0
87	9025	32.8	27.8	459	5127	17.8	17.3
88	8727	32.8	27.7	460	5165	14.4	15.3
89	8592	32.8	27.9	461	5234	13.9	15.0
90	7330	32.2	27.6	462	6064	14.4	15.3
91	5797	30.0	26.4	463	8083	17.8	17.6
92	6382	28.3	25.4	464	8025	21.7	19.9
93	5818	26.7	24.2	465	8295	24.4	21.5
94	5606	26.1	23.8	466	8450	26.1	22.4
95	5397	25.0	23.2	467	8860	27.2	22.9
96	4870	25.0	23.2	468	9181	27.8	23.2
97	4570	24.4	22.7	469	9130	28.3	23.5
98	4433	23.9	22.4	470	9198	29.4	24.1
99	4363	23.9	22.4	471	9436	30.6	24.8
100	4357	23.9	22.4	472	9419	28.9	24.2
101	4554	23.3	22.1	473	9819	28.3	24.0
102	5760	22.8	21.6	474	9385	26.7	22.4
103	7214	22.2	21.0	475	7959	25.0	21.9
104	6967	23.9	22.2	476	7252	22.8	21.0
105	7775	25.6	23.3	477	7031	22.2	20.8
106	8326	25.6	23.5	478	6960	22.8	21.0
107	8364	27.8	24.6	479	6474	22.2	20.8
108	8505	26.7	23.6	480	5196	22.2	20.8
109	8495	26.1	23.3	481	4653	20.6	19.7
110	8274	27.8	24.1	482	4566	20.0	19.4
111	8730	27.8	24.1	483	4861	19.4	19.1
112	8317	28.9	24.9	484	4441	18.9	18.7
113	8069	28.3	24.4	485	4235	19.1	19.0
114	7173	27.8	24.1	486	4448	19.1	19.0
115	5221	26.1	23.0	487	4854	20.0	19.4
116	5517	23.9	21.6	488	5526	20.0	19.5
117	5288	21.7	20.5	489	6317	21.0	20.0
118	4881	20.6	19.9	490	6795	22.2	20.7
119	4763	19.4	19.3	491	7177	23.3	21.2
120	3987	18.3	18.5	492	6956	23.5	21.3

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
121	3474	17.8	18.1	493	6712	25.6	22.5
122	3477	18.3	18.3	494	6879	26.7	23.0
123	3443	17.2	17.6	495	7139	27.8	23.7
124	3548	18.9	18.7	496	6197	27.8	23.8
125	3815	17.2	17.5	497	6669	28.3	24.2
126	4444	17.8	18.1	498	6753	27.2	23.7
127	6387	20.6	19.9	499	6582	25.6	22.8
128	6770	21.7	20.6	500	6848	24.4	22.1
129	6680	25.0	22.2	501	6290	23.9	21.9
130	6789	26.1	22.7	502	6161	23.3	21.6
131	7100	25.6	22.6	503	5864	22.8	21.4
132	7426	27.2	23.5	504	5533	22.8	21.4
133	7889	27.8	24.1	505	5440	22.8	21.4
134	8254	28.3	24.5	506	4923	22.2	21.0
135	8302	29.4	25.2	507	4587	21.7	20.8
136	8371	28.3	24.6	508	4628	21.7	20.8
137	8449	27.8	24.0	509	4632	21.1	20.4
138	7514	28.3	24.2	510	4642	21.7	20.8
139	6187	26.7	23.0	511	4949	22.8	21.4
140	5996	23.9	21.4	512	5692	25.0	22.6
141	5481	22.2	20.4	513	6280	27.8	24.2
142	5584	22.2	20.3	514	6872	30.0	25.3
143	5424	19.4	18.9	515	7617	32.2	26.6
144	4820	18.9	18.6	516	7618	33.3	27.4
145	4121	17.2	17.5	517	7379	33.9	27.8
146	3993	17.8	18.0	518	7548	33.3	27.5
147	4004	16.1	16.7	519	7933	35.0	28.4
148	3995	16.1	16.8	520	8055	31.1	26.2
149	3998	16.1	16.8	521	7810	30.0	25.4
150	3877	16.1	16.8	522	7570	28.3	24.5
151	4548	17.8	18.0	523	7092	27.2	23.8
152	5051	21.1	20.1	524	7297	25.0	22.6
153	5491	24.4	22.1	525	7475	23.9	21.9
154	6001	25.6	22.5	526	7018	23.9	21.8
155	6532	28.3	24.0	527	6467	22.8	21.2
156	6594	29.4	24.4	528	5811	21.1	19.9
157	6528	30.6	24.8	529	6653	21.7	20.2
158	6395	31.1	25.2	530	5688	21.1	19.7
159	6563	31.1	25.2	531	5810	18.9	18.4
160	5974	31.1	25.0	532	5604	19.4	17.9
161	6491	31.1	24.9	533	5957	18.3	17.2
162	6421	30.6	25.0	534	6843	17.8	17.1

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
163	6397	28.3	23.6	535	8017	18.3	17.3
164	6348	27.2	22.9	536	8901	19.4	18.1
165	6172	23.3	21.1	537	9988	22.8	19.8
166	6038	21.7	20.3	538	10033	24.4	20.7
167	5775	19.4	19.1	539	10167	26.1	21.7
168	5340	18.9	18.7	540	10444	27.2	22.4
169	5056	20.0	19.4	541	10530	26.7	22.2
170	5025	17.8	18.0	542	10825	26.7	22.1
171	5063	16.7	17.1	543	10895	27.2	22.2
172	4887	18.3	18.2	544	10973	26.7	22.2
173	4836	16.1	16.8	545	10563	25.6	21.8
174	4960	16.7	17.1	546	9686	26.1	22.0
175	5670	19.4	18.8	547	8866	22.2	19.9
176	6133	21.7	20.4	548	8452	22.8	20.2
177	6450	25.6	22.6	549	8527	18.3	17.9
178	6761	28.3	24.0	550	7567	17.8	17.6
179	7390	30.0	24.4	551	6622	17.8	17.6
180	7762	30.6	24.9	552	5671	17.2	17.2
181	7842	31.7	25.1	553	4635	16.1	16.5
182	7947	31.7	24.9	554	4177	17.1	17.1
183	8187	31.7	25.0	555	4414	17.6	17.5
184	7838	32.2	25.2	556	4505	17.0	17.4
185	8370	31.7	24.7	557	4702	17.1	17.6
186	7910	30.0	23.9	558	5182	17.1	17.7
187	8107	26.7	22.5	559	6221	17.2	17.7
188	8125	25.6	22.0	560	7434	19.4	18.7
189	8725	23.9	21.3	561	7503	21.1	19.4
190	8840	24.4	21.7	562	7813	22.8	20.5
191	8520	23.9	21.4	563	7622	24.4	21.4
192	6885	22.8	20.8	564	7301	25.6	22.0
193	6875	23.3	21.1	565	7308	27.2	22.8
194	6754	23.3	21.1	566	7212	27.8	22.9
195	6745	22.2	20.8	567	7234	27.8	22.8
196	7175	21.1	20.3	568	6868	28.3	23.3
197	7088	21.0	20.1	569	7201	27.8	23.0
198	6946	21.1	20.3	570	6273	26.7	22.5
199	7759	20.6	19.9	571	5694	24.4	20.9
200	9007	21.7	20.5	572	5263	23.3	20.3
201	9023	21.7	20.5	573	4849	22.2	19.6
202	9344	22.2	20.9	574	4589	21.1	19.1
203	9819	22.8	21.2	575	3995	21.1	19.0
204	10129	24.4	21.9	576	3849	18.9	17.8

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
205	10318	26.1	22.6	577	3282	18.3	17.6
206	10475	26.7	23.2	578	2916	17.8	17.4
207	10537	26.1	22.8	579	2795	15.6	16.2
208	10416	26.1	22.8	580	2622	14.4	15.3
209	10387	26.1	22.5	581	2504	14.4	15.3
210	10207	26.1	22.6	582	3006	13.3	14.6
211	9288	23.9	21.6	583	3826	16.7	16.8
212	9361	22.8	21.0	584	4008	19.4	18.3
213	9146	21.7	20.4	585	4686	22.2	19.7
214	8692	21.7	20.5	586	5661	23.9	20.8
215	8197	20.6	19.8	587	6789	25.0	21.4
216	8176	18.9	18.9	588	6809	26.7	22.3
217	6707	18.3	18.3	589	6894	26.7	22.0
218	6256	17.2	17.6	590	6994	27.8	22.8
219	5869	16.7	17.2	591	7078	28.3	23.1
220	5784	17.2	17.5	592	7023	27.8	22.8
221	5547	16.1	16.8	593	7161	28.3	23.2
222	5808	15.6	16.4	594	6334	26.7	22.1
223	6585	17.8	18.0	595	5762	24.4	20.6
224	7413	21.1	20.1	596	5397	23.3	20.2
225	6971	23.3	21.1	597	5328	22.2	19.7
226	8313	25.6	22.4	598	5007	21.7	19.4
227	8168	27.8	23.6	599	4552	20.6	18.9
228	8249	28.9	24.3	600	4235	20.0	18.7
229	8605	30.0	24.9	601	3467	20.0	18.8
230	8945	30.0	25.0	602	3209	18.9	18.2
231	8905	31.1	25.5	603	3120	17.8	17.6
232	8508	30.6	25.2	604	3046	17.2	17.3
233	8532	29.4	24.6	605	3140	16.1	16.6
234	8557	26.7	23.5	606	3688	15.0	15.9
235	8132	27.2	23.8	607	4046	17.2	17.3
236	8081	25.6	23.0	608	4986	19.4	18.5
237	7710	22.2	21.3	609	5260	20.6	19.3
238	7137	22.8	21.8	610	6492	22.2	20.3
239	6373	22.8	21.7	611	6798	23.3	20.9
240	5690	21.7	21.0	612	7120	23.9	21.2
241	6734	21.7	20.9	613	7150	25.6	22.1
242	6346	21.1	20.4	614	7345	26.7	22.7
243	6749	21.7	20.6	615	7192	26.7	22.5
244	6660	21.7	20.6	616	7379	27.2	22.7
245	6385	21.1	20.2	617	6990	27.2	22.8
246	6695	20.6	19.9	618	6699	26.7	22.4

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
247	6971	20.6	19.9	619	5981	24.4	21.3
248	6529	21.1	20.2	620	5675	22.8	20.5
249	5186	23.3	21.5	621	5388	22.2	20.3
250	5011	26.1	23.3	622	4668	21.1	19.8
251	9964	27.8	24.2	623	4603	21.1	19.8
252	10003	27.2	23.8	624	3991	21.7	20.0
253	10381	27.8	23.9	625	3416	20.0	19.1
254	10347	27.8	24.0	626	2947	20.0	19.1
255	10508	27.2	23.7	627	3392	19.4	18.7
256	10047	27.2	23.7	628	3153	18.3	18.2
257	9739	28.3	24.2	629	3200	18.3	18.1
258	9032	27.2	23.7	630	3860	18.9	18.4
259	8534	27.2	23.7	631	4915	19.0	18.8
260	8396	24.4	22.1	632	4960	18.3	18.5
261	8558	24.4	22.1	633	5697	19.2	19.2
262	8258	22.2	21.0	634	6282	22.4	21.0
263	8127	22.2	20.5	635	6838	25.6	22.9
264	7111	18.6	18.7	636	7122	27.2	23.8
265	7355	17.9	18.3	637	6991	28.3	24.5
266	7240	17.8	18.1	638	7154	29.4	25.1
267	7270	18.1	18.2	639	7179	30.0	25.4
268	6910	17.9	18.1	640	7098	30.0	25.7
269	6580	17.8	18.0	641	7170	29.4	25.4
270	6835	17.2	17.5	642	5917	29.4	25.6
271	7270	18.3	18.2	643	5406	28.9	25.4
272	10048	20.0	19.2	644	5008	27.8	24.8
273	8987	22.8	20.8	645	4697	27.2	24.5
274	9269	25.0	21.9	646	4631	26.7	24.1
275	9857	26.7	23.0	647	4564	26.7	24.1
276	10239	27.8	23.7	648	3543	26.7	24.1
277	10394	28.9	24.3	649	3081	26.7	24.0
278	10677	29.4	24.4	650	3022	26.1	23.5
279	10959	30.6	25.1	651	3092	25.0	22.8
280	9735	30.6	25.1	652	2590	24.4	22.4
281	10349	30.0	24.9	653	2611	22.8	21.4
282	9426	29.4	24.6	654	2984	22.8	21.4
283	8909	26.7	23.1	655	3017	22.8	21.5
284	8425	25.6	22.5	656	3392	25.0	22.9
285	7954	23.9	21.6	657	3930	27.2	24.4
286	7767	22.8	21.2	658	4524	27.2	24.1
287	7344	21.7	20.5	659	4992	29.4	25.0
288	6563	20.6	19.8	660	5130	29.4	24.0

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
289	5972	21.1	20.1	661	5381	30.2	24.7
290	5557	20.0	19.4	662	5503	31.7	24.8
291	5701	19.4	19.1	663	5751	31.1	24.9
292	5710	18.3	18.5	664	5919	30.6	24.4
293	5587	19.4	18.9	665	5774	29.4	23.8
294	6414	19.4	18.9	666	5486	27.8	22.7
295	6883	20.6	19.7	667	5402	23.3	20.5
296	7340	22.2	20.7	668	5087	19.4	18.4
297	8370	23.3	21.2	669	4677	18.9	17.9
298	9002	26.1	22.8	670	4749	16.7	16.6
299	9170	28.9	24.4	671	4324	17.8	17.1
300	9946	30.6	25.4	672	3666	13.9	14.8
301	9700	31.1	25.4	673	3420	14.4	15.0
302	9961	32.8	25.7	674	3189	12.2	13.6
303	10426	31.7	25.1	675	3131	11.7	13.3
304	9950	32.2	25.4	676	3018	13.3	14.2
305	9990	31.7	25.4	677	2612	10.6	12.5
306	8957	30.0	24.8	678	2704	11.1	12.9
307	7956	28.9	24.4	679	3629	12.8	14.1
308	7325	27.2	23.6	680	3543	17.8	17.1
309	5979	23.9	22.0	681	3790	22.2	19.6
210	6536	24.4	22.0	682	4999	24.4	20.8
311	6168	23.2	20.9	683	5058	27.8	22.5
312	5404	21.4	20.0	684	5874	28.9	23.1
313	4488	21.1	19.7	685	6096	30.6	23.9
314	4583	20.0	19.2	686	6800	31.1	24.2
315	4666	20.6	19.2	687	6849	31.1	24.3
316	4510	19.4	18.5	688	6835	31.1	24.0
317	4722	18.9	18.3	689	6441	30.6	23.9
318	5477	18.9	18.3	690	6030	29.4	23.3
319	4777	19.4	18.6	691	5920	28.3	23.0
320	5793	20.6	19.3	692	5990	23.3	20.3
321	6476	21.7	20.0	693	5704	21.7	19.5
322	6997	23.3	21.0	694	5400	19.4	18.4
323	6321	24.4	21.6	695	5200	18.3	17.7
324	7705	26.1	22.7	696	4713	18.3	17.6
325	7488	28.9	24.5	697	4881	17.8	17.2
326	6986	30.0	24.8	698	4640	16.7	16.6
327	6876	28.9	24.2	699	4484	16.1	16.1
328	6697	29.4	24.3	700	4495	12.2	13.8
329	5828	28.9	24.2	701	5624	13.9	14.9
330	6121	27.8	23.7	702	6148	13.3	14.5

Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)	Time (Hour)	Cooling Load (Tons)	Temp (℃)	Humidity (%)
331	6406	26.1	23.0	703	7504	15.0	15.6
332	6323	22.8	21.3	704	8079	17.8	17.5
333	5645	21.1	20.2	705	8421	22.8	20.4
334	5092	20.6	19.9	706	8829	27.2	22.7
335	4854	20.0	19.5	707	8667	28.3	23.5
336	4011	20.6	19.8	708	9989	30.0	24.2
337	3552	20.0	19.5	709	10232	31.7	24.9
338	3150	19.4	19.1	710	10595	32.2	25.2
339	3111	19.4	19.1	711	10866	32.2	25.3
340	3191	17.2	17.6	712	10915	32.2	25.3
341	3381	16.7	17.4	713	10616	31.1	25.0
342	2833	17.8	18.1	714	9165	30.0	24.1
343	3259	18.9	18.8	715	8495	27.8	22.9
344	3440	21.7	20.6	716	7583	26.7	22.2
345	3526	23.9	21.9	717	7217	25.6	21.6
346	4530	25.6	22.9	718	6588	23.9	21.2
347	5180	26.7	23.5	719	6240	23.9	21.2
348	4885	27.2	23.7	720	5769	22.8	20.6
349	4787	27.2	23.5	721	5504	22.2	20.4
350	4740	27.8	23.7	722	5447	21.7	20.0
351	4849	27.8	23.5	723	5349	21.1	19.7
352	5100	28.3	23.6	724	5351	21.1	19.7
353	5085	28.3	23.6	725	5468	21.1	19.7
354	4900	26.7	22.9	726	6079	20.6	19.4
355	4880	24.4	21.7	727	8900	21.1	19.9
356	4840	21.7	20.2	728	9322	23.3	21.2
357	4510	22.2	20.6	729	9724	26.7	23.4
358	4510	22.2	20.5	730	10211	28.9	24.7
359	4180	20.6	19.6	731	10348	31.1	25.9
360	3697	20.0	19.3	732	10465	32.2	26.5
361	3571	18.9	18.7	733	10605	33.3	27.1
362	3328	17.8	17.8	734	10959	32.8	26.9
363	3422	18.3	18.1	735	11054	32.8	27.0
364	3506	15.6	16.3	736	10753	33.3	27.1
365	3936	15.6	16.3	737	10912	32.2	26.5
366	4399	15.0	16.0	738	10417	31.1	26.0
367	4928	17.2	17.4	739	9251	29.4	25.1
368	5794	20.0	19.2	740	8644	28.9	24.9
369	6595	22.8	20.6	741	7179	27.8	24.3
370	7097	24.4	21.5	742	6602	26.7	23.9
371	7102	26.1	22.3	743	5700	26.1	23.5
372	7518	26.7	22.5	744	4853	24.4	22.6