DEVELOPMENT OF A METHODOLOGY FOR VOLTAGE SENSITIVE GENERATION SCHEDULING

A thesis submitted to the Department of Electrical and Electronic Engineering, Bangladesh University of Engineering and Technology, in partial fulfillment of the requirements for the degree of

Doctor of Philosophy

by

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Declaration

This is to certify that this research work has been performed by me and it has not been submitted elsewhere for the award of any degree or diploma excepting for publication.

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Abstract

This thesis addresses scheduling conventional generation units keeping in view the low voltage problem. In a power system low voltage occurs when requisite reactive power support is not available. The problem will aggravate further in emerging power systems which will have electricity market oriented operation and large scale penetration of intermittent renewable based generation resources. Market operation makes the reactive power supports often scarce. Renewable sources involve DC-AC or AC-DC-AC conversion requiring adequate reactive power support. Besides this, renewable sources themselves may be unavailable totally in non-congenial weather.

Voltage management through transformer tap changing, line switching, capacitor switching and lastly load shedding has long been practiced in power industry. But these may end up in voltage collapse or voltage instability due to hitting the ceiling (limit) of these devices/actions. So bus voltage in problematic areas may be improved if the generators in their neighborhoods can be scheduled. This is because reactive power is less mobile (i.e. cannot flow over a long distance unlike real power), and generators are active devices whose excitation can be controlled to supply or absorb reactive power. It appears that all the existing scheduling methods are sensitive to fuel-cost characteristics and select cheaper units considering only real power demand but do not select the units considering the impact on bus voltages. After scheduling the units the load is allocated among them by an optimal power flow (OPF) which takes care of operating and network constraints. But low voltage problem cannot be solved this way if the units near the problematic areas (even though their fuel cost may be relatively higher) are not selected at the scheduling stage before the OPF.

In this research a new methodology for scheduling has been developed for considering bus voltages. This ensures that the generation units which are able to improve the system voltage profile will be selected. For this a new optimization function is formed augmenting the classical Lagrange function for the total time period (i.e. 24 hours) by a bus voltage sensitive function. Notably the classical Lagrange function for selection of units comprises only the fuel cost and load balancing constraint. In the voltage sensitive function, each bus voltage magnitude excepting that for the slack bus in each hour has been modeled in terms of (i) the elements of a network matrix, (ii) a negative injected current contributed by the shunt admittance including line charging susceptance and load (real and reactive) at each bus, and

(iii) both real and reactive power outputs of the generation units to be evaluated for scheduling. The network matrix is similar to bus impedance matrix but it is formed excluding the slack bus and all shunt admittances and line charging susceptances. The real power (I^2R) loss in transmission lines has also been embedded in the new Lagrange function as a fraction of the real power outputs of the units being evaluated for selection.

The proposed scheduling method has been extensively tested on the IEEE 30 bus standard system under diverse forecasted loading scenarios for a period of 24 hours and various sets of cost parameters for the generation units. The results are compared in each case by running OPF separately using the units scheduled by respectively (i) the classical Lagrange method and (ii) the proposed method. In general compared to the classical method the proposed scheduling method has been able to so select the generation units that led to better OPF results i.e. better overall performance in terms of convergence, transmission loss and number of buses with voltage magnitudes significantly above the minimum value, at a marginal cost addition.

The potentials of the proposed method (i.e. the voltage sensitive generation scheduling) in a real life system have also been demonstrated by applying and comparing it against the classical Lagrange method for 93-generator and 166-bus Bangladesh Power System (BPS).

Suggestions have also been made on how the proposed method can be used for accommodating spinning reserve at the scheduling stage. The developed method is expected to be useful also for the ISOs (Independent System Operators) in deciding transmission network access to the generation units which have submitted on-line bids for a time period comprising a number of hours together.

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List of Principal Symbols and Abbreviations

AGC: Automatic Generation Control

ACE: Area Control Error

BPS: Bangladesh Power System

DP: Dynamic Programming

DERs: Distributed Energy resources

ED: Economic Dispatch

GA: Genetic Algorithm

ISO: Independent System Operator

IEEE: Institute of Electrical and Electronics Engineers

LR: Lagrange Relaxation

LP: Linear programming

MILP: Mixed Integer Linear Programming

MCP: Market Clearing Price

NLDC: National Load Dispatch Centre

NLP: Non Linear Programming

OPF: Optimal Power Flow

PHEV: Plug-in Hybrid Electric Vehicles

PSO: Particle Swarm Optimization

SCADA: Supervisory Control and Data Acquisition

$F_i\left(P_{gi}^t\right)$ = The fuel cost incurred by unit i in interval t

a_i = Cost characteristic coefficient ($\$/MW^2/h$)

b_i = Cost characteristic coefficient (\$/MWh)

c_i = Cost characteristic coefficient (\$/h)

d= Duality gap

I_i^t = Current injection in pu at the bus of generation unit No. i in interval t

I_k^t = Current injection in pu at the bus where only load k is connected in interval t

J = Primal value over 24 hours (\$)

L = The Lagrange function

N= Total number of units available for commitment in the period T
N_b= Total number of buses =(N +N_{Lb})

N_{Lb} = Number of only load connected buses

p = Ratio of transmission loss in an interval to the sum of the outputs of the units selected in the same interval

P_i^t = The real power (MW) injection at the bus of generation unit No. i

$P_{gi}{}^t$ = Output (MW) of generation unit i in the interval t

P_{gi}^{Max} = Maximum Capacity of the generation unit No. i

P_{gi}^{Min} = Minimum Capacity of the generation unit No. i

$P_{dk}{}^t$ = Real load (MW) in interval t at the bus where only load k is connected

$P_{load}{}^t$ = Total system load (MW) in interval t

q = Dual value over 24 hours ($)

Q_i^t= The reactive power (MVAR) injection at the bus of generation unit No. i

Q_{gi}^t= Reactive power output (MVAR) of generation unit i in the interval t

$Q_{dk}{}^t$ = Reactive load (MVAR) in interval t at the bus where only load k is connected

s_i = The ratio of the reactive power injection to the real power injection at the bus of generation unit No. i

s_k = The ratio of the reactive load to the real load in interval t at the bus where only load k is connected

$SUC_i{}^t$ = Start up cost of unit i in interval t

t= 1,2,3…… N_t; is any time interval (hour)

N_t = Total number of intervals (hours) for scheduling and usually equal to 24

$U_i{}^t$ = Status of the unit i in interval t which will be either 0 (if not selected i.e. OFF status) or 1 (if selected i.e. ON status)

V_{slack} = Pre-specified slack bus voltage phasor i.e. magnitude and phase angle

$|V_b^t|$ = Voltage magnitude at bus any bus b (not equal to slack bus) in interval t with ground bus as the reference

$y_{sh,i}$ = Total shunt admittance (pu) at bus i including charging susceptance, external reactor/capacitor

$Z_{bi} = R_{bi}+jX_{bi}$ is the element (in pu) between bus b and the bus of generator i in the bus impedance matrix [Z]

$Z_{bk} = R_{bk}+jX_{bk}$ is the element (in pu) between bus b and the bus of load k in the bus impedance matrix [Z]

λ^t = Lagrange multiplier in interval t in unit of **$/MW/h or $/h/MW**

μ^t = Another Lagrange multiplier in interval t in unit of **$/h/pu voltage difference**

$\in$ = maximum allowed duality gap

Chapter 1 Introduction

This chapter defines the problem addressed by this thesis and presents in a coherent and unified way the state-of-the-art of the research done on the subject. Based on this the chapter highlights the objectives, scope and contributions of the present research.

1.1 General Considerations

The modern civilization needs for its sustainable evolution a secure and economic supply of quality electrical energy in bulk quanta. This is delivered from a large interconnected high or extra high voltage power system also termed the grid. Control of the grid, the largest man made engineering complex, is getting complicated day by day. The reasons are manifolds viz. lack of versatile generation mix in a given utility (e.g. hydro, nuclear, coal, gas, oil), penetration of utility scale renewable energy based intermittent generation resources, market driven operation i.e. competition among generation entities, and forecast errors on the consumers' demand. The outcome of all these complications is reflected in the form of deviations in voltage and frequency from their nominal values. The voltage and frequency deviations can greatly be contained by appropriate scheduling [1] of the conventional thermal generation units from a set of available units and their dispatching. If the scheduling is done such that requisite reactive power supports where needed are available from the scheduled generation units then the voltage deviation would reduce. The frequency deviation results due to mismatch between generation and actual load and so it would reduce if requisite spinning reserve is available from the scheduled units for manipulation through AGC (Automatic Generation Control).

1.2 The Problem Statement

In power system operation load is forecasted for a period of 24 hours. Then the generation units from a set of available units are scheduled (i.e. decided to be turned 'On' or 'Off') considering mainly the fuel cost and generation-load balance with the objective of total fuel cost minimization over 24 hours. After scheduling is done, the hourly load is dispatched (allocated) among the units scheduled in the corresponding hour independently of any other hour.

The basic difference between scheduling and dispatching is that the former selects (commits) the units and minimizes the production cost over the total time period while the latter (dispatching) does not decide selection. Rather given the selection, a dispatching method allocates the load in an individual hour among the units already selected for that hour. So scheduling is the predecessor of dispatching and it is more crucial than dispatching.

It is true that the motive behind generation scheduling and dispatching is fuel cost minimization. If the scheduling is done without considering a constraint, the fuel or production cost would be less than that when the constraint is considered. But in actual implementation of the schedule, the saving in cost is very likely to be offset or reduced by violation of the constraints that have not been considered at the scheduling stage. However, consideration of too many constraints at the scheduling stage which has to evaluate a large number of available units over many consecutive intervals is difficult. This is the reason that all the constraints are not considered by the existing methods at the scheduling stage rather considers some of the constraints at the dispatch stage. Checking constraints at the dispatching stage is easier as it evaluates only the units that are already selected specific to a single interval.

One of the major operational goals in a power system is maintaining desired voltage at all the buses in a power system. The performance of the electrical appliances specially the motor loads, which have the major share in any utility will degrade due to under voltage. This is true also for power station auxiliaries that include motors so that power station output will reduce. Besides these, under voltage causes excessive current flow from source to load entailing a higher transmission loss. If under voltage cannot be contained by other means it would necessitate load shed else voltage instability leading to system collapse will result.

Voltage management through transformer tap changing, line and capacitor switching has long been practiced in power industry. But these may prove inadequate in case required reactive powers are not available in the problematic areas. This requires scheduling (selecting) appropriate generators in the neighbourhood of problematic areas so that those can supply reactive power besides real power. This would be possible if the generation scheduling method considers not only the fuel cost of the units but also their individual abilities to improve system voltage.

Thus the present research problem can be stated as developing an optimization method for selecting appropriate generation units in each interval of a given time period so that the total fuel cost is minimized subject to satisfying the load and maintaining the system voltage at an acceptable level.

1.3 Review of Literature

A chronological and extensive review of the literature [2-78] reveals that a good deal of research has been done in the area of both generation scheduling and dispatching. Since decisions given by a scheduling method are passed on to a dispatching method for load allocation, the existing dispatching methods need to be also reviewed. This would help identify the most suitable dispatching method for the comparison of the impacts on the system due to a new scheduling method against those due to a well-established (classical) scheduling method.

The works reported so far on dispatching can mainly be categorized as (a) OPF (Optimal Power Flow) [5, 18, 23, 36, 37, 40, 43-45, 50, 55, 56, 59,62,70, 72-76] using various mathematics based optimization techniques and (b) Evolutionary programming based methods [3, 4, 6-8,12-14,19-21, 25, 29-32, 34, 35,38,41, 42, 46-49, 52, 53, 57, 58,60, 64, 66,68, 77].

The OPF and its different variants are rigorous mathematics based and provide high accuracy. Some of those apply artificial neural network [18] and fuzzy logic [44] to reduce computational time requirement. OPFs determine the outputs to be given by the generation units already scheduled (committed) in each interval. For this the OPFs minimize the sum of the cost functions for the scheduled units subject to load flow equations using a non-linear or linear programming solution technique. The other operating constraints (e.g. bus voltage limits, line losses, line flow limits, unit’s real and reactive power limits) are checked through a rule base. In case any constraint is violated the load allocation is recomputed through a brief procedure or the violated constraint is put at its limits.

The evolutionary methods e.g. genetic algorithm (GA), simulated annealing, particle swarm optimization (PSO) and their variants basically begin with an assumed initial solution vector for dispatching problem in each time interval. The solution is updated iteratively in a heuristic way adapted from various biological or natural phenomena e.g. transfer of genetic information from offspring to offspring through chromosomes (GA), information exchange among a flock of birds or a column of ants moving to the destination in search of food (PSO) etc. The quality of the updated solution is checked using a fitness function that reflects the generation cost functions in a heuristic way. But the fitness function cannot consider many constraints and avoids use of network modeling matrices. The updating continues till the solution on every decision variable satisfies the fitness function. The methods are very fast due to not using any network matrices. However, the proper choice of fitness function and control parameters specific to the updating mechanism is difficult. This is one of the reasons that these methods appear to have not yet been attractive as dispatching methods to the practical utility control centres.

It should be noted that the reported dispatching methods can be converted to a stochastic [25, 40] version assuming some statistical distribution and probability level for the hourly forecasted load, available generation capacities, and fuel cost parameters. However, stochastic modeling is very much suited when there are uncertainties about the actual conditions e.g. at the planning stage that leads the operational stage by several years or decades. On the other hand in daily operation the information become clearer or more deterministic specially 24 hours ahead of generation dispatching so that a stochastic modeling of the variables and parameters may be avoided in required in scheduling.

Though the OPF methods are computationally intensive and may not converge depending upon the number and location of the committed units and constraints, these are more accurate than evolutionary methods. So OPF method is widely used for dispatching.

The methods reported in literature for scheduling are (a) Merit order method [1, 2, 10,11], (b) Dynamic programming [1, 10, 11], (c) Lagrange Relaxation method [1, 10] using (i) non-linear programming (NLP) solution technique [22, 28, 54, 67], (ii)mixed integer linear programming (MILP) [9, 16, 17, 24, 63, 78] which is a variant of linear programming, (iii) MILP with stochastic modeling [33, 69], and (d) Evolutionary algorithms [15, 26, 27, 39, 51, 61, 65, 71]. Since the present research addresses the scheduling problem the reported works for scheduling have been reviewed elaborately in Chapter 3. However, the gap observed in the reviewed scheduling methods is focused below.

Among all the methods reviewed the Lagrange Relaxation (LR) method is the most systematic generation scheduling method and amenable to adaptation. The major drawback of this and other methods reported for scheduling is that none of these consider bus voltage in the objective function used for selecting an optimum schedule of the generation units. The methods assume that either the system has a good voltage profile or the voltage problem will be checked at the dispatching stage. But as mentioned in Section 1.2, other methods of voltage control are not adequate to maintain a good voltage profile and so appropriate generation scheduling is required. Moreover, given the scheduled generators a dispatching method cannot select new units to improve voltage. So there is much scope to improve the existing scheduling methods from voltage point of view.

1.4 Objectives

The present research focuses on the following main objectives.

i. To enhance the understanding of the role of generation scheduling as the control paradigm shifts from a traditional vertically integrated system to an electricity market driven power system and eventually to a smart grid.

ii. To make a critical review of the methods of generation scheduling reported in the literature so that the basis for a research can be formed.

iii. To develop a novel methodology for generation scheduling changing the widely used non linear programming based classical Lagrange Relaxation method and incorporating a network model so that bus voltage constraints and transmission loss can be considered right at the scheduling stage.

iv. To validate the developed scheduling method through extensive simulation tests and comparison of the performance with that of the classical Lagrange Relaxation method on identical basis i.e. same load curve (24 hours' forecasted demand profile), same set of available generation units and cost coefficients in a standard test system.

v. To evaluate further the potentials of the developed scheduling method by applying it and comparing against the classical Lagrange Relaxation method for a real-life power system.

vi. To identify the ways the developed methodology can be further improved.

1.5 Scope

The present research is focused specifically on the following.

i. A method for selecting the conventional generation units against a forecasted load variation over 24 hours is developed. In this method the fuel cost, impact on bus voltages and transmission loss are considered simultaneously.

ii. Various types of conventional generation units having widely varying fuel costs are considered.

iii. The developed method is validated by applying it in the IEEE 30 bus system and comparing it against the classical Lagrange Relaxation method of scheduling. IEEE 30 bus system has long been accepted in the literature as the replica of a practical generation and transmission system.

iv. Further verification of the developed method against the classical Lagrange Relaxation method is done using Bangladesh Power System (BPS) which is a real-life system in a resource constrained developing country. BPS has 166 buses and 93 generators with a fuel mix of hydro, gas, oil and coal.

v. The way spinning reserve can also be considered in the developed method for scheduling the generation units, is suggested.

1.6 Contributions

The major contributions made by the present research are mentioned below.

i. A novel generation scheduling method has been evolved by modifying the classical Lagrange Relaxation method. For this the voltage magnitudes at all the buses (excepting the slack bus) and the transmission network loss have been embedded as function of the generation unit outputs in the optimization function. The details of the mathematics for the developed method have been presented. It should be noted that bus voltages and transmission loss are not considered by the existing methods at the time of scheduling generators. Rather these are left for the dispatching methods that allocate the loads among the units selected by the scheduling method.

ii. Appropriate indices have been developed in showcasing and comparing the results of extensive simulation tests of the developed method of generation scheduling against those obtained from the classical Lagrange method for generation scheduling. Besides this, comparison has also been shown applying the well known optimal power flow (OPF) for dispatching the generation units scheduled by both the methods in typical off-peak and peak hours of a standard test system and a real life power system.

Besides the above two, other important contributions that would benefit the research community are as follows.

iii. A review of the state-of-the-art methods in generation scheduling has been made. This helps in perceiving the limitations and drawbacks of the existing methods against the backdrop of the requirements posed by the current system operation trend.

iv. A coherent description on the role of generation scheduling in the context of traditional vertically integrated system, emerging deregulated (electricity market) system and smart grid, has been provided.

v. A unified presentation on the integration of the generation scheduling with AGC in the context of traditional, deregulated and smart power systems has been given.

vi. Applicability of the developed scheduling method for use by an ISO in electricity market has been suggested.

1.7 Organization of the Thesis

The material studied in the present research has been organized as follows.

In Chapter 2 the way generation scheduling interacts with other functions of the control centres i.e. operational load forecasting, economic dispatching or OPF, AGC in the context of a traditional, deregulated or smart grid system has been discussed.

Chapter 3 presents a critical review of the existing methods including classical Lagrange Relaxation (LR) method for generation scheduling. A brief overview of the mathematics for LR and OPF are also presented for a ready reference only.

Chapter 4 details the development process of the proposed scheduling method that modifies the classical Lagrange function taking into account the network model.

Chapter 5 presents and discusses typical results obtained from the extensive tests of the proposed scheduling method on IEEE 30 bus standard test system and a real life system i.e. Bangladesh Power system with 166 buses and 93 units, and compares the performance against that of the classical Lagrange Relaxation method for scheduling under the same scenarios of loading and cost coefficients. Also is presented a comparison of the results when OPF is run separately on each test system considering the generation units scheduled by (i) the developed method and (ii) the classical Lagrange method.

Chapter 6 summarizes the main findings of the present research and suggests some points for further investigation.

The Appendixes include supporting materials to Chapter 5.

Chapter 2 Role of Generation Scheduling

This chapter presents in a unified manner the state-of-the-art on integrating generation scheduling in emerging power system operation and control.

2.1 Introduction

The basic steps in the real time control of a typical power system are (i) forecasting the load usually 24 hours ahead, (ii) scheduling i.e. selecting the generation units from the available units for each of the 24 hours in one go, (iii) dispatching the selected units i.e. allocation of the hourly load in the most economic way among those selected for the corresponding hour, and (iv) implementing the dispatching decisions i.e. AGC (Automatic Generation Control).

In a vertically integrated system (where generation, transmission and distribution sectors are owned/controlled by the same entity) the forecasting, scheduling and dispatching are done by the load dispatch centre to optimize the production cost over 24 hours. In an electricity market (where generation companies have to offer competitive price in getting access to the transmission network) forecasting and scheduling are done by the transmission operator or Independent System Operator (ISO) calling for bids as well as the generation companies submitting bids. The ISO simulates a pre-bid scheduling among the prospective bidders' generation units to decide an expected market clearing price (MCP) [84] for each hour of a time period. MCP is the unit electricity price (e.g. $/kWh) at which electricity will be sold or bought so that customers' benefit termed social welfare [84] is optimized. Actual MCP is determined after the biddings take place and if it is widely different from ISO's expected value then fresh bidding is called for or the expected one is enforced. A generation company does pre-bid scheduling among its available generation units so that for each hour it can offer a quantum and unit energy price likely to make it bid winner with the maximum possible profit margin.

However, for electricity market oriented power system the AGC differs from that for the traditional one to some extent. In the traditional system AGC implements the decisions of scheduling and dispatching on scheduled units and any incremental change in load is also allocated among these units. In the electricity market driven system only the generation units winning an on-line bid in an hour take part in AGC to generate what they offered. Any incremental change in load is assigned by the ISO to one or more of those units agreeing to provide ancillary services such as real time load balancing, reserve margin etc. However, the ancillary service providers may also be new units which did not take part in bidding.

For the smooth operation of a power system the generation units are selected from a generation mix where possible i.e. generation units having diversified technical characteristics and fuel costs ranging from zero (hydro) or moderate (nuclear, coal) to the high values (gas, oil) are used for the scheduling. However, so far the utilities are performing generation scheduling and dispatching mainly for achieving economy. But the emerging problems and various factors that make a power system vulnerable and blackout prone warrant a new dimension in generation scheduling.

The threats to system security are (i) lack of proper generation mix in a generation company/utility, (ii) obligations imposed by energy regulatory bodies to accommodate distributed or utility scale intermittent renewable based generation resources [85] which may be totally unavailable in the worst case, (iii) conservative attitude of the electricity market players i.e. generation companies and distribution/load serving entities towards sharing comprehensive information with ISO, (iv) lack of infrastructure needed for implementing a smart grid [79] e.g. affordable broadband facilities for two way communication between the utility/ISO server and the end users or their remotely controllable appliances and storage devices [86, 87] such as rechargeable high power density batteries, plug-in hybrid electric vehicles (PHEV), and (v) unanticipated events. All these problems very often lead to a steady state frequency deviation and a system wide low voltage problem. These can greatly be reduced taking into account right at the generation scheduling stage the spinning reserve and voltage constraints besides the cost characteristics of the conventional units. However, among the conventional units the thermal generation units incur fuel costs and have the major share in generation mix.

2.2 Operational Load Forecasting

Short term or operational load forecasting is the prediction of future electricity demand by using some statistical techniques that adjust past demands to the present weather conditions and other anticipated events. Depending upon system dynamics e.g. change in demanded MW/minute, operational or short term forecasting takes place usually once a day or every few hours to develop an operating schedule of the generation units. In a smart grid environment the forecast is expected to be more accurate and free from uncertainties against the backdrop that continuous feedback from grass root level consumers will be available provided a two way communication system exists between ISO/ utility's control centre and the consumers. Consequently in a smart grid the real time load balancing or frequency deviation control will not be a crucial problem. But for voltage improvement and loss curtailment appropriate scheduling of generation units i.e. location of the units being scheduled is important.

2.3 Unit Scheduling

Unit scheduling also termed unit commitment is done after the load forecasting is made. It is a procedure to decide which of the available generators should start up or shut down in each hour of a time period of usually 24 hours such that the forecasted demand is met with an optimum saving in the total fuel cost of 24 hours. However, security related constraints such as bus voltages and spinning reserve are usually not considered in the presently available scheduling algorithms due to difficulties in modeling. Rather these are considered at the dispatching stage after selection. So the selected units may not be able to keep the system secure. It should be mentioned that only tap changing transformers and shunt capacitors may not be enough to maintain system voltage respectively because of limitations in the number and step size of tapping, and capacitor's reactive power output (V^2/X_c) that depends upon the local bus voltage itself. So bus voltage in problematic areas may be improved provided the generators in their nearest neighborhoods can be scheduled. This is because reactive power is less mobile [83, 84] i.e. cannot flow over a long distance unlike real power, and generators are active devices whose excitation can be controlled to supply or absorb reactive power.

2.4 Economic Dispatch

Economic dispatch (ED) function determines which of the committed generating units would generate how much power so that the cost of supplying the energy to meet the demand is minimized for individual intervals (hours). It is during economic dispatch when the transmission losses, voltage constraints, line flow limits etc. are considered specially through a more elaborate dispatch method known as Optimal Power Flow (OPF) for each hour separately after the units are already selected. However, had there been a consideration of these constraints during the scheduling stage the unit selection scenario would have changed.

2.5 Automatic Generation Control

AGC is a closed loop control system for implementing the decisions of scheduling and dispatching (for vertically integrated system) or on-line bidding process (for electricity market) on the generating units selected to achieve the following objectives.

i) to maintain system frequency;

ii)to adjust generation on all the scheduled or selected units from the respective base-point economic allocation in response to small-scale changes in demand;

iii) to control tie line power flow to meet interchange schedule in case the power system is interconnected with the another or the system comprises two or more interconnected areas;

iv) to make each area adjust its own generation for a change in its own load.

The AGC action is suspended during the emergency state of a power system to give priority to system restoration over economy while reinstated on return of the normalcy.

Fig. 2.1 shows [1] the AGC loop based on SCADA. Whenever load changes in an area this is reflected in the frequency and tie line flow so that an error signal termed ACE (Area Control Error) is formed. P_{base} shown in Fig. 2.1 is decided by economic dispatch (ED) of the units scheduled for a given interval. A non-zero ACE implies a load change by ΔP_{total} and if it occurs before the interval for another ED then the power generation desired (P_{des}) from each unit or some of the scheduled units which have spinning reserves (i.e. capacity exceeds allocation) in the current interval is changed by a corresponding fraction termed participation factor. The participation factor is derived from the cost characteristics of the generation units committed in the concerned interval. The new desired generation signal is transmitted from the server to the governor's supplementary control system of a unit at a power station and the feedback on what is actually being generated is sent back to the server through SCADA as shown [1] in Fig. 2.2 with respect to one of the concerned units.

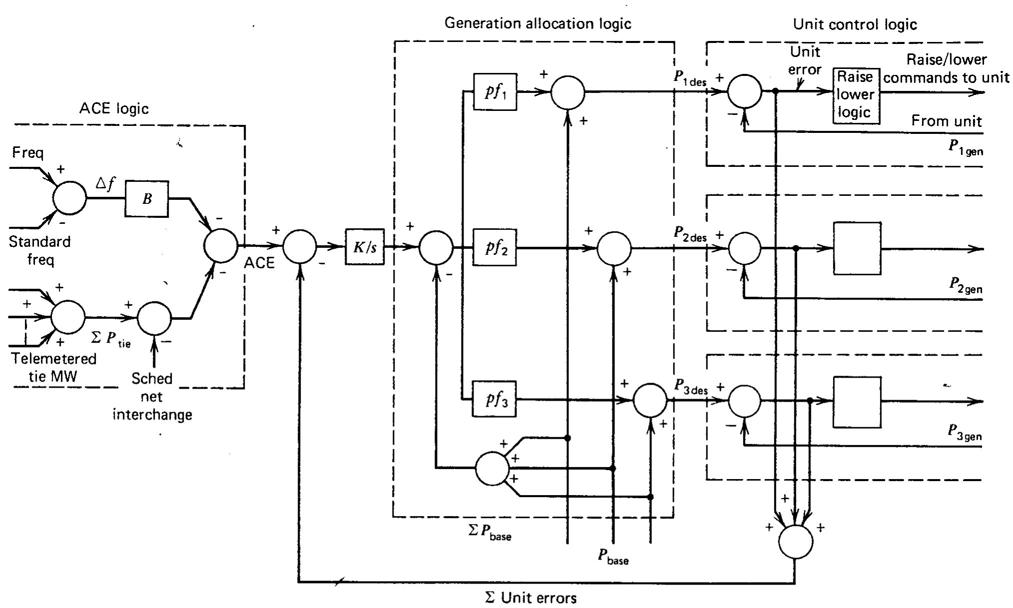

Figure 2.1 Underlying logic of an AGC scheme

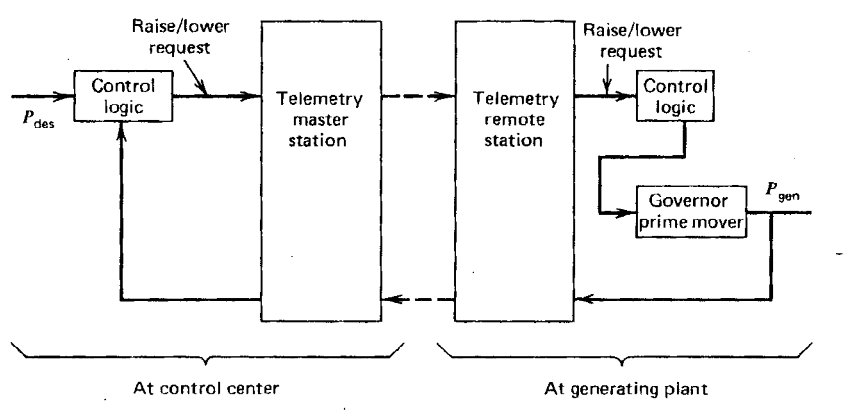

Figure 2.2 Transmitting AGC command and feedback through SCADA

However, in electricity market the base point allocations are the quanta offered by the successful bidding units and the responsibility of supplying the incremental load is assigned to the units which offered them for the ancillary services.

2.6 Conclusion

Generation scheduling is one of the real time functions performed in the modern energy control centres at least every 24 hours or more frequently in a day depending upon the load dynamics of the concerned power system. The forecasted load is most economically distributed among the scheduled units. If appropriately modeled, a scheduling method can ensure system security besides economy. In electricity market driven power systems the generation scheduling is practiced at the pre-bid stage by the ISO as well as generation companies mainly to assess the tentative cost. However, the voltage and other security constraints can be considered by the ISO in the post-bid stage scheduling (selection) or allocation of the generation units that have participated in bidding for an hour.

Chapter 3 Review of Existing Scheduling Methods

This chapter presents the critical review of the methods reported in the literature for generation scheduling. Also a brief overview of the mathematical model of the Lagrange relaxation (LR) method is presented. This is needed for a ready reference because the LR method is considered in the literature as the benchmark for other methods.

3.1 Introduction

In generation scheduling [1] the units are selected to be turned ON/OFF through a constrained minimization of the total cost function for the whole of a given time span such as 24 hours. Once this is finalized the load for every hour is allocated through an economic dispatch or optimal power flow independently of other hours only among the units scheduled for that hour.

Consideration of various operating constraints (that impact power system operation) in generation scheduling is very difficult. The constraints can be categorized broadly as coupling constraints and separable constraints. The coupling constraints are those which depend upon the outputs of all the units such as load balancing equation (i.e. generation equals load), bus voltages and spinning reserve constraint. Among these the most difficult is consideration of bus voltage constraints. This is because bus voltages are simultaneous functions of network model and generation outputs. Separable constraints relate to the respective individual unit only such as unit capacities, minimum up and down time, start up cost, ramp rate etc. and are easier to be handled.

As mentioned in Sec.1.3, methods reported in literature for scheduling are (a) Merit order method [1, 2, 10,11], (b) Dynamic programming [1, 10, 11], (c) Lagrange Relaxation method [1, 10] using (i) non-linear programming (NLP) solution technique [22, 28, 54, 67], (ii) mixed integer linear programming (MILP) [9, 16, 17, 24, 63, ,78] which is a variant of linear programming (LP), (iii) MILP with stochastic modeling [33, 69], and (d) Evolutionary algorithms [15, 26, 27, 39, 51, 61, 65, 71].

Needless to say, in all these methods, hydropower based generation units (if present in a system) receive the first priority and are dispatched subject to the available water head in an interval. Then to cater to the remaining load the actual steps of the methods are applied on the thermal units.

3.2 Merit Order Method

Merit order methods [1, 2, 10, 11] are based on full load average production cost i.e. the heat rate (Btu/kWh) calculated only at the full load multiplied by fuel cost ($/Btu) for the thermal units.

The merit order methods are simple and fast. These methods solve the problem unifying scheduling and dispatching i.e. for a given demand in an interval the units are selected in order of ascending full load average production cost and loaded up to their permitted capacity. However, these methods do not optimize any objective function taking into account any constraints so that the resulting scheduling is not the best one.

3.3 Dynamic Programming Method

The dynamic programming (DP) method [1, 10, 11] selects the most economic combination of units for each interval by enumerating all the possible combinations of the available units for an interval considering the cumulative production cost in various feasible combinations up to the preceding interval (forward DP) or up to the succeeding interval (backward DP). The DP techniques are more time intensive and not manageable with the increase in the number of generation units. However, voltage or any other constraint, excepting load constraint, minimum and maximum capacity constraint, is not considered in DP.

3.4 Lagrange Relaxation Method

Lagrange relaxation (LR) method [1, 10] selects the units for each interval on the basis of minimizing the fuel cost for the total time period. In doing so it relaxes the load balancing constraint (that generation should equal demand) i.e. augments the constraint with the cost function through a multiplier. The major difference between LR and DP methods is that the DP enumerates in each interval a number of feasible combinations from among the available units. On the other hand the Lagrange technique examines in each interval all the available units individually just in ON or OFF states if not restricted by minimum up or down time or must run or other unit specific constraint such as minimum and maximum capacity, ramp rate etc. However, like DP method, the LR method also does not consider voltage constraints and transmission loss during optimization.

3.4.1 NLP variants of Lagrange Relaxation Method

In the NLP variants [22, 28, 54, 67] of LR method a nonlinear objective function (quadratic cost function) is minimized subject to constraints such as load demand and capacity of generation units.

In [22] the scheduling is done for a one week period. So the solution was first obtained by classical LR and then further improvement was attempted using a heuristic technique i.e. changing the ON/OFF status of one or two units. However, usual operational cycle is 24 hours. Furthermore, voltage constraints are not considered in this work.

In [28] both LR and DP have been combined to solve the scheduling problem with improved convergence. However, voltage constraints have not been considered in the optimization function.

In [54] a method was proposed for scheduling of the conventional thermal units every five minutes in order to cope with the problems arising from increased penetration of photovoltaic generation sources. But this is not practical because of the ramping limitations and stresses that the thermal units would face. Needless to say voltage constraint is not included in the optimization function.

In [67] a method has been proposed to determine the status of the units in terms of a continuous variable ranging from 0.0 to 1.0 instead of 0 or 1 so that it serves the purpose of scheduling (selection) as well as dispatching (allocation). But as with other LR methods voltage constraint is not considered in this method.

3.4.2 MILP variants of Lagrange Relaxation Method

The LP based LR methods use linearized objective function as well as linearized constraints with integer (e.g. unit status) and continuous type control (e.g. generation outputs) variables, and are solved using MILP (Mixed Integer Linear Programming) [9, 16, 17, 24, 63, 78]. The LP and its variants are reported to have shown better convergence characteristics.

In [9] a method was proposed which considers a linearized objective function comprising thermal units' fuel cost and hydro units' start up costs. The work does not show how bus voltage constraints were considered in the optimization process. Moreover, a simple but uncommon 8-bus system assumed with zero line resistance was used to validate the method. The work claims line loss is considered. But then resistance should not be assumed to be zero.

In [16] a review of the application of Interior Point (IP) version of linear programming in generation scheduling is shown. However, voltage constraints were not considered. Rather bus voltages were assumed to be always 1.0 per unit.

In [17] a method has been reported to schedule separately the generation units and the transmission lines for maintenance purposes using NLP based LR technique for a longer time horizon (one week to several months). Then the results are coordinated with a MILP based security constrained generation scheduling for 24 hours. However, the way line flow and bus voltage have been considered is not shown.

In [24] MILP technique is applied for generation and line scheduling for every hour together. However, this may be suitable only for special systems with sufficient redundancy in line and generation assets. In many practical systems these two are independently scheduled.

In [63] a MILP based scheduling method considering cycling cost in addition to fuel cost for the thermal units has been proposed. The cycling cost takes into account the stress due to switching the thermal units ON or OFF due to electricity market mode of operation and fluctuation of the outputs from renewable based generation units interfaced with a grid system. However, voltage constraints are not considered in this work.

In [78] a MILP based combined scheduling and dispatching technique suitable for a small and isolated power system is presented. Moreover, voltage constraint has not been considered.

3.4.3 Stochastic MILP variants of Lagrange Relaxation Method

In stochastic scheduling [33, 69] some of the generation unit or load parameters are considered to have statistical variation and modeled accordingly. However, in general the probability distribution of uncertain parameters is difficult-to-obtain.

In [33] a method has been proposed for a very special case where thermal units with large start up costs, long start up and minimum up time are difficult to be scheduled in 24 hours period. Those can be selected only if a week long scheduling is done. But availability of units over one week is stochastic. So this stochastic feature was considered while coordinating the results of a 24 hrs period scheduling with one week long scheduling. However, in many practical power systems such slow thermal units are coordinated using much simpler procedures for a 24 hrs period. Furthermore, the method [33] does not address the voltage problem in the scheduling.

In [69] the uncertainty of generation and load at a bus was considered in a deterministic way while solving the scheduling problem. However, bus voltages were not considered in the method.

3.5 Evolutionary Algorithm based Scheduling

Evolutionary algorithms [15, 26, 27, 39, 51, 61, 65, 71] for scheduling use genetic algorithm (GA), simulated annealing, particle swarm optimization (PSO) and their variants. These methods begin with an initial solution vector with binary elements i.e. assume 0 or 1for the status of various units arbitrarily. Then the acceptability of the solution is evaluated by a fitness function which requires the status of the generation units as inputs. If not acceptable these solution vector (status) is updated heuristically (i.e. not based on rigorous mathematics) using various techniques as the names imply. The general problems of these methods are inaccuracy and limitation to test a large number of populations i.e. to explore the whole solution space and inability to use any network matrix.

In [15] the reported method uses, instead of a binary vector, a quantum bit string represented by two variables α and β which rotate over a circular locus at different angles such that sum of their squares is 1. This ensures exploration of the whole solution space with a less number of populations. The acceptability of the solution vector is tested using the sum of the cost function of the units. However, the method is unable to consider the most difficult coupling constraint i.e. bus voltage. This is the reason no network parameters of the test systems are available. Moreover, the method was tested for higher number of generation units simply by duplicating the cost characteristics and capacity data for a basic 10 unit system. This makes the method applicable only for a group of generation units without any diverse cost characteristics.

The work [26] is similar to [15] but differs only in that the quantum string is updated using PSO technique. However, optimization using voltage constraint was not done.

In [27] a variant of PSO is proposed in which instead of single binary data (0 and 1) for every unit, variable dimension of binary numbers are used to indicate the status for different units over 24 hours. This helps represent the differences in the operational characteristics of the units properly and speed up the solution time due to reduced number of searches. However, the limitations of this method are similar to that reported in [15].

In [39] the PSO technique is applied with a provision to apply mutation i.e. status of two randomly selected generation units so that local minimum condition can be avoided. However, its limitations including inability to optimize considering voltage constraint, are the same as those for the other PSO methods.

In [51] a method similar to genetic algorithm is proposed with a difference that instead of binary variables (0,1) integer variables are used to code the initial solution vector. However, its limitations are the same as those for the other evolutionary methods.

In [61] fuel cost, emission and reliability level are optimized simultaneously using artificial bee colony algorithm and fuzzy logic coded values for the generation outputs. However, voltage constraint was not considered.

In [65] a method combining PSO and differential evolution (mutation, selection and crossover) is proposed to schedule generation units but without considering bus voltage magnitudes.

In [71] a new evolutionary programming technique is proposed. In this the population variables are normal real variables and termed learners. From these the ones which best satisfy the fitness function, are updated as teachers. However, bus voltage was not included in its constraints set.

3.6 Drawbacks of Existing Scheduling Methods

It appears that the methods reported in the literature so far keep the scheduling stage very simple. Those consider only the fuel cost characteristics and hourly load balancing constraint over 24 hours while transmission loss and the security related constraints such as bus voltage limits, line flow limits and contingencies are checked in the hour wise dispatching stage. This may lead to selection of the units unlikely to improve system wide voltage and transmission loss. This is because bus voltages depend upon the combined outputs of all the units that are selected in an hour and it cannot be improved much if the most relevant units are not selected. The consequences of low voltage may also necessitate load shed else voltage instability leading to system collapse and increased transmission loss will result. So at the scheduling (selection) stage a voltage criterion should be incorporated into the optimization function. If bus voltages improve then the transmission lines' loading and losses are also expected to reduce.

However, it has been observed that among all the existing methods for generation scheduling the most accurate and amenable to systematic change is the Lagrange Relaxation (LR) method. This is the reason classical LR is used to benchmark other methods.

On the other hand the evolutionary methods converge fast but results in inaccurate solution due to their heuristic way of handling the generation scheduling problem.

However, neither the classical Lagrange Relaxation method nor other existing methods for generation scheduling consider bus voltage and transmission loss in the cost function for selection of generation units over 24 hours. So the present research aims at bridging this gap of the existing methods.

3.7 Overview of Classical Lagrange Relaxation Method

Since the LR method for generation scheduling is considered in the literature as the benchmark for other methods, for a ready reference a brief overview of this method is given in what follows.

The prime objective function F_T is total of fuel cost plus start up costs of the units to be selected for each interval t in a total period of N_t.

Minimize

$$F_T\left({P_{gi}}^t, {U_i}^t\right) = \sum_{t=1}^{N_t} \sum_{i=1}^{N} \left[F_i\left(P_{gi}^t\right) + S U {C_i}^t\right] U_i^t \tag{3.1}$$

subject to

$$P_{load}^t - \sum_{i=1}^{N} P_{gi}^t U_i^t = 0 \tag{3.2}$$

where ,

$t=1,2,3\ldots\ldots N_t$; is any interval (hour)

N_t is total number of intervals for scheduling and usually equal to 24

N= total number of units available for commitment in each of N_t intervals

$P_{gi}{}^{t}$ = output (MW) of generation unit i in the interval t

$U_i{}^{t}$ = status of the unit i in interval t which will be either 0 (if not selected i.e. OFF status) or 1 (if selected i.e. ON status)

$$F_i(P_{gi}^t) = \frac{a_i}{2} P_{gi}^{t\,2} + b_i P_{gi}{}^{t} + c_i \tag{3.3}$$

is the fuel cost (\$/h) incurred by unit i in interval (hour) t and usually [1] a parabolic function of the output $P_{gi}{}^{t}$ with coefficients a,b,c that depend upon type of fuel used and the design of the unit

$SUC_i{}^{t}$ = start up cost of unit i in interval t

$P_{load}{}^{t}$ = total system load (MW) in interval t

The term relaxation refers to considering a constraint as a part of the objective (or cost) function instead of considering it as a separate constraint. The Lagrange function to be minimized is formed from equations (3.1) to (3.3) as follows.

$$L = \sum_{t=1}^{N_t} \sum_{i=1}^{N} \left[F_i(P_{gi}^t) \ + \ SUC_i{}^{t}\right] U_i^t + \sum_{t=1}^{N_t} \lambda^t \left(P_{load}^t - \sum_{i=1}^{N} P_{gi}^t U_i^t\right) \tag{3.4}$$

where,

λ^t = Lagrange multiplier in interval t in unit of **\$/MWh or \$/h/MW**. Its physical significance is that it is the system wide average cost per hour to adjust the output (MW) of the generation units selected in interval t to meet the demand plus loss in the same interval

The Lagrange function of equation (3.4) is optimized using a two step i.e. dual optimization [1] procedure involving an iterative sequence. First the Lagrange multipliers (λ^t) are so updated that those will move the L function towards a higher value and then keeping this λ fixed in the same iteration other variables ($P_{gi}{}^{t}$, $U_i{}^{t}$) are so updated that the L function moves towards a lower value. The iteration process is terminated when the absolute value of the duality gap (J- q)/q is significantly small. The function J termed primal value is only the first term (i.e. sum of fuel and start up costs of units scheduled in each hour) in the right side of equation (3.4) while the function q termed dual value is L itself i.e. the whole right side of equation (3.4).

$$J = \sum_{t=1}^{N_t} \sum_{i=1}^{N} \left[F_i\left(P_{gi}^{t}\right) + SUC_i{}^{t} \right] U_i^{t} \tag{3.5}$$

$$q=L \tag{3.6}$$

At the end of the iterative process L function is the maximum with respect to λ while the minimum with respect to $P_{gi}{}^{t}$ and $U_i{}^{t}$.

3.7.1 Load Allocation by OPF

Dispatching or load allocation is not an integral part of scheduling. After the generators are selected for each hour of the time horizon (usually 24 hours) by any scheduling method, load allocation among the scheduled units can be done by the optimal power flow (OPF) solution. The OPF is also reviewed briefly in what follows for the sake of completeness.

To allocate the load on an individual hour (t) basis, the OPF uses only the generation units scheduled for the hour t i.e. which have been assigned $U_i{}^{t}$ =1 status by a scheduling method. It optimizes the cost function comprising only those generators.

The general framework of OPF [1, 2] is as follows.

Minimize

$$f_t\left(P_{gi}{}^{t}, U_i{}^{t}\right) = \sum_{i=1}^{N} \left[F_i\left(P_{gi}^{t}\right) \right] U_i^{t} \tag{3.7}$$

subject to

$$g(x,u,w)=0 \tag{3.8}$$

$$u_{min} \le u \le u_{max} \tag{3.9}$$

$$h(x,u) \le 0 \tag{3.10}$$

where,

$F_i(P_{gi}^t)$ is as in equation (3.3) but only the units, for which the scheduling method has assigned the status variable U_i^t =1 (i.e. ON status), are considered in OPF.

The x variables are the bus voltage magnitudes of only load connected buses and phase angles of all buses excepting the slack bus. The x variables are not involved directly in the cost function.

The u values comprise adjustable variables i.e. bus voltage magnitudes and real power outputs of the generators (P_{gi} ; i=1,2…..N).

The g functions are the balance between generation and load at each bus and hence the set of load flow equations [81] as shown in equations (3.11) and (3.12) which are functions of x, u, w (line parameters i.e. G, B data) variables.

$$P_i(V,\theta)=V_i\sum_{j=1}^{N_b}\left[V_j\left(G_{ij}\cos\theta_{ij}\ +\ B_{ij}\sin\theta_{ij}\right)\right] \tag{3.11}$$

$$Q_i(V,\theta)=V_i\sum_{j=1}^{N_b}\left[V_j\left(G_{ij}\sin\theta_{ij}-\ B_{ij}\cos\theta_{ij}\right)\right] \tag{3.12}$$

The h functions are a set of inequality constraints such as upper and lower limits of the load connected bus voltage magnitudes, line flow limits, generator active and reactive power limits etc.

Then an unconstrained objective function as follows is formed to solve OPF.

$$L(x,u,w)=f(x,u)+\lambda^T g(x,u,w) \tag{3.13}$$

where λ is a vector of m number of multipliers if there are m number of equality constraints.

Now L will be minimum if the following gradients (derivatives) with respect to x, u, λ become zero.

$$\nabla L_x = \frac{\partial L}{\partial x} = \frac{\partial f}{\partial x} + \left[\frac{\partial g}{\partial x}\right]^T \lambda = 0 \tag{3.14}$$

$$\nabla L_u = \frac{\partial L}{\partial u} = \frac{\partial f}{\partial u} + \left[\frac{\partial g}{\partial u}\right]^T \lambda = 0 \tag{3.15}$$

$$\nabla L_\lambda = \frac{\partial L}{\partial \lambda} = g(x, u, w) = 0 \tag{3.16}$$

Then the OPF problem is usually solved using the gradient method [1] also known as steepest descent method as follows.

i) A set of initial values are assumed for u variables.

ii) Equation (3.16) is solved which is same as a power flow (load flow) analysis to obtain x variables. This will involve [∂g/∂x] which is the load flow Jacobian matrix.

iii) From equation (3.14) λ is obtained as follows

$$\lambda = -\left[\left(\frac{\partial g}{\partial x}\right)^T\right]^{-1} \frac{\partial f}{\partial x} \tag{3.17}$$

iv) λ values are substituted in equation (3.15) to compute the gradient of L with respect to control variables i.e.

$$\nabla L_u = \frac{\partial f}{\partial u} - \left[\frac{\partial g}{\partial u}\right]^T \left\{\left[\left(\frac{\partial g}{\partial x}\right)^T\right]^{-1} \frac{\partial f}{\partial x}\right\} \tag{3.18}$$

v) Update control variables u as follows.

$$u^{k+1} = u^{k} - \gamma \nabla L_{u} \tag{3.19}$$

where γ is step size usually equal to 1 for generation cost minimization.

After solving for control variables the constraints are checked. If the value of any u variable reaches the limit then that is set at its maximum or minimum limit whichever is violated. Then the next iteration is continued with remaining u variables as usual i.e. a reduced set of u variables. If any inequality constraint is violated it is easier to set it at its maximum or minimum limit whichever is violated and then considered as a new g (equality) constraint.

Thus the sequence starting from step (ii) to (v) is repeated until change in u between two successive iterations is less than or equal to a tolerance margin.

3.8 Conclusion

A good deal of work reported in literature for generation scheduling has been critically reviewed. It has been observed that among all the existing methods for generation scheduling the most accurate and amenable to systematic change is the Lagrange Relaxation (LR) method. On the other hand various evolutionary methods converge fast but results in inaccurate solution due to their heuristic way of handling the generation scheduling problem. This is the reason classical LR is used to benchmark other methods.

Once the generation units are scheduled using any method, hourly load can be allocated (dispatched) among the units scheduled for that hour using the optimal power flow (OPF) solution.

However, neither the classical Lagrange Relaxation method nor other existing methods for generation scheduling consider bus voltage and transmission loss in the cost function for selection of generation units over 24 hours. These are considered by OPF indirectly on individual hour basis after the generators are selected by the scheduling method. But if these were considered by a scheduling method the selection would have been different and optimized. So the present research aims at bridging this gap of the existing methods.

For this it is necessary to incorporate voltage magnitudes constraint and transmission loss in the scheduling method. This is possible if bus voltage magnitudes and transmission loss in each hour can be related to the outputs of the units being evaluated for scheduling and embedded in the overall cost function. This is proposed in the present research and Chapter 4 shows the methodology for this.

Chapter 4 Proposed Methodology

This chapter focuses on the mathematical details in the development process of the proposed method. In this method the generation units are selected based on not only their cost characteristics and the hourly system load but also on their impacts on system wide bus voltages and the transmission loss.

4.1 Introduction

In the classical Lagrange relaxation method used in generation scheduling the prime objective function (i.e. total fuel cost) is minimized subject to the load balance constraint (i.e. total generation equals system demand) through a dual optimization procedure as mentioned in Sec. 3.7. This leads to selection (scheduling) of relatively low fuel cost units in each hour from among the available units and then the hourly system load is allocated among only these selected units subject to various operating and network related constraints through an optimal power flow (OPF). But as mentioned in Sec. 2.3 this may give rise to a problem of low voltage at the locations far away from the cheaper units which have been selected. This is because reactive power flow from generators to loads over a longer distance entails excessive voltage drop. Also this will increase the currents in the lines from generators to loads and hence the transmission loss. As the voltages and transmission losses are not considered in the classical Lagrange optimization function, the units likely to improve voltage at farther locations and reduce overall transmission loss may remain unselected.

For maintaining an improved voltage magnitude profile and reducing loss, some generation units which are nearer to the load centres should be selected right at the scheduling stage even though those units may have higher operating costs. In the proposed scheduling method the Lagrange function embeds in it all the bus voltage magnitudes besides the generation and load balance. The effect of transmission loss is also incorporated in the modified Lagrange function by considering the loss to be a typical percentage of the total power output of the units that will be selected in the scheduling process. As a result the units which can improve voltage and reduce loss are expected to be scheduled in each interval (hour). Section 4.2 shows the way the proposed method is developed.

After the proposed method schedules the generation units in each hour of the total time horizon, OPF can be applied as mentioned in Sec. 3.7.1 for hour wise allocation of the load among the units scheduled in each hour.

4.2 Developing the Model for the Proposed Method

In this method the prime objective function F_T (total of fuel costs plus start up costs of the units to be scheduled for each of N_t intervals) shown by equation (4.1) is used. As the objective now is to optimize the fuel cost to maintain not only generation and load balance but also an acceptable voltage profile and a typical transmission loss, so the scheduling model is as follows.

Minimize

$$F_T\left({P_{gi}}^t, {U_i}^t\right) = \sum_{t=1}^{N_t} \sum_{i=1}^{N} \left[F_i\left(P_{gi}^t\right) + {SUC_i}^t\right] U_i^t \tag{4.1}$$

subject to

$$P_{load}^t - (1 - p) \sum_{i=1}^{N} P_{gi}^t U_i^t = 0 \tag{4.2}$$

$$\sum_{b=1; b \neq slack}^{N_b - 1} (1.0 - |V_b^t|) = 0 \tag{4.3}$$

where,

Equation (4.2) shows the load balance constraint i.e. total output of units to be selected in each hour should equal the load plus loss.

Equation (4.3) shows the bus voltage constraints i.e. in each hour the voltage magnitude should be around 1.0 per unit (pu) at all buses excepting the one labeled as the slack bus for which a pre-specified bus voltage is maintained.

$t=1,2,3\ldots\ldots N_t$; is any time interval (hour)

N_t is total number of intervals for scheduling and usually equal to 24

N= total number of units available for commitment in each of N_t intervals

P_{gi}^{t} = output (MW) of generation unit i in the interval t

U_i^t = status of the unit i in interval t which will be either 0 (if not selected i.e. OFF status) or 1 (if selected i.e. ON status)

p = ratio of transmission loss in an interval to the sum of the outputs of the units selected in the same interval

$$F_i\left(P_{gi}^t\right) = \frac{a_i}{2} P_{gi}^{t\,2} + b_i {P_{gi}}^t + c_i \tag{4.4}$$

is the fuel cost incurred by unit i in interval t as mentioned in Sec. 3.7.

SUC_i^t = start up cost of unit i in interval t

$P_{load}^{\ t}$ = total system load (MW) in interval t

$|V_b^t|$ = voltage magnitude at bus any bus b (not equal to slack bus) in interval t with ground bus as the reference

N_b= total number of buses =($N + N_{Lb}$)

N = number of generator connected buses

N_{Lb} = number of only load connected buses

Equations (4.1) to (4.3) show that for minimization a Lagrange function can be formed as

$$L = \sum_{t=1}^{N_t}\sum_{i=1}^{N}[F_i(P_{gi}^t) + SUC_i{}^t]U_i^t + \sum_{t=1}^{N_t}\lambda^t\left(P_{load}^t - (1-p)\sum_{i=1}^{N}P_{gi}^tU_i^t\right) + \sum_{t=1}^{N_t}\mu^t\left(\sum_{b=1;b\neq slack}^{N_b-1}(1.0-|V_b^t|)\right) \tag{4.5}$$

where,

λ^t = Lagrange multiplier in interval t in unit of **\$/MWh or \$/h/MW**. Its physical significance is the same as that mentioned in Sec. 3.7.

μ^t = Another Lagrange multiplier in interval t in unit of **\$/h/pu voltage difference**. Its physical significance is that it is the system wide average cost per hour to adjust the reactive power output of the generation units selected in interval t so that voltage magnitudes at the buses become approximately 1.0 pu. In market environment μ^t would imply the average cost for the generators giving VARs support instead of real power in an interval t.

Equation (4.5) can be simplified as (4.6) in terms of a single Lagrange multiplier by considering the cost of voltage adjustment through reactive power output, as a fraction of the generation units' real power output adjustment cost i.e. $\mu = x\lambda$.

$$L = \sum_{t=1}^{N_t}\sum_{i=1}^{N}[F_i(P_{gi}^t) + SUC_i{}^t]U_i^t + \sum_{t=1}^{N_t}\lambda^t\left(P_{load}^t - (1-p)\sum_{i=1}^{N}P_{gi}^tU_i^t\right) + \sum_{t=1}^{N_t}x\lambda^t\left(\sum_{b=1;b\neq slack}^{N_b-1}(1.0-|V_b^t|)\right) \tag{4.6}$$

Now bus voltages are coupled type constraint i.e. each bus voltage is impacted by current injections I at more than one buses depending upon the network configuration. In order to take this effect into account in the proposed method, the bus voltage vector [V] required in equation (4.6) in each interval t is computed using a matrix [Z] as in equation (4.7) when the slack bus voltage is pre-specified.

$$[V] = [Z][I] + [1\ \ 1\ \ 1 \ldots\ldots\ldots 1]^{Transpose}V_{slack} \tag{4.7}$$

The matrix [Z] is a square matrix and of order (N_b-1) to be formed from the usual bus impedance matrix [80] excluding the row and column corresponding to the slack bus and considering all connections from a bus to the ground (i.e. shunt reactor/capacitor and line charging susceptances) as disconnected. However, for convenience henceforth [Z] will be termed bus impedance matrix. In fact the shunt susceptance (jy_{sh}) effects are modeled as a negative injected current at the corresponding bus as shown in equation (4.8).

Equation (4.7) can be segregated for each bus voltage (phasor) at a bus b (=1,2…..N_b; b ≠ slack) in interval t as in equation (4.8).

$$V_b^t = \sum_{\substack{i=1 \\ i\neq slack}}^{N} Z_{bi}\left(I_i^t - jy_{sh,i}V_i^t\right) + \sum_{k=1}^{N_{Lb}} Z_{bk}\left(I_k^t - jy_{sh,i}V_i^t\right) + V_{slack} \tag{4.8}$$

where,

i ϵ {N number of generator connected buses}

k ϵ { N_{Lb} number of only load connected buses}

$y_{sh,i}$ = total shunt admittance (pu) at bus i including charging susceptance, external reactor/capacitor

I_i^t = current injection in pu at the bus of generation unit No. i in interval t

I_k^t =current injection in pu at the bus where only load k is connected in interval t

V_{slack} = pre-specified slack bus voltage phasor i.e. magnitude and phase angle

Z_{bi} = R_{bi}+jX_{bi} is the element (in pu) between bus b and the bus of generator i in the bus impedance matrix [Z]

Z_{bk} = R_{bk}+jX_{bk} is the element (in pu) between bus b and the bus of load k in the bus impedance matrix [Z]

The current injections I at generator connected buses and only load connected buses in interval t are respectively as in equations (4.9) and (4.10).

$$I_i{}^t = \frac{1}{MVA_{base}}\left(\frac{P_i^t + jQ_i^t}{V_i{}^t}\right)^* \tag{4.9}$$

$$I_k{}^t = \frac{1}{MVA_{base}}\left\{\frac{-\left(P_{dk}^t + jQ_{dk}^t\right)}{V_k^t}\right\}^* \tag{4.10}$$

where,

$$P_i^t = P_{gi}^t U_i^t - P_{di}^t \tag{4.11}$$

is real power (MW) injection at the bus of generation unit No. i (i.e. difference of generator real power output P_{gi} and real load, P_{di} , if any, at bus of unit i) in interval t

$$Q_i^t = Q_{gi}^t U_i^t - Q_{di}^t \tag{4.12}$$

is reactive power (MVAR) injection at the bus of generation unit No. i (i.e. difference of generator reactive power output Q_{gi} and reactive load Q_{di}, if any, at bus of unit i) in interval t

MVA_{base} = Base MVA

$P_{dk}{}^t$ = real load (MW) in interval t at the bus where only load k is connected

$Q_{dk}{}^t$ = reactive load (MVAR) in interval t at the bus where only load k is connected

Equation (4.8) can be rewritten as (4.13) and then (4.14).

$$V_b{}^t = \sum_{\substack{i=1 \\ i\neq slack}}^{N} \left[Z_{bi} \frac{1}{MVA_{base}} \left(\frac{(P_{gi}^t U_i^t - P_{di}^t) + j(Q_{gi}^t U_i^t - Q_{di}^t)}{V_i{}^t} \right)^* - \mathrm{Z_{bi}}\left(\mathrm{jy_{sh,i}}\,\mathrm{V_i}^{\mathrm{t}}\right) \right] + \sum_{k=1}^{N_{Lb}} \left[Z_{bk} \frac{1}{MVA_{base}} \left\{ \frac{-(P_{dk}^t + jQ_{dk}^t)}{V_k^t} \right\}^* - \mathrm{Z_{bk}}\left(\mathrm{jy_{sh,k}}\,\mathrm{V_k}^{\mathrm{t}}\right) \right] + V_{slack} \tag{4.13}$$

or,

$$V_b{}^t = \sum_{\substack{i=1 \\ i\neq slack}}^{N} \left[Z_{bi} \frac{1}{MVA_{base}} \frac{(P_{gi}^t U_i^t - P_{di}^t)}{V_i^{t*}} (1 - js_i) - \mathrm{Z_{bi}}\left(\mathrm{jy_{sh,i}}\,\mathrm{V_i}^{\mathrm{t}}\right) \right] + \sum_{k=1}^{N_b} \left[-Z_{bk} \frac{1}{MVA_{base}} \frac{P_{dk}^t}{V_k^{t*}} (1 - js_k) - \mathrm{Z_{bk}}\left(\mathrm{jy_{sh,k}}\,\mathrm{V_k}^{\mathrm{t}}\right) \right] + V_{slack} \tag{4.14}$$

where,

$$\frac{(Q_{gi}^t U_i^t - Q_{di}^t)}{(P_{gi}^t U_i^t - P_{di}^t)} = s_i = \tan\left(cos^{-1}(pf_i)\right) \tag{4.15}$$

$$\frac{{Q_{dk}}^t}{{P_{dk}}^t} = s_k = \tan\left(cos^{-1}(pf_k)\right) \tag{4.16}$$

pf_i and pf_k are respectively power factor at buses i and k

Now in each hour t, V_b^t in equation (4.14) can be expressed as two parts i.e. P_{gi} dependent and C_b which is P_{gi} independent.

$$V_b^t = \sum_{\substack{i=1 \\ i\neq slack}}^{N} \left[Z_{bi}\frac{1}{MVA_{base}}\frac{(P_{gi}^t U_i^t - P_{di}^t)}{V_i^{t*}}(1-js_i)\right] + C_b \tag{4.17}$$

where,

$$\mathrm{C_b} = \sum_{\substack{\mathrm{i=1} \\ \mathrm{i\neq slack}}}^{\mathrm{N}} \left[-\mathrm{Z_{bi}}\left(\mathrm{jy_{sh,i}}\,{\mathrm{V_i}}^{\mathrm{t}}\right)\right] + \sum_{\mathrm{k=1}}^{\mathrm{N_{Lb}}}\left[-Z_{bk}\frac{1}{MVA_{base}}\frac{P_{dk}^t}{V_k^*}(1-js_k) - \mathrm{Z_{bk}}\left(\mathrm{jy_{sh,k}}\,{\mathrm{V_k}}^{\mathrm{t}}\right)\right] + V_{slack} \tag{4.18}$$

Then the magnitude of V_b^t given by equation (4.17) can be simplified as in equation (4.19) without loss of accuracy.

$$|V_b^t| \cong \sum_{\substack{\mathrm{i=1} \\ \mathrm{i\neq slack}}}^{N} \frac{1}{MVA_{base}}\sqrt{1+{s_i}^2}\,|Z_{bi}|\,\left|{V_i}^t\right|^{-1}(P_{gi}^t U_i^t - P_{di}^t) + |C_b| \tag{4.19}$$

That accuracy is not lost in this way can be seen from an example.

Let it be assumed that a phasor V=A+B when A=2+j3 and B=3+j4 so that

$|V| = |A+B| = |(2+j3)+(3+j4)| = |(5+j7)| = \sqrt{74} = 8.6023$

But, $|A| + |B| = |(2+j3)| + |(3+j4)| = \sqrt{13} + \sqrt{25} = 8.6055$

So $|V| = |A+B| \cong |A| + |B|$, in fact for any values of phasors A and B, which supports equation (4.19).

Equations (4.6) and (4.19) can now be combined to form (4.20).

$$L = \sum_{t=1}^{N_t}\sum_{i=1}^{N}\left[F_i\left(P_{gi}{}^{t}\right) + SUC_{i,t}\right] U_i^t + \sum_{t=1}^{N_t}\left\{\lambda^t\, P_{load}^t + \; x\lambda^t \sum_{b=1}^{N_b-1}(1.0 - |C_b|)\right\}$$
$$- \sum_{t=1}^{N_t} x\lambda^t \sum_{b=1}^{N_b-1}\left\{\sqrt{1+{s_i}^2}\sum_{\substack{i=1\\ i\neq \text{slack}}}^{N} |Z_{bi}|\left|V_i{}^t\right|^{-1}\left(P_{gi}^t U_i^t - \; P_{di}^t\right)\right\} - (1-p)\sum_{t=1}^{N_t}\sum_{i=1}^{N}\lambda^t P_{gi}^t U_i^t$$

(4.20)

It should be noted that the MVA_{base} quantity need not be used in the third term on the right side of equation (4.20) because the product λ^t $(P_{gi}{}^t\text{-}P_{di}{}^t)$ is now in \$/h and consistent with the unit of the Lagrange function which is also in \$/h for each individual interval t.

4.2.1 Solving for Lagrange multiplier, generation unit status and output in each hour

As mentioned for the classical Lagrange method in Sec. 3.7, the Lagrange function of the proposed method will also be optimized using a two step i.e. dual optimization procedure in each iteration.

First the Lagrange multipliers (λ^t) for each hour t, are so updated that those will move the L function towards a higher value. Then keeping this λ fixed in the same iteration other variables ($P_{gi}{}^t$, $U_i{}^t$) for each hour t, are so updated that the L function moves towards a lower value.

In each iteration the magnitudes of bus voltages $|V_b|$ (excepting the slack bus) to be used in equation (4.6) are obtained for each hour from equation (4.14) using another internal iterative loop because of the presence of the same voltage term on both sides of equation (4.14).

The function J termed primal value and the function q termed dual value are computed respectively by equations (4.21) and (4.22).

$$J = \sum_{t=1}^{N_t}\sum_{i=1}^{N}\left[F_i\left(P_{gi}^t\right) \; + \; SUC_i{}^t\right]U_i^t$$

(4.21)

$$q=L \qquad (4.22)$$

It should be noted that L in equation (4.22) is the same as the Lagrange function given by equation (4.6).

The iteration process is terminated when the absolute value of the duality gap (J- q)/q is significantly small. At the end of the iterative process L function is the maximum with respect to λ while the minimum with respect to P_{gi}^t and U_i^t.

<u>λ updating:</u>

In each iteration k, updating the Lagrange multiplier λ for each hour t requires computation of the $\frac{dq}{d\lambda^t}$ function. So the right side of equation (4.6) is differentiated with respect to λ^t to obtain $\frac{dq}{d\lambda^t}$ for use in equation (4.23) leading to (4.24).

$$(\lambda^t)^k = (\lambda^t)^{k-1} + \left[\frac{dq}{d\lambda^t}\right]^{k-1} \alpha \tag{4.23}$$

$$(\lambda^t)^k = (\lambda^t)^{k-1} + \alpha\{\left(P_{load}^t - (1-p)\sum_{i=1}^{N} P_{gi}^t U_i^t\right) + x \sum_{\substack{b=1 \\ b\neq slack}}^{N_b-1} (1.0 - |V_b^t|)\} \tag{4.24}$$

where α is the step size which is assigned a higher value if the second term inside {} on the right side of equation (4.24) turns to be positive while assigned a less value if the same quantity becomes negative.

<u>Generation unit status and output updating:</u>

Having updated λ^t the values of P_{gi}^t and U_i^t for each hour t are to be updated in the same iteration k. For this only the P_{gi}^t and U_i^t involved terms are taken from equation (4.20) to form equation (4.25).

$$\mathcal{L} = \sum_{t=1}^{N_t}\sum_{i=1}^{N}\left[F_i\left(P_{gi}{}^t\right) + SUC_i{}^t\right] U_i^t - \sum_{t=1}^{N_t} x\lambda^t \sum_{b=1}^{N_b-1}\left\{\sqrt{1+s_i{}^2}\ \sum_{\substack{\mathrm{i=1}\\ \mathrm{i\neq slack}}}^{N} |Z_{bi}|\left|V_i{}^t\right|^{-1} P_{gi}^t U_i^t\right\} - (1-p)\sum_{t=1}^{N_t}\sum_{i=1}^{N}\lambda^t P_{gi}^t U_i^t \tag{4.25}$$

It should be noted that equation (4.25) can be rewritten unit wise as (4.26) and used separately to minimize $\mathcal{L}$ with respect to each unit in each hour and hence update each generation unit's status U_i^t and output P_{gi}^t. It should be noted that in equation (4.26) for the slack bus connected generation unit (i=slack) the term $\sum_{b=1}^{N_b-1}|Z_{bi}|$ is zero.

$$\mathcal{L} = \sum_{i=1}^{N}\sum_{t=1}^{N_t}\left\{F_i\left(P_{gi}{}^t\right)U_i^t + SUC_i{}^t U_i^t - x\lambda^t\left|V_i{}^t\right|^{-1} P_{gi}^t U_i^t \left\{\sqrt{1+s_i{}^2}\ \sum_{b=1}^{N_b-1}|Z_{bi}|\right\} - (1-p)\lambda^t P_{gi}^t U_i^t\right\} \tag{4.26}$$

Now $\mathcal{L}$ will be minimum if the derivative of right side of (4.26) with respect to a generation unit i becomes zero in hour t provided $U_i^t=1$.

$$\frac{d}{dP_{gi}^t}\left[F_i\left(P_{gi}{}^t\right) + SUC_i{}^t - (1-p)\lambda^t P_{gi}^t - x\lambda^t P_{gi}^t |V_i|^{-1}\sqrt{1+s_i{}^2}\sum_{b=1}^{N_b-1}|Z_{bi}|\right] = 0$$

or, (4.27)

$$\frac{dF_i\left(P_{gi}^t\right)}{dP_i^t} - (1-p)\lambda^t - x\lambda^t|V_i|^{-1}\sqrt{1+s_i{}^2}\sum_{b=1}^{N_b-1}|Z_{bi}| = 0$$

or,

$$\frac{d}{dP_{gi}^t}\left(\frac{a_i}{2}P_{gi}^{t2} + b_i P_{gi}^t + c_i\right) - (1-p)\lambda^t - x\lambda^t\frac{\sqrt{1+s_i{}^2}}{|V_i|}\sum_{b=1}^{N_b-1}|Z_{bi}| = 0$$

or,

$$a_i P_{gi}^t + b_i - (1-p)\lambda^t - x\lambda^t \frac{\sqrt{1+{s_i}^2}}{|V_i|} \sum_{b=1}^{N_b-1} |Z_{bi}| = 0$$

or,

$$P_{gi}^t = \frac{\lambda^t \left((1-p) + x \frac{\sqrt{1+{s_i}^2}}{|V_i|} \sum_{b=1}^{N_b-1} |Z_{bi}| \right) - b_i}{a_i} \; ; \; P_{gi}^{Min} \le {P_{gi}}^t \le P_{gi}^{Max}$$

(4.28)

$$P_{gi}^t = P_{gi}^{Max}; {P_{gi}}^t \ge P_{gi}^{Max}$$

$$P_{gi}^t = P_{gi}^{Min}; {P_{gi}}^t \le P_{gi}^{Min}$$

Thus (4.28) determines the outputs from units scheduled in hour t subject to their minimum and maximum capacities.

Now whether U_i^t is 1 or 0 i.e. whether in hour t the unit i need to be selected or not can be decided by substituting P_{gi}^t obtained from (4.28) in the right side of equation (4.26) for unit i and time t i.e.in the following expression.

$$\left\{ F_i\left({P_{gi}}^t\right) + {SUC_i}^t - (1-p)\lambda^t P_{gi}^t - x\lambda^t P_{gi}^t |V_i|^{-1} \sqrt{1+{s_i}^2} \sum_{b=1}^{N_b-1} |Z_{bi}| \right\}$$

If the above quantity turns out to be negative the Lagrange function will move towards the minimum with respect to i-th unit generation in hour t and hence U_i^t =1.

If the above quantity turns out to be positive the Lagrange function will move towards the maximum with respect to i-th unit generation in hour t and hence U_i^t =0.

It should be noted that the separable constraints mentioned in Sec. 3.1 i.e. minimum up or down time, ramp limitation etc. can always be considered in the proposed method at this stage. A check for violation of these constraints may override the U_i^t determined above i.e. keep a unit turned ON though U_i^t was determine to be 0 or OFF though U_i^t was determined to be 1.

4.3 Flow chart for the Proposed Method

A flow chart for the proposed method of scheduling the generation units is shown in Fig.4.1.

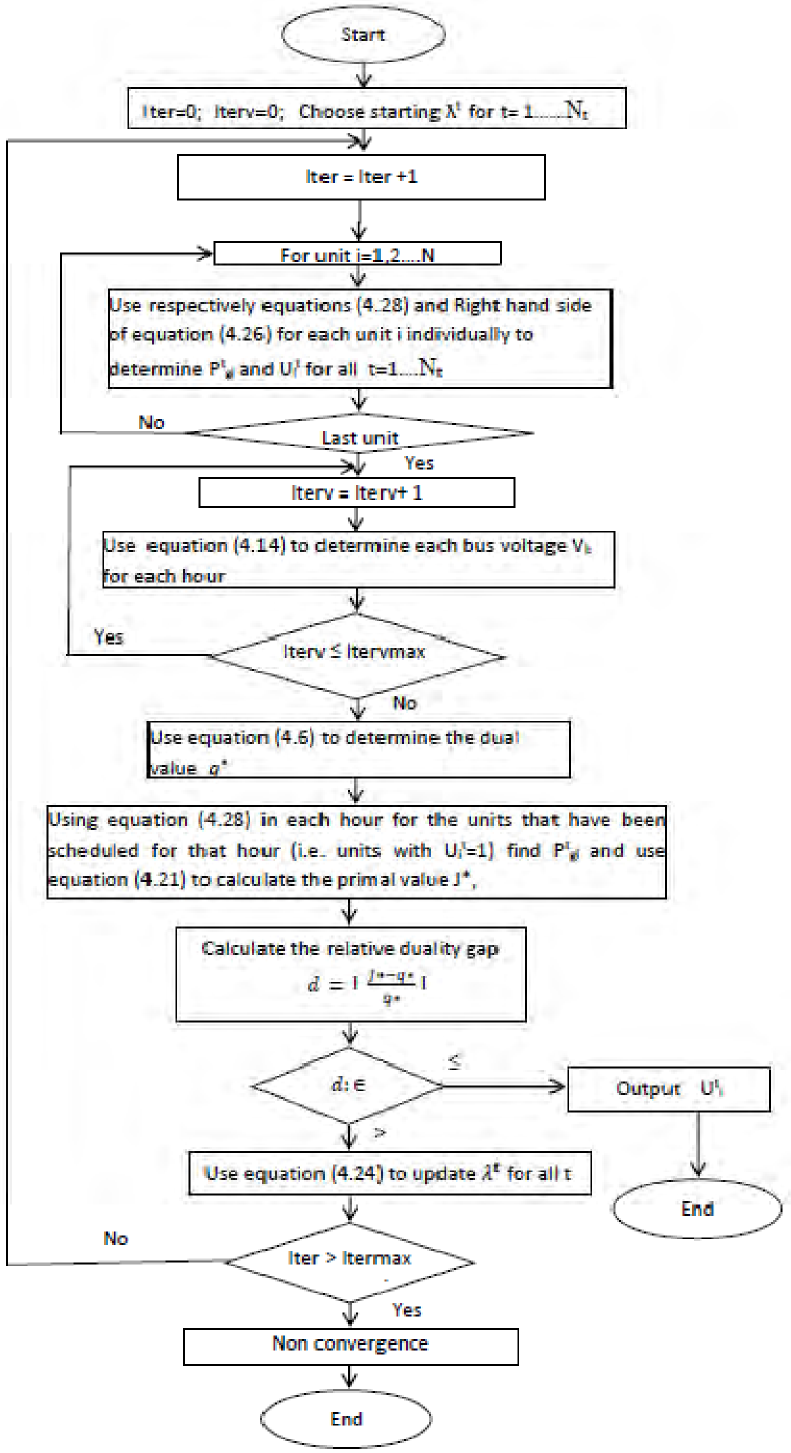

Fig. 4.1 Flow chart of the proposed generation scheduling method

4.4 Conclusion

In this chapter the way the proposed generation scheduling method is developed has been shown in details. The major difference of the proposed method from the classical Lagrange relaxation method is that right at the selection stage it (proposed) takes into account the impact of the units to be selected upon the transmission loss and the voltage magnitude of each bus in each interval. For this the voltage magnitude constraints and transmission loss are incorporated in the Lagrange function. The proposed method is expected to provide an optimum generation cost with an improved voltage profile and lower loss compared to the methods making only cost dependent selection of generation units. The validation of this is shown in Chapter 5. The OPF can be applied hour wise for load allocation among the scheduled units as usual after the proposed method completes the scheduling (selection) of the units for all the hours.

Chapter 5 Results and Discussion

This chapter illustrates the experimental approach for benchmarking the proposed method of generation scheduling against the classical Lagrange relaxation method. A comprehensive comparison considering various scenarios of system loads and fuel costs of the generation units in the standard IEEE 30 bus test system is shown. This chapter also demonstrates the potentials of the proposed method for a real-life system applying it in Bangladesh Power System (BPS).

5.1 Introduction

All the optimization based generation scheduling methods reported in the literature evolved out of the classical Lagrange method. However, depending upon the solution approach (e.g. linear or non linear programming, heuristic or evolutionary algorithms) and constraints, these methods diverge from one another. Some of the methods reported in the literature are not even fully described or not applied on standard test systems. It is difficult to program those and then apply on common test systems on same footing for a comparison of a new method. So the classical Lagrange method being the most systematic and tractable method is widely used as the reference for validation of an emerging method.

To validate the proposed method against the original Lagrange, the IEEE standard 30-bus test system has been used in this research. This system has long been accepted in the literature [10, 80] as the typical representative of the characteristics of a practical power system.

In addition to 30-bus system, a real-life system has also been used for further performance test. This is because a real-life system may not be always typical or similar to a standard system. Bangladesh Power System (BPS) is a live system typical of the countries marked with resource limitations. The problems facing such countries are limited sites of indigenous primary fuels (gas, coal, hydro), non-uniform location of generation units with respect to the load centres, and significant share of imported costly liquid fuel based generation units. However, a cost sensitive conventional scheduling method like the classical Lagrange relaxation method is unlikely to select from a given set the units having relatively higher production costs. In BPS the operators do not make any software assisted scheduling. They dispatch arbitrarily the oil based units in peak hours only which is not able to overcome low voltage problem. So to demonstrate the efficacy of a voltage sensitive generation scheduling method i.e. the proposed one in a real-life system, the BPS has been used in this research as an additional system of study.

As mentioned the scheduling methods differ from one another in the approaches to select the generation units for each hour of a time-horizon. So the impacts of the selection by two different scheduling methods upon the operation of a system can be more elaborately evaluated by running an OPF (Optimal Power Flow) after the scheduling is done. The input variables to OPF are the output variables (i.e. ON/OFF status of the units for an hour) of a scheduling method. Then the OPF allocates the load only among the units with ON status. Hence the same OPF code can be used to evaluate and compare the impacts of the selections by two different scheduling methods.

The results of the comprehensive simulation tests made in this research are presented mainly in the form of general comments while highlighting the outputs for typical demand patterns and representative variations in fuel cost parameters of generation units. A 24 hours time horizon is considered in all the simulations as is typical for any method of generation scheduling.

5.2 Experimental Approach

The computational experiments conducted in this research are described as follows. A core i5 PC having a clock speed of 3.3 GHz and an operating system Windows 8 has been used to do the simulations and comparisons of the proposed method against the classical Lagrange method of generation scheduling.

i). The proposed method and the classical Lagrange methods are applied separately on a test system considering the same set of hourly total loads and fuel cost parameters of the generation units. A maximum duality gap ($\in$) of 0.06 and a maximum number of iterations (‘itermax’) equal to 10 are used for both methods.

The proposed method requires additionally the individual bus loads (real and reactive) in each hour and the network parameters. Also it computes bus voltages using an internal iterative loop inside a main iteration. The maximum number of iterations (‘itervmax’) in this loop is set 5. The ratio (x) of the hourly average costs respectively to adjust reactive and real power is set 0.1

ii). Using the status of generation units obtained as outputs of the two methods, the OPF is run separately.

Both the proposed and the classical methods are applied on the IEEE standard 30-bus and 6-generation units system using steps (i) and (ii) considering a base load (100%) and then repeating it for respectively 110% , 120% and 130% of the base load (i.e. increasing the base load at every bus in each hour by 10%, 20% and 30%). Also the tests are repeated for each loading scenario considering three sets of fuel cost parameters (specifically the ‘b’ component i.e. $/MW/h or $/MWh) to investigate into the impact of fuel characteristics upon the performance of the two methods.

The proposed method and the classical Lagrange methods are tested on 166-bus and 93-generation units BPS using steps (i) and (ii) for a base load (100%) and another scenario of 110% loading. The same set of fuel cost parameters is considered in each loading scenario. BPS being a real-life system there is no scope to assume diverse set of fuel characteristics for the existing set of generation units.

5.2.1 Software

The Lagrange method selects a set of units from a given number of available generation units based on only the cost characteristics and hourly system load forecasted over a time horizon. It does not require a network model and locations of the loads. On the contrary, in addition to the total hourly load and generation cost parameters, the proposed method considers locations of generation units as well as individual load buses (substations) in a network. Also the magnitudes of bus loads for each hour and line parameters are considered by the proposed method.

To fulfill the above-mentioned requirements separate codes using MATLAB2012 have been developed in this research for the proposed method and the classical Lagrange method.

For an elaborate comparison of the impacts of generation units selection by two methods, the OPF software has been downloaded from a public domain [82].

5.3 Application in the IEEE 30 Bus Test System

IEEE 30 bus system, shown in Fig. 5.1, has a total of 30 buses of which 6 buses have generators connected to them. The buses are at 1 kV, 11 kV, 33 kV and 132 kV levels being connected by 37 transmission lines and 4 tie-transformers between different voltage level buses. The network data in per unit of 100 MVA are given in Sec. A.1 in Appendix A. The generation units' operational limits and quadratic cost characteristic's coefficients [10] are given in Table 5.1.

As mentioned in Sec. 2.1of Chapter 2, generation scheduling is done to cater to a forecasted load curve for 24 hours. Since this work focuses on scheduling so at simulation stage a 'forecasted' load profile may be assumed to be available. It should be noted that the base case total load and bus wise load available for the IEEE 30 bus test system in literature [10, 80] correspond to a peak hour only and is used for load flow or economic dispatch in that particular hour. However, it cannot be used for generation scheduling which requires total load for each of the 24 hours together. So in this work the load data have been derived for other 23 hours considering those to have a demand that follow a typical distribution expressed in percentage of the peak demand as shown in Fig. 5.2. The 'forecasted' base case total system load and bus wise load data (MW) for 24 hours in the 30 bus system are presented in Sec. A.2 in Appendix A. Notably the total load information for 24 hours is needed in the classical Lagrange method too.

For the individual buses, which basically represent the substations in a grid system, a typical load power factor of 0.85 lag [81] is considered so that reactive power demands are easily obtained. The generation units are also considered to be operating at 0.85 lagging power factor. The proposed method's model required the bus impedance matrix [Z] (= [R]+ j[X]) with the slack bus as the reference. This was duly formed in the way mentioned in Sec. 4.2 and the [R] and [X] matrices were integrated in the MATLAB code prepared for the proposed method. The elements of [R] and [X] matrices each of 29x29 order i.e. with the slack bus row and column eliminated, are given in Section A. 3 in Appendix A.

Table 5.1 Scheduling related data for the 6 units in IEEE 30 bus system

Unit serial No.	1	2	3	4	5	6
bus at which generation unit is connected	1	2	5	8	11	13
$P_{Gi\ max}$ (MW)	200	80	50	35	30	40
$P_{Gi\ min}$ (MW)	50	20	15	10	10	12
$a_i/2$ ($/MW^2/h)	0.00375	0.0175	0.0625	0.0083	0.0250	0.0250
b_i ($/MWh)	2.00	1.75	1.00	3.00	4.00	5.00
c_i ($/h)	0.00000	0.0000	0.0000	0.0000	0.0000	0.0000

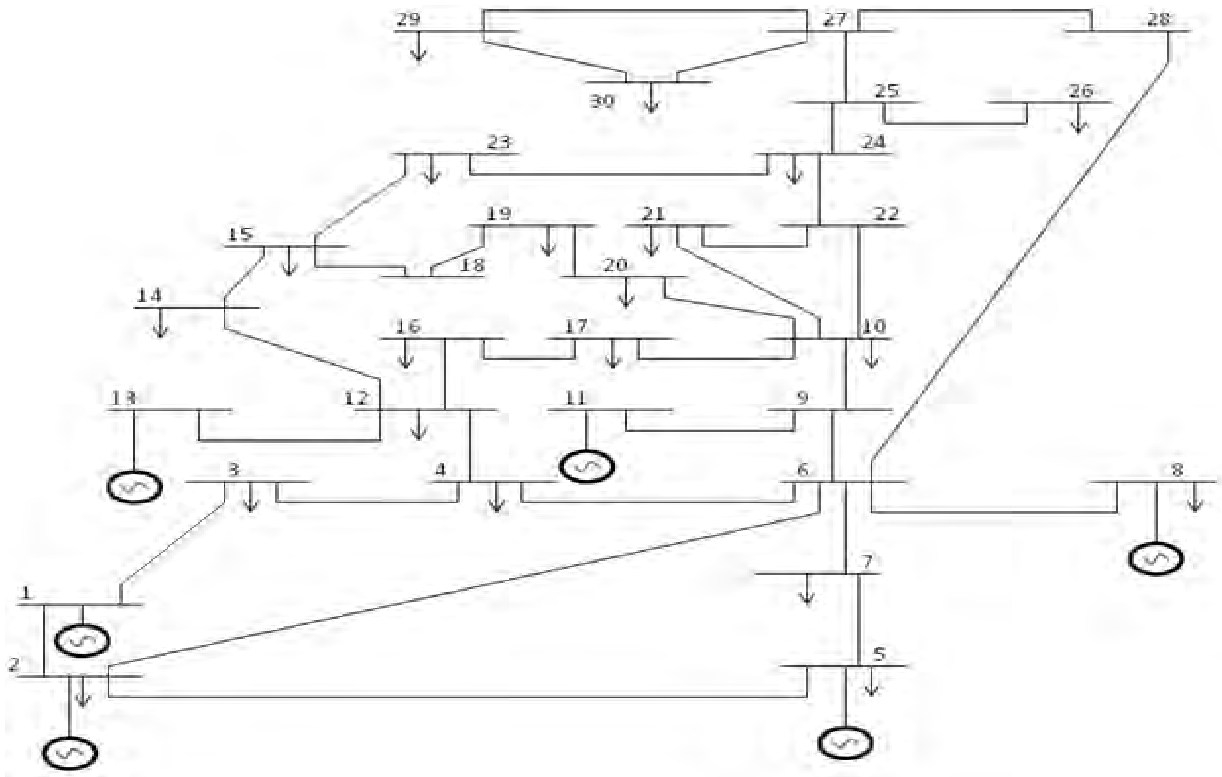

Fig. 5.1 IEEE 30 bus test system's single line diagram

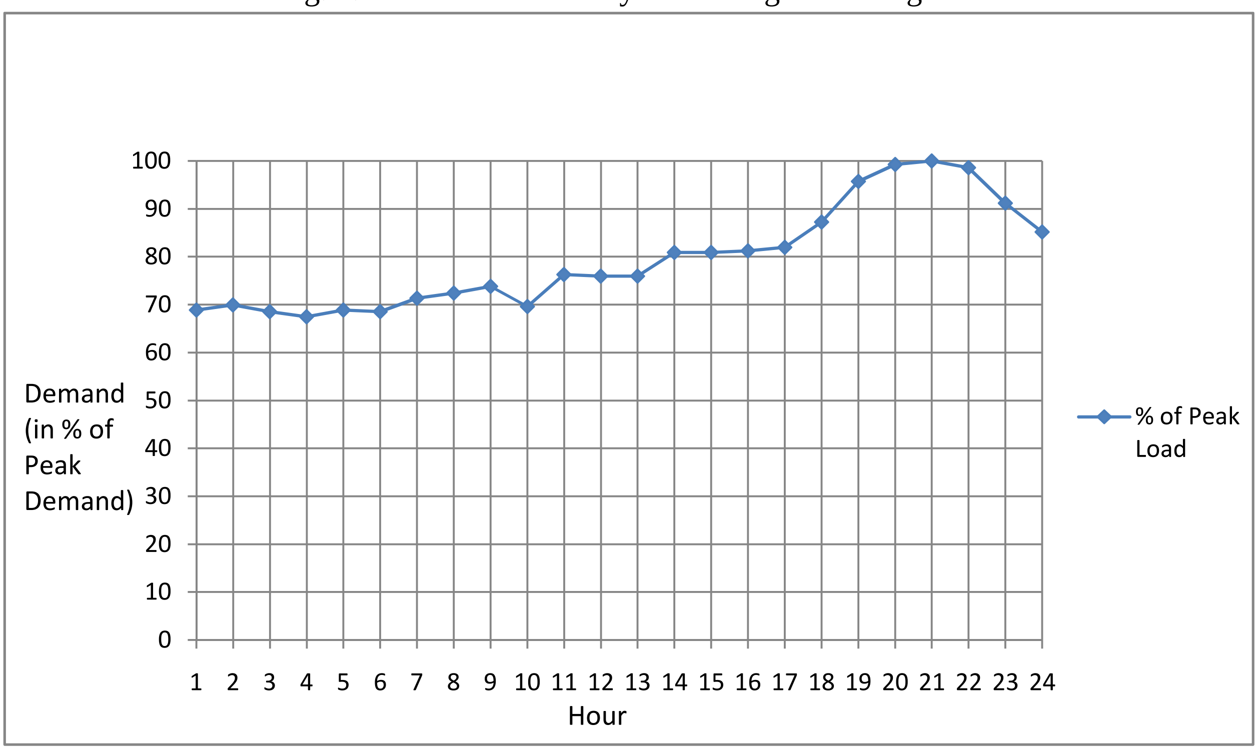

Fig. 5.2 A typical distribution of demand

All the six units in the 30 bus system were considered available. Table 5.2 shows a comparison of the performance of the two methods of scheduling in terms of the number of units selected from among the available units, maximum cost coefficients among the selected units, primal variable (J) for 24 hours, dual variable (q) value, maximum and minimum values for Lagrange multiplier (λ) that have been obtained through extensive simulations varying the loading scenarios and fuel cost coefficients. Transmission loss has been assumed zero (i.e. ideal case) in the proposed scheduling method in the initial case of its comparison with the classical Lagrange so that only the effects of including voltage constraint in the proposed method can be observed. The classical Lagrange method can consider neither voltage constraints nor transmission loss at the scheduling stage. In latter simulations transmission loss has also been considered in the proposed method of scheduling and the impacts compared with that of its own scheduling done without consideration of transmission loss.

Both the scheduling methods took on the average 3 to 4 iterations to converge under various scenarios in the 30-bus system. However, in general compared to the classical Lagrange method the proposed method selected more number of units and some of the selected units were with higher unit energy cost coefficient (b value) depending upon the loading scenario specially for higher loads. This is quite expected as the proposed method is sensitive to individual location of loads and bus voltages and attempts to satisfy the constraint that voltage magnitudes at all the buses be close to 1.0 per unit (p.u.). In general the cost (J) incurred by the proposed method was higher compared to that by the classical Lagrange scheduling which does not consider voltage magnitudes at buses. This is because constrained optimization usually incurs more cost than an unconstrained or less constrained optimization. But unconstrained generation cost optimization results are not realistic and when implemented those indeed increases the cost in real sense due to low voltage and higher losses.

Table 5.3 shows just as a representative case the details of the hour wise unit scheduling by both the methods for the 3rd loading scenario and a set of ‘b’ parameters (energy price coefficients) respectively 2.0, 1.75, 1.00, 4.00, 5.00, 6.00 $/MWh.

Table 5.2 Comparison of the proposed method (P) with the classical Lagrange method (C) under various loading and fuel cost scenarios in IEEE 30 bus system

Simulation set No.	24 hours' forecasted loading scenario	Available 6 units' respective energy price coefficient: b in \$/MWh [a and c coefficients as in Table 5.1]		Maximum No. of units and maximum value of b selected in any hour out of 24 hours	Primal value over 24 hours :J (\$)	Dual value over 24 hours: q (\$)	Duality gap |(J-q)/q| on convergence	Minimum and maximum values of λ (\$/MW/h) in 24 hours
1.	Minimum :191 MW	2.0,1.75,1.00,3.00,4.00,5.00	P	5, 4.00	14696	14449	0.017	2.96, 3.28
			C	4, 3.00	15919	15037	0.059	3.42, 4.13
	Maximum : 283 MW	2.0,1.75,1.00,4.00,5.00,6.00	P	5, 5.00	14513	14336	0.012	3.07, 3.57
			C	3, 2.00	14038	13439	0.045	3.56, 4.06
		2.0,1.75,1.00,6.00,6.00,6.00	P	5, 6.00	14824	14185	0.045	3.28, 3.78
			C	3, 2.00	14039	13439	0.045	3.56, 4.08
2.	Minimum :210 MW	2.0,1.75,1.00,3.00,4.00,5.00	P	6, 5.00	16765	16224	0.033	3.07, 3.37
			C	4, 3.00	14041	13520	0.039	3.28, 3.93
	Maximum : 311 MW	2.0,1.75,1.00,4.00,5.00,6.00	P	5, 5.00	16625	16370	0.016	3.18, 3.77
			C	4, 4.00	16211	15409	0.052	3.49, 4.24
		2.0,1.75,1.00,6.00,6.00,6.00	P	6, 6.00	17294	16454	0.051	3.44, 3.98
			C	3, 2.00	16333	15511	0.053	3.4, 4.45
3.	Minimum :229 MW	2.0,1.75,1.00,3.00,4.00,5.00	P	6, 5.00	20622	19735	0.045	3.25, 3.46
			C	4, 3.00	17846	16848	0.059	3.73, 4.14
	Maximum : 340 MW	2.0,1.75,1.00,4.00,5.00,6.00	P	6, 6.00	21532	20327	0.059	3.45, 3.80
			C	4, 4.00	17968	17451	0.030	3.73, 4.27
		2.0,1.75,1.00,6.00,6.00,6.00	P	6, 6.00	20540	19790	0.038	3.56, 3.94
			C	3, 2.0	18130	17460	0.038	3.73, 4.27
4.	Minimum	2.0,1.75,1.00,3.00,	P	6, 5.00	21807	21342	0.022	3.34, 3.63

	:248 MW	4.00, 5.00	C	4, 3.00	19368	18915	0.024	3.96, 4.24
	Maximum : 368 MW	2.0,1.75,1.00,4.00,5.00,6.00	P	6, 6.00	23601	22481	0.050	3.58, 3.89
			C	4, 4.00	19579	19630	0.003	3.96, 4.59
		2.0,1.75,1.00,6.00,6.00,6.00	P	6, 6.00	24827	23469	0.058	3.87, 4.41
			C	3, 2.00	20207	19668	0.027	3.96, 4.59

Table 5.3 Units scheduled by the proposed and the classical Lagrange methods for 24 hours in IEEE 30 bus system for a loading case (Scenario 3 in Table 5.2)

hour	Total load (MW)		Units scheduled (U_i=1: ON; 0: OFF) by proposed method							Units scheduled (U_i= 1: ON; 0: OFF) by classical Lagrange method					
		units	1	2	3	4	5	6		1	2	3	4	5	6
		b ($/MWh)	2.0	1.75	1.0	4.0	5.0	6.0	b	2.0	1.75	1.0	4.0	5.0	6.0
1	234		1	1	1	1	1	0		1	1	1	0	0	0
2	238		1	1	1	1	1	0		1	1	1	0	0	0
3	233		1	1	1	1	1	0		1	1	1	0	0	0
4	229		1	1	1	1	1	0		1	1	1	0	0	0
5	234		1	1	1	1	1	0		1	1	1	0	0	0
6	233		1	1	1	1	1	0		1	1	1	0	0	0
7	242		1	1	1	1	1	0		1	1	1	0	0	0
8	246		1	1	1	1	1	0		1	1	1	0	0	0
9	251		1	1	1	1	1	0		1	1	1	0	0	0
10	236		1	1	1	1	1	0		1	1	1	0	0	0
11	259		1	1	1	1	1	1		1	1	1	0	0	0
12	258		1	1	1	1	1	0		1	1	1	0	0	0
13	258		1	1	1	1	1	0		1	1	1	0	0	0
14	275		1	1	1	1	1	1		1	1	1	0	0	0
15	275		1	1	1	1	1	1		1	1	1	0	0	0

16	276	1	1	1	1	1	1		1	1	1	0	0	0
17	278	1	1	1	1	1	1		1	1	1	0	0	0
18	296	1	1	1	1	1	1		1	1	1	1	0	0
19	325	1	1	1	1	1	1		1	1	1	1	0	0
20	337	1	1	1	1	1	1		1	1	1	1	0	0
21	340	1	1	1	1	1	1		1	1	1	1	0	0
22	335	1	1	1	1	1	1		1	1	1	1	0	0
23	310	1	1	1	1	1	1		1	1	1	1	0	0
24	289	1	1	1	1	1	1		1	1	1	1	0	0

Tables 5.4 and 5.5 compare the impact of the scheduling done by both the methods respectively for an off-peak hour (11 am) and a peak hour (9 pm) under two loading and cost scenarios mentioned in Table 5.2. These impacts were evaluated by running an OPF using the respective units scheduled i.e. U_i^t values by the two methods for t=11 and t=21. Notably OPF needs a load flow network model and the constraints. Same model and same set of constraints were used for running the OPF to evaluate the two methods of scheduling. It is noteworthy that OPF computes the transmission loss also while it dispatches the scheduled units. It is observed that in general the OPF run using the units scheduled by the proposed method has shown better convergence, improved voltages and less transmission loss.

Table 5.4 OPF performance for <u>an off- peak hour</u> in IEEE 30 bus system in dispatching the units scheduled by the proposed method and the classical Lagrange method for two representative loading cases

Loading pattern and cost coefficients (b) of the units		Based on units scheduling	
Case 1	**OPF performance criteria:**	by classical method: units 1,2,3,4	by proposed method: units 1,2,3,4,5
Minimum: 210MW Maximum: 311 MW b1=2.0,b2=1.75,b3=1.0, b4=3.0,b5=4.0,b6=5.0 [a and c coefficients as in Table 5.1]	Convergence of OPF and CPU time needed	Converged in 0.11s	Converged in 0.11s
	Cost Function value given by OPF ($/hr.)	639.78	648.02
	Maximum bus voltage magnitude	1.06	1.06
	Minimum bus voltage magnitude	0.941	0.951
	Transmission Loss(MW) calculated by OPF	7.58	7.05
	No. of units that exceed respective reactive power limits	0	0
Case 2			
Minimum: 229MW Maximum: 340MW b1=2.0,b2=1.75,b3=1.0, b4=4.0,b5=5.0,b6=6.0 [a and c coefficients as in Table 5.1]	**OPF performance criteria:**	Units scheduled by classical method: 1,2,3	Units scheduled by proposed method: 1,2,3,4,5,6
	Convergence of OPF and CPU time needed	Non convergence	Converged in 0.11s
	Cost Function value given by OPF ($/hr.)	-	780.01
	Maximum bus voltage magnitude	-	1.06
	Minimum bus voltage magnitude	-	0.947
	Transmission Loss(MW) calculated by OPF	-	8.75
	No. of units that exceed respective reactive power limits	-	0

Table 5.5 OPF performance for <u>a peak hour</u> in IEEE 30 bus system in dispatching the units scheduled by the proposed method and the classical Lagrange method for two representative loading cases

Loading pattern and cost coefficients (b) of the units		Based on units scheduling	
Case 1	**OPF performance criteria:**	by classical method: units 1,2,3,4	by proposed method: units 1,2,3,4,5
Minimum: 210MW Maximum: 311 MW b1=2.0,b2=1.75,b3=1.0, b4=3.0,b5=4.0,b6=5.0 [a and c coefficients as in Table 5.1]	Convergence of OPF and CPU time needed	Converged in 0.25s	Converged in 0.30s
	Cost Function value given by OPF ($/hr.)	918.19	916.17
	Maximum bus voltage magnitude	1.06	1.06
	Minimum bus voltage magnitude	0.94	0.953
	Transmission Loss(MW) calculated by OPF	12.77	12.07
	No. of units that exceed respective reactive power limits	0	0
Case 2			
Minimum: 229MW Maximum: 340MW b1=2.0,b2=1.75,b3=1.0, b4=4.0,b5=5.0,b6=6.0 [a and c coefficients as in Table 5.1]	**OPF performance criteria:**	Units scheduled by classical method: 1,2,3,4	Units scheduled by proposed method: 1,2,3,4,5,6
	Convergence of OPF and CPU time needed	Non convergence	Converged in 0.25s
	Cost Function value given by OPF ($/hr.)	-	1104.97
	Maximum bus voltage magnitude	-	1.06
	Minimum bus voltage magnitude	-	0.953
	Transmission Loss(MW) calculated by OPF	-	13.17
	No. of units that exceed respective reactive power limits	-	0

The sample results of OPF using units scheduled by both the methods for the peak hour under loading scenario-1 of Table 5.5 are given in Sec A.4 of Appendix A.

Figs. 5.3 and 5.4 compare the voltage profiles obtained by the OPF run respectively at the off peak hour (11 am) and the peak hour (9 pm) for the loading scenario (minimum demand: 210 MW and maximum demand: 311 MW over 24 hours, b1=2.0, b2=1.75, b3=1.0, b4=3.0, b5=4.0, b6=5.0 as mentioned in Table 5.4 and 5.5). In general the voltage profile obtained using units scheduled by the proposed method was better than that using the units scheduled by the classical Lagrange method.

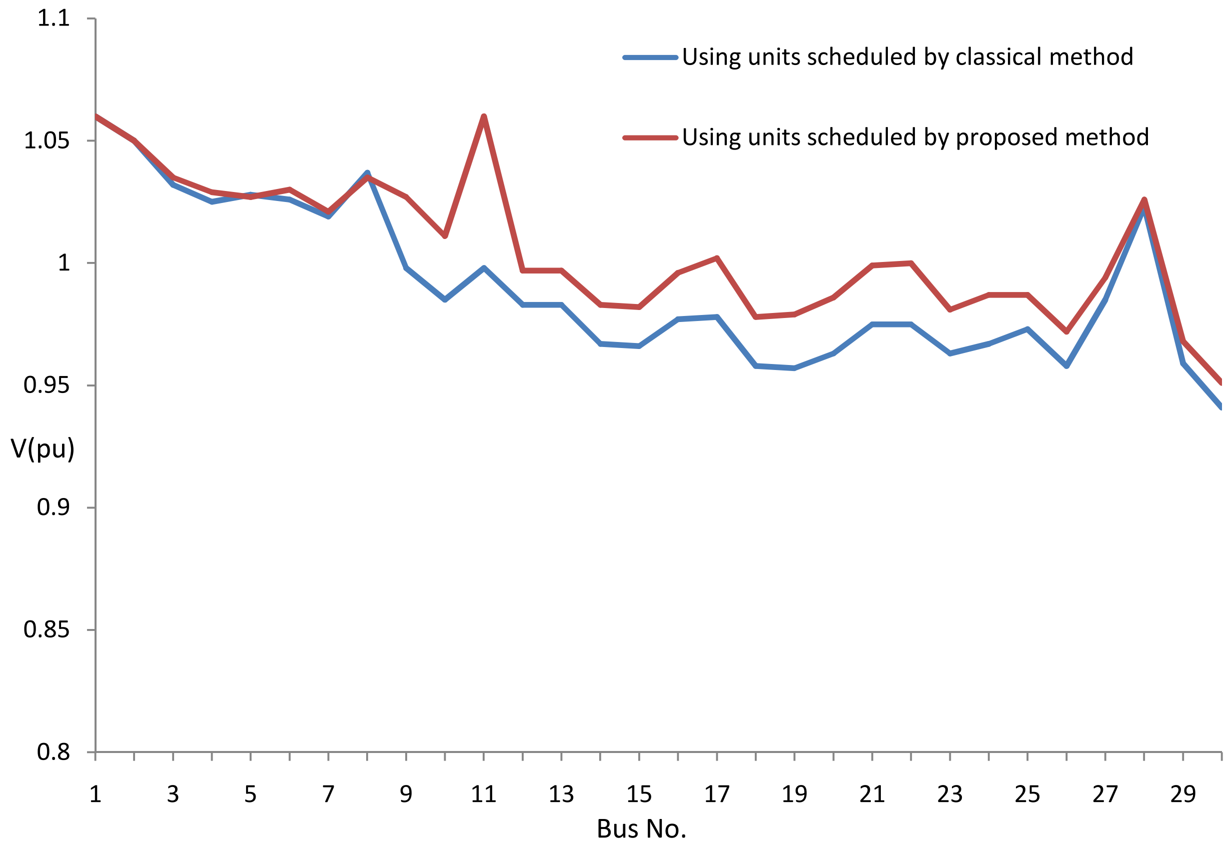

Fig. 5.3 Voltage profile by OPF run using units scheduled by two methods **at an off peak hour** in 30 bus test system (loading scenario 1 of Table 5.4)

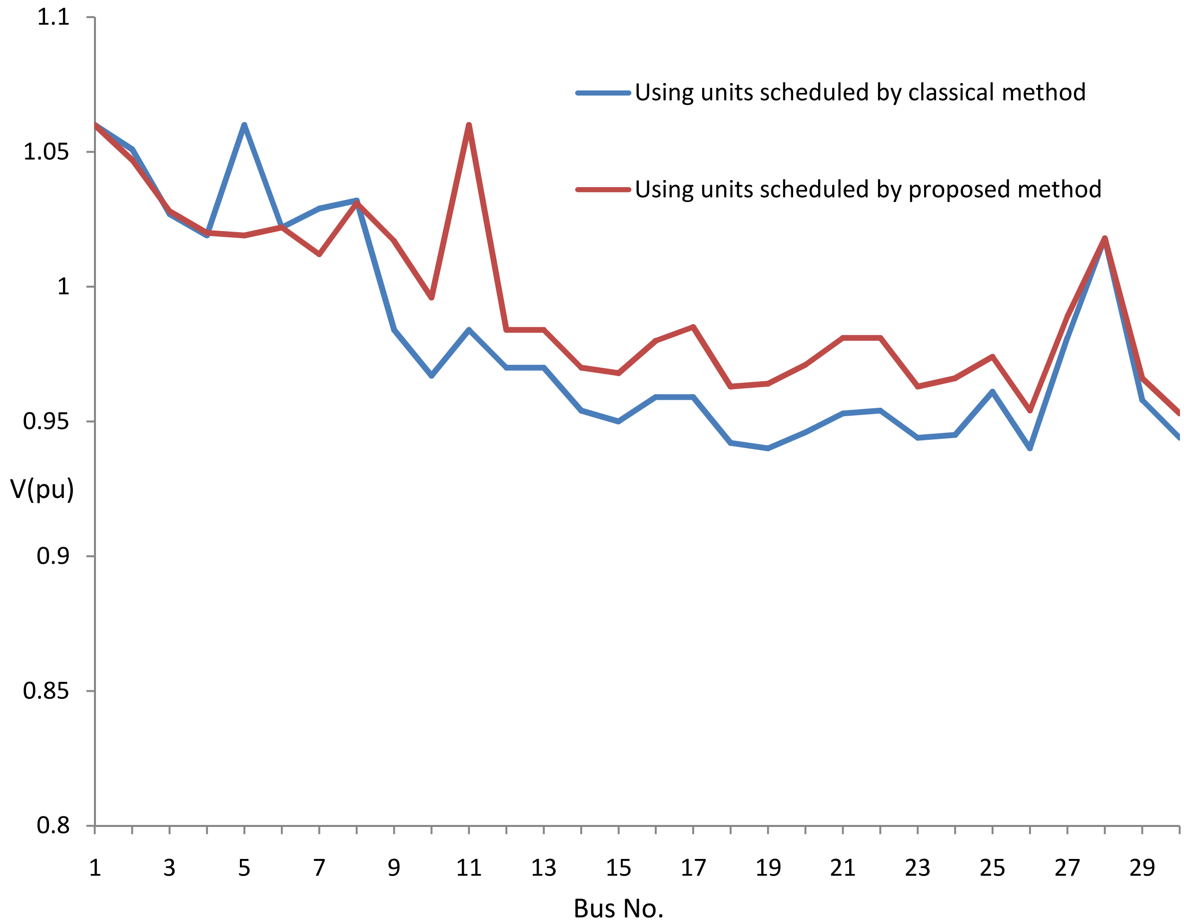

Fig. 5.4 Voltage profile by OPF run using units scheduled by two methods **at a peak hour** in 30 bus test system (loading scenario 1 of Table 5.5)

As mentioned in the 4th paragraph of this section, the impacts of scheduling done by the proposed method considering no transmission loss will be compared against the impacts of scheduling done by the same but considering transmission loss. Tables 5.6 and 5.7 show the impacts respectively for an off-peak hour and a peak hour obtained running an OPF using the units scheduled by the proposed method under the same loading scenario without and with consideration of 2% transmission loss (p=0.02) in the way shown in the model developed in Sec 4.2. In general consideration of loss at scheduling stage by the proposed method would select more appropriate units compared to its own scheduling without loss consideration so that the results of an OPF for an hour based on the former scheduling (with loss consideration) represent more optimum cost, loss (close to assumed 2%) and bus voltage magnitudes than that based on the latter scheduling (without loss consideration).

Table 5.6 OPF performance for an off-peak hour in IEEE 30 bus system in dispatching the units scheduled by the proposed method without and with consideration of transmission loss

Loading pattern and cost coefficients (b) of the units		Based on units scheduling by the proposed method	
	OPF performance criteria:	without consideration of transmission loss at scheduling stage: units scheduled 1,2,3,4,5,6	with consideration of transmission loss at scheduling stage: units scheduled 1,2,3,4
Minimum: 229MW Maximum: 340MW b1=2.0,b2=1.75,b3=1.0, b4=4.0,b5=5.0,b6=6.0 [a and c coefficients as in Table 5.1]	Convergence of OPF and CPU time needed	Converged in 0.11s	Converged in 0.11s
	Cost Function value given by OPF ($/hr.)	780.01	773.63
	Maximum bus voltage magnitude	1.06	1.06
	Minimum bus voltage magnitude	0.947	0.940
	Transmission Loss(MW) calculated by OPF	8.75	6.98
	No. of units that exceed respective reactive power limits	0	0

Table 5.7 OPF performance for a peak hour in IEEE 30 bus system in dispatching the units scheduled by the proposed method without and with consideration of transmission loss

Loading pattern and cost coefficients (b) of the units		Based on units scheduling by the proposed method	
Minimum: 229MW Maximum: 340MW b1=2.0,b2=1.75,b3=1.0, b4=4.0,b5=5.0,b6=6.0 [a and c coefficients as in Table 5.1]	**OPF performance criteria:**	Without consideration of transmission loss at scheduling stage: units scheduled 1,2,3,4,5,6	with consideration of transmission loss at scheduling stage: units scheduled 1,2,3,4,5
	Convergence of OPF and CPU time needed	Converged in 0.25s	Converged in 0.11s
	Cost Function value given by OPF ($/hr.)	1104.97	1085.13
	Maximum bus voltage magnitude	1.06	1.06
	Minimum bus voltage magnitude	0.953	0.94
	Transmission Loss(MW) calculated by OPF	13.17	13.59
	No. of units that exceed respective reactive power limits	0	0

5.3.1 Comparison with Literature Result

The overall impact of the scheduling by the proposed method has also been compared in terms of the objective function cost with that in literature [61] available only for a peak hour in IEEE 30-bus system.

In [61] the load profile for other hours was not given and the fuel cost coefficients of the generators for the IEEE 30-bus system were not mentioned. It was assumed that all the six units are scheduled in the peak hour against a total load of 283 MW though the method of scheduling was unknown. Instead of using the OPF, a multi-objective PSO based dispatching algorithm was used to dispatch all the six units for this peak load. The objective function value was reported to be 938.906 $/hr. Other indicators such as loss and bus voltages were not available for a comparison.

On the contrary the proposed method scheduled 5 units excluding the unit at bus 13 for the same peak hour load. Then the 5 units were dispatched i.e. load allocated among them using the OPF. This resulted in a fuel cost of 808.74 $/hr. The loss was 9.53 MW and the minimum bus voltage was 0.967 p.u.

Notably, the classical Lagrange method scheduled 4 units excluding those at bus 11 and 13. The resulting fuel cost obtained by running OPF for these is 803.43 $/hr. The loss was 10.43 MW and the minimum bus voltage was 0.952 p.u.

The difference with literature [61] is obviously due to the difference in the objective, number of scheduled units, their loading and cost coefficients. Nevertheless, this comparison has been done just as an additional reference though the mathematical models, parameter requirements and test conditions of the proposed and the literature [61] methods are totally different.

5.4 Application in Bangladesh Power System

Bangladesh Power System (BPS), shown in Fig. 5.5, has a total of 166 buses of which 93 have generation units connected to them. These units have a total maximum generation capacity equal to 8215 MW. The units are of various types such as gas turbine, steam turbine, combined cycle, gas engine and oil engine. Fuel wise these are gas, coal, oil (diesel/heavy fuel oil) and hydro operated. The buses are at 230 kV and 132 kV levels being connected by 188 Nos. of transmission lines and 14 Nos. of 230/132 kV tie-transformers. The network data in per unit of 100 MVA are given in Sec. B.1 in Appendix B. The range of the fuel cost coefficients (‘b’ component in $/MWh) and sizes (maximum MW) of the generation units are given in Table 5.8. The details of the generation units’ operational limits and all the coefficients of quadratic fuel cost characteristics are given in Table B.1.4 in Sec. B.1.

The total system load and bus wise load (MW) data for 24 hours presented in Sec. B.2 in Appendix B correspond to the ‘forecasted’ load curve shown in Fig. 5.6. In fact this load curve represents the actual load data of 26 April 2012 taken from the National Load Despatch Centre (NLDC) of BPS. The day is a typical one representing the summer as well as irrigation loads in BPS. That day the peak load was 4995 MW and it occurred at 9 pm. However, the proposed as well as the classical method both can always be tested using forecasted load curve for any day in any season. The bus wise reactive demands (MVAR) were obtained considering 0.85 lagging power factor at the grid substation buses. The generation units are also considered to be operating at 0.85 lagging power factor.

In a way similar to that for 30 bus system mentioned in Sec. 5.2, the bus impedance matrix [Z]= ([R] +j[X]) of 165x165 order was formed with Bus No. 1 as the reference for use by the developed method. Section B.3 in Appendix B shows the elements of [R] and [X] for selected rows and columns as sample.

Table 5.8 Summary of sizes and fuel cost related data for the 93 generation units of BPS

Fuel	Number of units	Range of b coefficients ($/MWh)	Range of sizes (maximum MW)
Hydro	1 (5 combined as a single unit)	0	2x40 MW+3x50 MW =230 MW
Gas	57	32-56	11 MW- 450 MW
Coal	2	59	125 MW each
Oil	33	109-267	20 MW - 115 MW

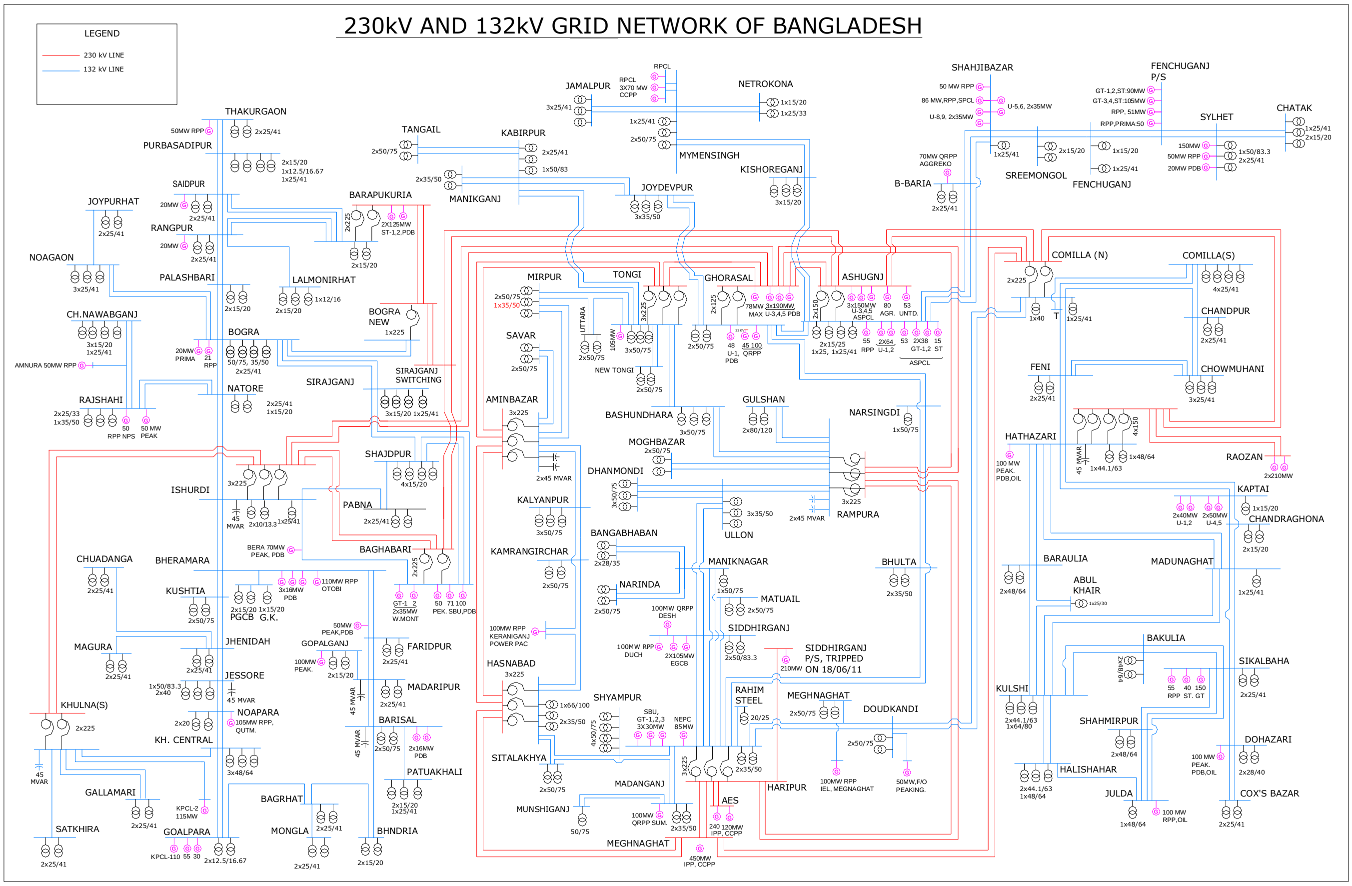

Fig. 5.5 Single line diagram of 166-bus Bangladesh Power System (BPS) as of the year 2012

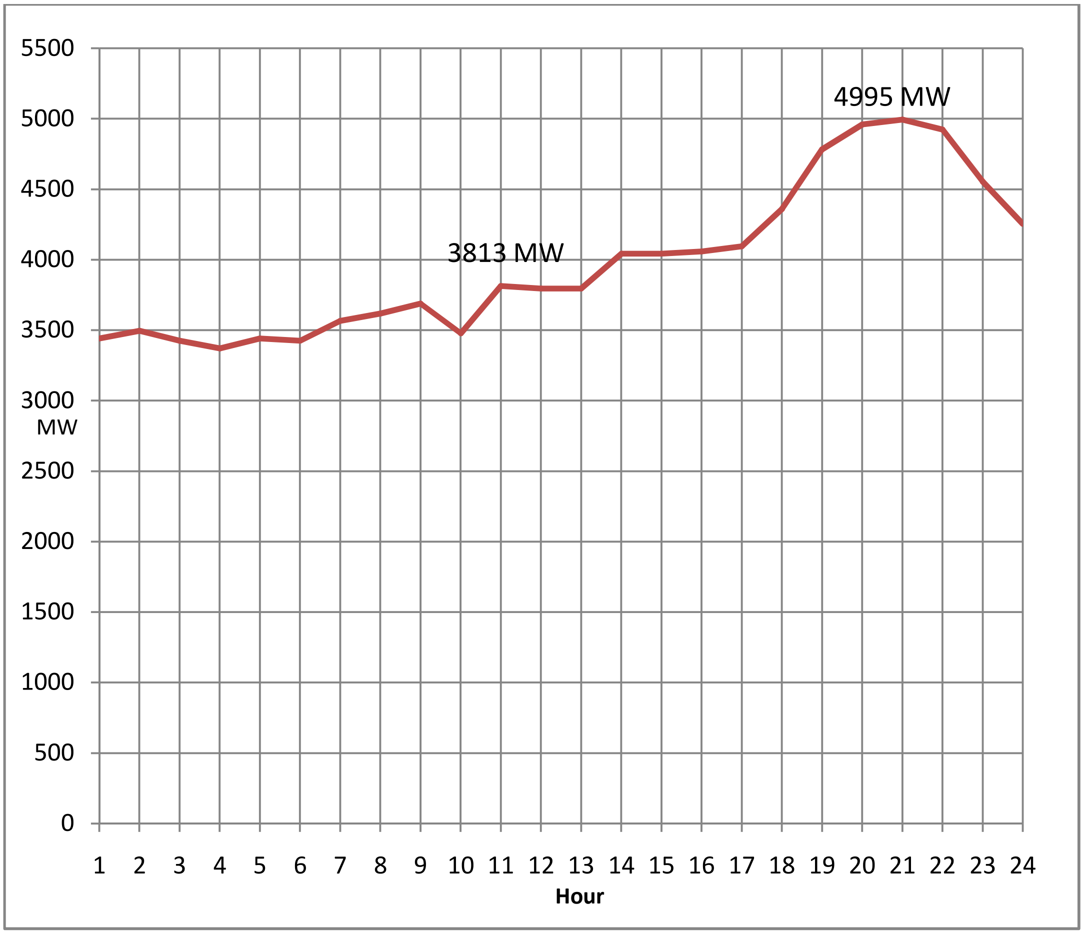

Fig. 5.6 ‘Forecasted’ load curve for use in the test of the proposed method for generation scheduling in BPS and comparison against the classical Lagrange method

All the 93 units in the BPS system were considered available. Table 5.9 shows a comparison of the performance of the two methods of scheduling in terms of the number of units selected from among the available units, primal variable (J) for 24 hours, dual variable (q) value, maximum and minimum values for Lagrange multiplier (λ). Both methods have been applied for two loading scenarios (one as in Fig. 5.6 and the other one is with 10% increase in the load every hour) with the same set of fuel cost coefficients given in Table 5.8 and Sec. B.1. Notably a few oil based generation units have also been selected by the proposed method specially in peak hours in order to maintain bus voltages at satisfactory level. Other results have similar significance as those obtained in IEEE 30 bus test system. The comparison was made without considering transmission loss at the scheduling stage by the proposed method so that only the effects of including voltage constraint in the proposed method can be observed. The classical Lagrange is unable to consider voltage as well as loss at the scheduling stage.

The details of units scheduled by both methods for 24 hours under loading scenario-2 are shown in Sec. B.4 in Appendix B. The details of scheduling by both the methods only for an off-peak hour (11 am) and a peak hour (9 pm) under the two loading scenarios have also been focused in Sec. B.5.

The impacts of the scheduling by both methods have been further evaluated by running an OPF using the units scheduled respectively for the off-peak hour (11 am) and the peak hour (9 pm) under two loading scenarios. Table 5.10 compares the impacts. It is observed that in general i.e. in most of the hours, the OPF run using the units scheduled by the proposed method has shown better convergence, improved voltages and less transmission loss.

Table 5.9 Comparison of proposed method and classical Lagrange methods of scheduling applied in BPS under two loading scenarios but same cost coefficients

24 hours' forecasted loading scenario	Criteria	Classical Lagrange	Proposed method
1.Minimum : 3371 MW Maximum: 4995 MW	λ max in 24 hours ($/MW/h)	63.03	41.14
	λ min in 24 hours ($/MW/h)	51.36	21.68
	No. of iterations	7	4
	No. of gen. with U=1 i.e. ON status (at a peak hour i.e. 21 hour)	60 including 1 hydro, 57 gas and 2 coal based units	63 including 1 hydro, 57 gas, 2 coal and 3 oil based units
	Dual value over 24 hours: q ($)	4,112,757	5,114,020
	Primal value over 24 hours :J ($)	4,312,292	5,365,238
2.Minimum : 3708 MW Maximum: 5495 MW	λ max in 24 hours ($/MW/h)	68.28	44.20
	λ min in 24 hours ($/MW/h)	60.74	22.93
	No. of iterations	4	5
	No. of gen. with U=1 i.e. ON status (at a peak hour i.e. 21 hour)	60 including 1 hydro, 57 gas and 2 coal based units	69 including 1 hydro, 57 gas, 2 coal and 9 oil based units
	Dual value over 24 hours: q ($)	4,516,763	5,563,360
	Primal value over 24 hours :J ($)	4,739,047	5,661,669

Table 5.10 Comparison of results from OPF using the units scheduled by the proposed and classical Lagrange methods

Loading pattern		Peak hour		Off-peak hour	
No. 1 Minimum: 3371 MW Maximum: 4995 MW [cost coefficients as in Table 5.8]		**OPF run using units scheduled by:**			
	OPF performance criteria	**Classical Lagrange**	**Proposed method**	**Classical Lagrange**	**Proposed method**
	Convergence of OPF and CPU time needed	Converged in 0.22s	Converged in 1.00s	Converged in 0.20s	Converged in 0.19s
	Objective Function value ($/hr.)	237,271.95	237,669.32	167,497.9	168,231.8
	Maximum bus voltage magnitude	1.05	1.05	1.05	1.05
	Minimum bus voltage magnitude	0.887	0.966	0.897	0.906
	Transmission Loss(MW) calculated by OPF	143.25	137.89	100.94	94.9
	No. of units that exceed respective reactive power limits	0	0	0	0
		Peak hour		**Off-peak hour**	
No. 2 Minimum: 3708 MW Maximum: 5495 MW [cost coefficients as in Table 5.8]		**OPF run using units scheduled by:**			
	OPF performance criteria	**Classical Lagrange**	**Proposed method**	**Classical Lagrange**	**Proposed method**
	Convergence of OPF and CPU time needed	Non convergence	Converged in 0.23s	Converged in 3.22s	Converged in 0.52s
	Objective Function value ($/hr.)	-	275,769.7	188,859.2	188,892.3
	Maximum bus voltage magnitude	-	1.05	1.05	1.05
	Minimum bus voltage magnitude	-	0.933	0.922	0.922
	Transmission Loss(MW) calculated by OPF	-	171.88	107.27	108.37
	No. of units that exceed respective reactive power limits	-	0	0	0

The sample results of OPF using units scheduled by both the methods for the peak hour under loading scenario-1 are given in Sec B.6 of Appendix B.

It should be noted in Table 5.10 under loading scenario 2, that the OPF did not converge in a peak hour while took much higher time to converge in an off-peak hour when it was run using the units scheduled by classical Lagrange. In fact higher convergence time implies almost non-convergence and an OPF program in such cases yields non-realistic or insignificant results. This is the reason that in the off-peak hour the OPF solution using generators scheduled by classical Lagrange showed same minimum voltage and slightly less transmission loss than that shown by the OPF solution using the generators scheduled by proposed method. However, the total number of buses with voltage magnitudes above minimum voltage was higher when OPF used proposed method's schedule.

Figs. 5.7 and 5.8 compare as a representative case the voltage profiles obtained from OPF runs (based on scheduling by two methods) respectively for the off peak hour (11 am) and the peak hour (9 pm) under the loading scenario-1 as mentioned in Table 5.9 and Table 5.10. In general the voltage profile obtained from OPF using units scheduled by the proposed method is better (i.e. more number of buses with voltage magnitudes significantly above the minimum) than that using the units scheduled by the classical Lagrange method.

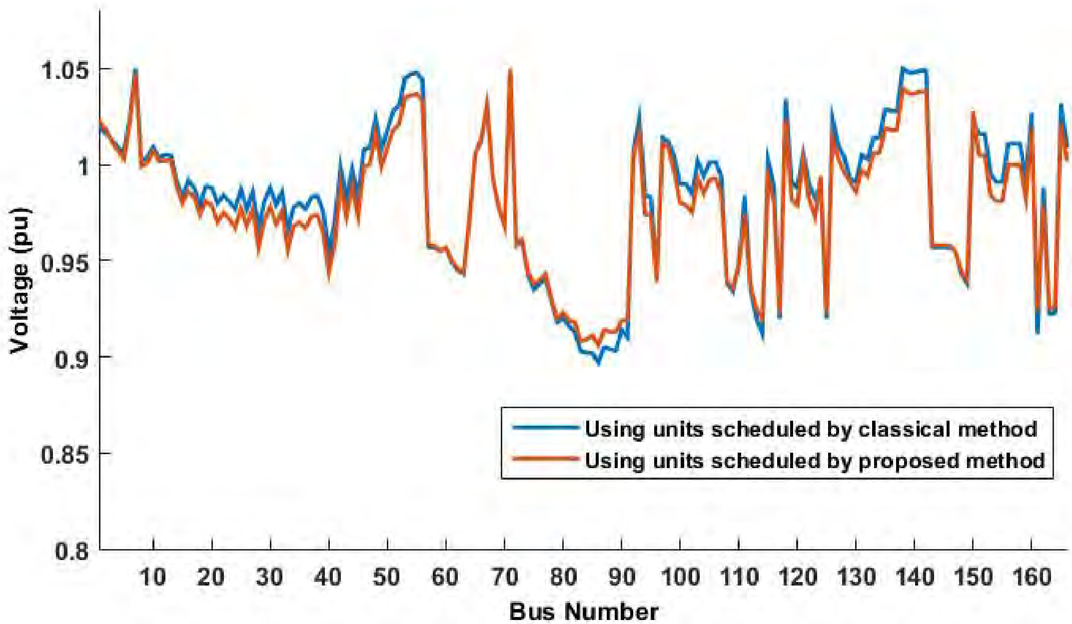

Fig. 5.7 Voltage profile by OPF run using units scheduled by two methods **at an off-peak hour** in BPS (loading scenario 1 of Tables 5.9 and 5.10)

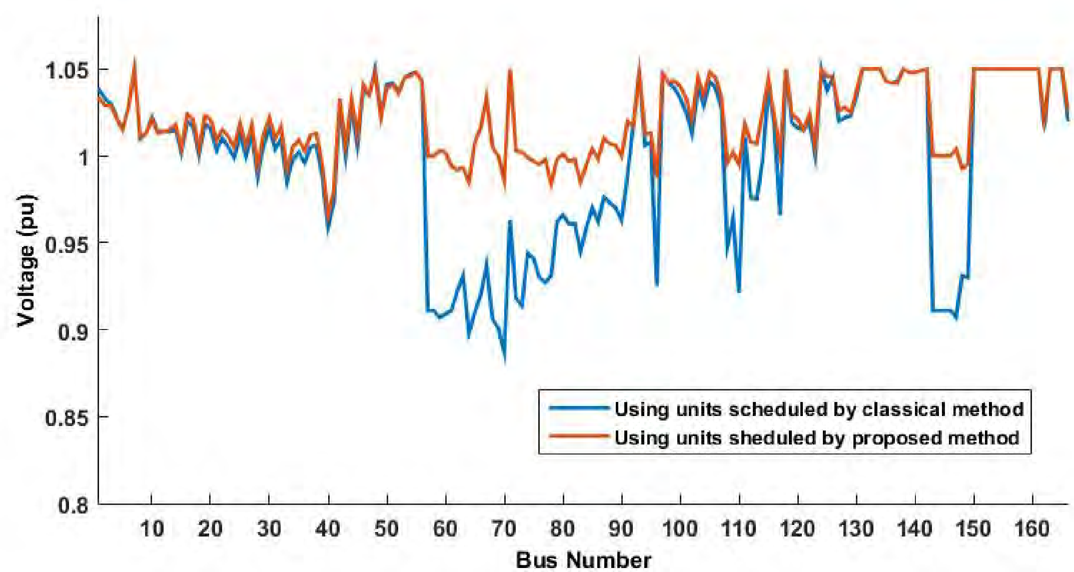

Fig. 5.8 Voltage profile by OPF run using units scheduled by two methods **at a peak hour** in BPS (loading scenario 1 of Tables 5.9 and 5.10)

5.5 Conclusion

For validation, evaluation of the performance and the potentials for general applicability in any system, the proposed method of generation scheduling has been extensively tested and compared against the classical Lagrange method (i) in IEEE 30 bus standard system with 6 units under various forecasted loading scenarios and quadratic cost characteristic's coefficients and (ii) in a real life system (Bangladesh Power System) with 166 buses and 93 generation units under two forecasted loading scenarios but same set of cost coefficients.

Since the proposed method considers bus voltages at the scheduling stage and it has to maintain an acceptable voltage profile, it schedules besides cheaper units also the relatively expensive units near the load centres. Naturally the fuel cost incurred in the proposed method over 24 hours is in general a bit higher (as expected) than that in the classical method which cannot consider voltage and line loss at the scheduling stage. The proposed method when considers transmission loss at the scheduling stage shows in general a better performance relative to itself when no loss is considered at the scheduling stage.

The actual impacts of both the scheduling methods on system operation have been evaluated by running an optimal power flow (OPF). Notably the OPF allocates the hourly load, satisfying all the constraints, among the generation units which have ON status in an hour as decided by a scheduling method. Under various loading scenarios and in most of the hours the performance of the OPF using the generation units scheduled by the proposed method was observed to be better (in terms of convergence, number of buses with voltages significantly above minimum voltage, and line loss) than the OPF using the generation units scheduled by the classical Lagrange method.

Chapter 6 Conclusion

This chapter highlights the main achievements of the present research and suggests some possible extensions.

6.1 General Conclusion

Power system experiences variable demand in its daily operational cycle that requires appropriate scheduling of the generation units and allocation of the forecasted loads among them in every hour such that the total production cost (over 24 hours) becomes the minimum subject to satisfying the operational constraints. Usually the major coupling constraint considered in selecting generation units by the classical Lagrange and other existing scheduling methods is the load balance equation i.e. sum of the power outputs of the units selected in an hour should equal the corresponding demand neglecting loss. Notably the separable constraints such as minimum up or down time, maximum and minimum generation capacity, ramp rate and start up cost etc. that relate to individual units are easy to be considered in these methods. On the other hand the important coupled constraints (e.g. bus voltages and transmission loss which are functions of outputs of all the units to be scheduled) are not considered in the existing methods. Those are left for consideration at the dispatching stage after the scheduling is done.

This research has shown that if the bus voltage constraints and the transmission loss are not considered during the scheduling stage the generation cost may be less but such a scheduling will be unable to overcome the low voltage problem and higher transmission loss. For this a new scheduling method has been proposed with a modified Lagrange function that schedules the units based on their capability to influence the system bus voltages and transmission loss besides their fuel costs. As a result the units with relatively higher fuel cost but located near the load centres in a system may also be selected leading to an optimum generation cost with improved voltage and reduced loss over the total time period. Notably the separable constraints can always be considered in the proposed method in the same way as the classical methods do. Other constraints related to transmission network can be considered in the OPF to be run after scheduling is done.

The method has been applied in the standard IEEE 30-bus test system and a practical 166-bus power system i.e. Bangladesh Power System. The status (ON/OFF) of the units obtained by the method for some of the typical peak and off peak hours was given as input to an OPF to be run for the corresponding hours to obtain load allocation, system voltage profile and losses in the respective hours. The performance was compared with that of a classical Lagrange based scheduling method being applied in the same way on the same systems for identical scenarios on loading and individual units' fuel cost parameters. It was observed that in general the proposed method excels the classical one from a simultaneous consideration of fuel cost for 24 hours, system wide voltage and transmission losses.

6.2 Suggestions for Further Research

Some of the areas worthy of further investigation are suggested below.

i. Besides the load and voltage constraints in the proposed generation scheduling method, use of another coupling constraint is expected to further enhance its performance and versatility. This is the power reserve constraint i.e. the load plus spinning reserve in each hour of the total period should be equal to or less than the sum of the maximum generation capacities of the units to be selected for that hour. This will ensure a requisite reserve distributed among the units scheduled for each hour so that AGC can work on these units to ride through steady state changes in system load and frequency. So incorporating reserve margin constraint in the proposed method can be an interesting investigation.

ii. Use of Mixed Integer Linear Programming (MILP) in which all the constraints and every components of the Lagrange function are linearized or piecewise linearized while control variables are discrete (e.g. unit status) and continuous numbers (e.g. unit output power), can reduce the computational time and improve the convergence of the proposed method like any other MILP based Lagrange method when it is applied in large systems. However, solution inaccuracy due to linearization may be a problem. So developing an MILP version of the proposed method that would not compromise the accuracy also deserves investigation.

iii. Usually the thermal generation unit fuel cost characteristics curve is considered by most of the scheduling methods as a convex and smooth quadratic function of the unit's power output. However, for certain steam turbines with multiple valves such a curve is usually non-convex with ripples that can be best represented by adding an appropriate sinusoidal term with the quadratic cost function. But handling such a curve through differentiation is difficult. So linearizaion of the non-convex curve and incorporating this in developing an MILP version for the proposed method as mentioned in (ii) above is worth interest.

iv. Application of the proposed methodology by an ISO in an electricity market oriented power system for scheduling (selecting) the units submitting on-line bids for multiple hours together can be an interesting research topic. This may reduce the need for acquisition of ancillary services like reactive power or voltage support.

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APPENDIXES

APPENDIX: A
IEEE 30 Bus Test System Related Data

A.1 Network data

Bus data (demands for a peak hour under loading pattern 1)

bus_i	type	Pd MW	Qd MVAR	Gs pu	Bs pu	base kV
1	3	0	0	0	0	132
2	2	21.7	13.45	0	0	132
3	1	2.4	1.49	0	0	132
4	1	7.6	4.71	0	0	132
5	2	94.2	58.4	0	0	132
6	1	0	0	0	0	132
7	1	22.8	14.14	0	0	132
8	2	30	18.6	0	0	132
9	1	0	0	0	0	1
10	1	5.8	3.6	0	19	33
11	2	0	0	0	0	11
12	1	11.2	6.94	0	0	33
13	2	0	0	0	0	11
14	1	6.2	3.84	0	0	33
15	1	8.2	5.08	0	0	33
16	1	3.5	2.17	0	0	33
17	1	9	5.58	0	0	33
18	1	3.2	1.98	0	0	33
19	1	9.5	5.89	0	0	33
20	1	2.2	1.36	0	0	33
21	1	17.5	10.85	0	0	33
22	1	0	0	0	0	33
23	1	3.2	1.98	0	0	33
24	1	8.7	5.39	0	4.3	33
25	1	0	0	0	0	33
26	1	3.5	2.17	0	0	33
27	1	0	0	0	0	33
28	1	0	0	0	0	132
29	1	2.4	1.49	0	0	33
30	1	10.6	6.57	0	0	33

type1: PQ bus
type2: PV bus
type3: Slack bus
Gs: Shunt conductance
Bs: Shunt capacitor susceptance

Generator data

bus	Qmax MVAR	Qmin MVAR	Vg pu	MVA Base	*status (input from scheduling method: U_i^t)	Pmax MW	Pmin MW
1	250	-20	1.01	100	-	200	50
2	100	-20	0	100	-	80	20
5	80	-15	0	100	-	50	15
8	60	-15	0	100	-	35	10
11	50	-10	0	100	-	30	10
13	60	-15	0	100	-	40	12

Branch(line/transformer) data
on 100 MVA base

from bus	to bus	r pu	x pu	b pu	MVA Limit
1	2	0.0192	0.0575	0.0528	130
1	3	0.0452	0.1652	0.0408	130
2	4	0.057	0.1737	0.0368	65
3	4	0.0132	0.0379	0.0084	130
2	5	0.0472	0.1983	0.0418	130
2	6	0.0581	0.1763	0.0374	65
4	6	0.0119	0.0414	0.009	90
5	7	0.046	0.116	0.0204	70
6	7	0.0267	0.082	0.017	130
6	8	0.012	0.042	0.009	32
6	9	0	0.208	0	65
9	11	0	0.208	0	65
9	10	0	0.11	0	65
4	12	0	0.256	0	65
12	13	0	0.14	0	65
12	14	0.1231	0.2559	0	32
12	15	0.0662	0.1304	0	32
12	16	0.0945	0.1987	0	32
14	15	0.221	0.1997	0	16
16	17	0.0524	0.1923	0	16
15	18	0.1073	0.2185	0	16
18	19	0.0639	0.1292	0	32
19	20	0.034	0.068	0	32
10	20	0.0936	0.209	0	32
10	17	0.0324	0.0845	0	32
10	21	0.0348	0.0749	0	32
10	22	0.0727	0.1499	0	32
21	22	0.0116	0.0236	0	32
15	23	0.1	0.202	0	16
22	24	0.115	0.179	0	16
23	24	0.132	0.27	0	16
24	25	0.1885	0.3292	0	16
25	26	0.2544	0.38	0	16
25	27	0.1093	0.2087	0	16
28	27	0	0.396	0	65
27	29	0.2198	0.4153	0	16
27	30	0.3202	0.6027	0	16
29	30	0.2399	0.4533	0	16
8	28	0.0636	0.2	0.0428	32
6	28	0.0169	0.0599	0.013	32

A.2: Total load and bus wise load (MW) data for 24 hours (loading pattern-1 i.e. base case)

BUS HR.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	**Total Load MW**
1	0.0	14.9	1.7	5.2	64.8	0.0	15.7	20.6	0.0	4.0	0.0	7.7	0.0	4.3	5.6	2.4	6.2	2.2	6.5	1.5	12.0	0.0	2.2	6.0	0.0	2.4	0.0	0.0	1.7	7.3	**195**
2	0.0	15.2	1.7	5.3	65.8	0.0	15.9	21.0	0.0	4.1	0.0	7.8	0.0	4.3	5.7	2.4	6.3	2.2	6.6	1.5	12.2	0.0	2.2	6.1	0.0	2.4	0.0	0.0	1.7	7.4	**198**
3	0.0	14.9	1.6	5.2	64.5	0.0	15.6	20.5	0.0	4.0	0.0	7.7	0.0	4.2	5.6	2.4	6.2	2.2	6.5	1.5	12.0	0.0	2.2	6.0	0.0	2.4	0.0	0.0	1.6	7.3	**194**
4	0.0	14.6	1.6	5.1	63.5	0.0	15.4	20.2	0.0	3.9	0.0	7.5	0.0	4.2	5.5	2.4	6.1	2.2	6.4	1.5	11.8	0.0	2.2	5.9	0.0	2.4	0.0	0.0	1.6	7.1	**191**
5	0.0	14.9	1.7	5.2	64.8	0.0	15.7	20.6	0.0	4.0	0.0	7.7	0.0	4.3	5.6	2.4	6.2	2.2	6.5	1.5	12.0	0.0	2.2	6.0	0.0	2.4	0.0	0.0	1.7	7.3	**195**
6	0.0	14.9	1.6	5.2	64.5	0.0	15.6	20.5	0.0	4.0	0.0	7.7	0.0	4.2	5.6	2.4	6.2	2.2	6.5	1.5	12.0	0.0	2.2	6.0	0.0	2.4	0.0	0.0	1.6	7.3	**194**
7	0.0	15.5	1.7	5.4	67.1	0.0	16.3	21.4	0.0	4.1	0.0	8.0	0.0	4.4	5.8	2.5	6.4	2.3	6.8	1.6	12.5	0.0	2.3	6.2	0.0	2.5	0.0	0.0	1.7	7.6	**202**
8	0.0	15.7	1.7	5.5	68.1	0.0	16.5	21.7	0.0	4.2	0.0	8.1	0.0	4.5	5.9	2.5	6.5	2.3	6.9	1.6	12.7	0.0	2.3	6.3	0.0	2.5	0.0	0.0	1.7	7.7	**205**
9	0.0	16.0	1.8	5.6	69.5	0.0	16.8	22.1	0.0	4.3	0.0	8.3	0.0	4.6	6.0	2.6	6.6	2.4	7.0	1.6	12.9	0.0	2.4	6.4	0.0	2.6	0.0	0.0	1.8	7.8	**209**
10	0.0	15.1	1.7	5.3	65.5	0.0	15.8	20.9	0.0	4.0	0.0	7.8	0.0	4.3	5.7	2.4	6.3	2.2	6.6	1.5	12.2	0.0	2.2	6.0	0.0	2.4	0.0	0.0	1.7	7.4	**197**
11	0.0	16.5	1.8	5.8	71.8	0.0	17.4	22.9	0.0	4.4	0.0	8.5	0.0	4.7	6.2	2.7	6.9	2.4	7.2	1.7	13.3	0.0	2.4	6.6	0.0	2.7	0.0	0.0	1.8	8.1	**216**
12	0.0	16.5	1.8	5.8	71.5	0.0	17.3	22.8	0.0	4.4	0.0	8.5	0.0	4.7	6.2	2.7	6.8	2.4	7.2	1.7	13.3	0.0	2.4	6.6	0.0	2.7	0.0	0.0	1.8	8.0	**215**
13	0.0	16.5	1.8	5.8	71.5	0.0	17.3	22.8	0.0	4.4	0.0	8.5	0.0	4.7	6.2	2.7	6.8	2.4	7.2	1.7	13.3	0.0	2.4	6.6	0.0	2.7	0.0	0.0	1.8	8.0	**215**
14	0.0	17.5	1.9	6.1	76.1	0.0	18.4	24.2	0.0	4.7	0.0	9.1	0.0	5.0	6.6	2.8	7.3	2.6	7.7	1.8	14.1	0.0	2.6	7.0	0.0	2.8	0.0	0.0	1.9	8.6	**229**
15	0.0	17.5	1.9	6.1	76.1	0.0	18.4	24.2	0.0	4.7	0.0	9.1	0.0	5.0	6.6	2.8	7.3	2.6	7.7	1.8	14.1	0.0	2.6	7.0	0.0	2.8	0.0	0.0	1.9	8.6	**229**
16	0.0	17.6	1.9	6.2	76.5	0.0	18.5	24.3	0.0	4.7	0.0	9.1	0.0	5.0	6.7	2.8	7.3	2.6	7.7	1.8	14.2	0.0	2.6	7.1	0.0	2.8	0.0	0.0	1.9	8.6	**230**
17	0.0	17.8	2.0	6.2	77.1	0.0	18.7	24.6	0.0	4.7	0.0	9.2	0.0	5.1	6.7	2.9	7.4	2.6	7.8	1.8	14.3	0.0	2.6	7.1	0.0	2.9	0.0	0.0	2.0	8.7	**232**
18	0.0	18.9	2.1	6.6	82.1	0.0	19.9	26.1	0.0	5.1	0.0	9.8	0.0	5.4	7.1	3.1	7.8	2.8	8.3	1.9	15.3	0.0	2.8	7.6	0.0	3.1	0.0	0.0	2.1	9.2	**247**
19	0.0	20.8	2.3	7.3	90.1	0.0	21.8	28.7	0.0	5.5	0.0	10.7	0.0	5.9	7.8	3.3	8.6	3.1	9.1	2.1	16.7	0.0	3.1	8.3	0.0	3.3	0.0	0.0	2.3	10.1	**271**
20	0.0	21.5	2.4	7.5	93.4	0.0	22.6	29.7	0.0	5.8	0.0	11.1	0.0	6.1	8.1	3.5	8.9	3.2	9.4	2.2	17.4	0.0	3.2	8.6	0.0	3.5	0.0	0.0	2.4	10.5	**281**
21	0.0	21.7	2.4	7.6	94.2	0.0	22.8	30.0	0.0	5.8	0.0	11.2	0.0	6.2	8.2	3.5	9.0	3.2	9.5	2.2	17.5	0.0	3.2	8.7	0.0	3.5	0.0	0.0	2.4	10.6	**283**
22	0.0	21.4	2.4	7.5	92.7	0.0	22.4	29.5	0.0	5.7	0.0	11.0	0.0	6.1	8.1	3.4	8.9	3.2	9.4	2.2	17.2	0.0	3.2	8.6	0.0	3.4	0.0	0.0	2.4	10.4	**279**
23	0.0	19.8	2.2	6.9	85.8	0.0	20.8	27.3	0.0	5.3	0.0	10.2	0.0	5.6	7.5	3.2	8.2	2.9	8.6	2.0	15.9	0.0	2.9	7.9	0.0	3.2	0.0	0.0	2.2	9.6	**258**
24	0.0	18.5	2.0	6.5	80.1	0.0	19.4	25.5	0.0	4.9	0.0	9.5	0.0	5.3	7.0	3.0	7.7	2.7	8.1	1.9	14.9	0.0	2.7	7.4	0.0	3.0	0.0	0.0	2.0	9.0	**241**

A.3: 29x29 bus impedance matrix ([R]+j[X]) elements

R matrix elements for each row and 29 columns are separated by semicolon

R = [

0.00098273	-0.003165246	-0.001753739	0.000219085	-0.00118701	-0.000690466
- 0.001187708	-0.001236093	-0.00126205	-0.0012360	-0.001746489	-0.00174648
-0.001706084	-0.001611003	-0.001529383	-0.001338105	-0.001485975	-0.001411323
-0.00137161	-0.001273366	-0.001277032	-0.00148975	-0.001329969	-0.001188523
-0.001188523	-0.001110206	-0.001192436	-0.001110206	-0.001110206;	

-0.003165246	0.010194845	0.005648565	-0.000705643	0.003823208	0.002223902
0.003825452	0.003981295	0.004064899	0.003981295	0.005625213	0.005625213
0.005495074	0.005188829	0.004925943	0.004309861	0.004786133	0.004545688
0.004417777	0.004101345	0.004113153	0.004798291	0.004283658	0.003828078
0.003828078	0.003575829	0.003840681	0.003575829	0.003575829;	

-0.001753739	0.005648565	0.01196281	0.002378153	0.009013544	0.006600045
0.009018479	0.009371096	0.009560186	0.009371096	0.011663591	0.011663591
0.011474485	0.011077846	0.010728046	0.009895078	0.010535481	0.010211974
0.010040069	0.009606207	0.009621088	0.010541694	0.00983397	0.009192058
0.009192058	0.008829653	0.009047522	0.008829653	0.008829653;	

0.000219085	-0.000705643	0.002378153	0.031889966	0.005285357	0.014824188
0.005280417	0.00492708	0.004737606	0.00492708	0.002688018	0.002688018
0.00287322	0.003258603	0.00359914	0.004410964	0.003787058	0.004102244
0.004269715	0.004692975	0.004678546	0.003781699	0.00447227	0.005099656
0.005099656	0.005454317	0.005251536	0.005454317	0.005454317;	

-0.001187011	0.003823208	0.009013544	0.005285357	0.015405748	0.011701978
0.015393207	0.014486964	0.014001068	0.014486964	0.010030335	0.010030335
0.010410397	0.011131815	0.01178441	0.013360994	0.012154836	0.012764478
0.013088104	0.013919443	0.013893103	0.012160283	0.013519874	0.014778511
0.014778511	0.015500386	0.015324011	0.015500386	0.015500386;	

-0.000690466	0.002223902	0.006600045	0.014824188	0.011701978	0.029715197
0.011692136	0.010981766	0.010600885	0.010981766	0.007378016	0.007378016
0.00768408	0.008272485	0.008802979	0.010082189	0.009102914	0.009597845
0.009860611	0.010534083	0.010512521	0.009105537	0.010206589	0.011223264
0.011223264	0.011805226	0.011637477	0.011805226	0.011805226;	

-0.001187708	0.003825452	0.009018479	0.005280417	0.015393207	0.011692136
0.025820228	0.014473675	0.013987384	0.014473675	0.009959827	0.009959827

0.010369564 0.011169882 0.011741586 0.013339843 0.012174895 0.012773911
0.013091958 0.013981646 0.013980775 0.012403295 0.014033174 0.016371323
0.016371323 0.017713828 0.017419328 0.017713828 0.017713828;

-0.001236093 0.003981295 0.009371096 0.00492708 0.014486964 0.010981766
0.014473675 0.022765324 0.027143303 0.022765324 0.004517017 0.004517017
0.005869231 0.009741746 0.014856325 0.023721653 0.016022201 0.019782993
0.0217899 0.025870848 0.025426939 0.012848855 0.016938253 0.009938667
0.009938667 0.006251289 0.01450336 0.006251289 0.006251289;

-0.00126205 0.004064899 0.009560186 0.004737606 0.014001068 0.010600885
0.013987384 0.027143303 0.034093524 0.027143303 0.001601319 0.001601319
0.003467652 0.009006613 0.016480896 0.029200848 0.018067442 0.023494707
0.026391811 0.032191303 0.031526563 0.013213003 0.01874605 0.007379134
0.007379134 0.001359941 0.014069362 0.001359941 0.001359941;

-0.001236093 0.003981295 0.009371096 0.00492708 0.014486964 0.010981766
0.014473675 0.022765324 0.027143303 0.022765324 0.004517017 0.004517017
0.005869231 0.009741746 0.014856325 0.023721653 0.016022201 0.019782993
0.0217899 0.025870848 0.025426939 0.012848855 0.016938253 0.009938667
0.009938667 0.006251289 0.01450336 0.006251289 0.006251289;

-0.001746489 0.005625213 0.011663591 0.002688018 0.010030335 0.007378016
0.009959827 0.004517017 0.001601319 0.004517017 0.026121318 0.026121318
0.02483313 0.019123624 0.014738363 0.005192426 0.012767861 0.008954502
0.006915231 0.002346292 0.002589337 0.013522398 0.006208341 0.000586068
0.000586068 -0.002140014 0.009727773 -0.002140014 -0.002140014;

-0.001746489 0.005625213 0.011663591 0.002688018 0.010030335 0.007378016
0.009959827 0.004517017 0.001601319 0.004517017 0.026121318 0.026121318
0.02483313 0.019123624 0.014738363 0.005192426 0.012767861 0.008954502
0.006915231 0.002346292 0.002589337 0.013522398 0.006208341 0.000586068
0.000586068 -0.002140014 0.009727773 -0.002140014 -0.002140014;

-0.001706084 0.005495074 0.011474485 0.00287322 0.010410397 0.00768408
0.010369564 0.005869231 0.003467652 0.005869231 0.02483313 0.02483313
0.113777474 0.031461933 0.01504512 0.006682348 0.021338206 0.015271268
0.012030962 0.004602214 0.00497761 0.022563959 0.01090996 0.002572933
0.002572933 -0.001720494 0.010297978 -0.001720494 -0.001720494;

-0.001611003 0.005188829 0.011077846 0.003258603 0.011131815 0.008272485
0.011169882 0.009741746 0.009006613 0.009741746 0.019123624 0.019123624
0.031461933 0.057523355 0.014328092 0.01042346 0.040116678 0.02971782
0.024182666 0.010993356 0.011647038 0.042078409 0.021740491 0.008772272
0.008772272 0.001693649 0.011492985 0.001693649 0.001693649;

-0.001529383 0.004925943 0.010728046 0.00359914 0.01178441 0.008802979
0.011741586 0.014856325 0.016480896 0.014856325 0.014738363 0.014738363
0.01504512 0.014328092 0.067402332 0.030869047 0.015071847 0.01550939
0.015738365 0.015988654 0.015810575 0.013312846 0.012017172 0.00381917
0.00381917 -0.00039214 0.011659773 -0.00039214 -0.00039214;

-0.001338105 0.004309861 0.009895078 0.004410964 0.013360994 0.010082189
0.013339843 0.023721653 0.029200848 0.023721653 0.005192426 0.005192426
0.006682348 0.01042346 0.030869047 0.053005083 0.017188825 0.021237243
0.023396056 0.02768088 0.027149287 0.013215088 0.016902238 0.006436411
0.006436411 0.000928064 0.013378752 0.000928064 0.000928064;

-0.001485975 0.004786133 0.010535481 0.003787058 0.012154836 0.009102914
0.012174895 0.016022201 0.018067442 0.016022201 0.012767861 0.012767861
0.021338206 0.040116678 0.015071847 0.017188825 0.100885027 0.073282108
0.058598841 0.018648652 0.018826735 0.031746263 0.020725253 0.008310193
0.008310193 0.00159806 0.012414142 0.00159806 0.00159806;

-0.001411323 0.004545688 0.010211974 0.004102244 0.012764478 0.009597845
0.012773911 0.019782993 0.023494707 0.019782993 0.008954502 0.008954502
0.015271268 0.02971782 0.01550939 0.021237243 0.073282108 0.099311734
0.079169249 0.023233811 0.023127157 0.025579481 0.020132745 0.008043087
0.008043087 0.001546672 0.012963692 0.001546672 0.001546672;

-0.00137161 0.004417777 0.010040069 0.004269715 0.013088104 0.009860611
0.013091958 0.0217899 0.026391811 0.0217899 0.006915231 0.006915231
0.012030962 0.024182666 0.015738365 0.023396056 0.058598841 0.079169249
0.090124332 0.025681269 0.025422699 0.022300298 0.019825461 0.007906084
0.007906084 0.001522627 0.013255772 0.001522627 0.001522627;

-0.001273366 0.004101345 0.009606207 0.004692975 0.013919443 0.010534083
0.013981646 0.025870848 0.032191303 0.025870848 0.002346292 0.002346292
0.004602214 0.010993356 0.015988654 0.02768088 0.018648652 0.023233811
0.025681269 0.053554308 0.049040765 0.018717528 0.028887499 0.01212974
0.01212974 0.002931358 0.014454814 0.002931358 0.002931358;

-0.001277032 0.004113153 0.009621088 0.004678546 0.013893103 0.010512521
0.013980775 0.025426939 0.031526563 0.025426939 0.002589337 0.002589337
0.00497761 0.011647038 0.015810575 0.027149287 0.018826735 0.023127157
0.025422699 0.049040765 0.054846269 0.020547461 0.032268917 0.013745409
0.013745409 0.003503284 0.014584693 0.003503284 0.003503284;

-0.00148975 0.004798291 0.010541694 0.003781699 0.012160283 0.009105537
0.012403295 0.012848855 0.013213003 0.012848855 0.013522398 0.013522398
0.022563959 0.042078409 0.013312846 0.013215088 0.031746263 0.025579481

0.022300298	0.018717528	0.020547461	0.102384255	0.050022009	0.02316138
0.02316138	0.007852913	0.013774623	0.007852913	0.007852913;	

-0.001329969	0.004283658	0.00983397	0.00447227	0.013519874	0.010206589
0.014033174	0.016938253	0.01874605	0.016938253	0.006208341	0.006208341
0.01090996	0.021740491	0.012017172	0.016902238	0.020725253	0.020132745
0.019825461	0.028887499	0.032268917	0.050022009	0.087372339	0.042099152
0.042099152	0.015888386	0.01678806	0.015888386	0.015888386;	

-0.001188523	0.003828078	0.009192058	0.005099656	0.014778511	0.011223264
0.016371323	0.009938667	0.007379134	0.009938667	0.000586068	0.000586068
0.002572933	0.008772272	0.00381917	0.006436411	0.008310193	0.008043087
0.007906084	0.01212974	0.013745409	0.02316138	0.042099152	0.115114085
0.115114085	0.047137629	0.02461092	0.047137629	0.047137629;	

-0.001188523	0.003828078	0.009192058	0.005099656	0.014778511	0.011223264
0.016371323	0.009938667	0.007379134	0.009938667	0.000586068	0.000586068
0.002572933	0.008772272	0.00381917	0.006436411	0.008310193	0.008043087
0.007906084	0.01212974	0.013745409	0.02316138	0.042099152	0.115114085
0.369514085	0.047137629	0.02461092	0.047137629	0.047137629;	

-0.001110206	0.003575829	0.008829653	0.005454317	0.015500386	0.011805226
0.017713828	0.006251289	0.001359941	0.006251289	-0.002140014	-0.002140014
-0.001720494	0.001693649	-0.00039214	0.000928064	0.00159806	0.001546672
0.001522627	0.002931358	0.003503284	0.007852913	0.015888386	0.047137629
0.047137629	0.063701542	0.029123983	0.063701542	0.063701542;	

-0.001192436	0.003840681	0.009047522	0.005251536	0.015324011	0.011637477
0.017419328	0.01450336	0.014069362	0.01450336	0.009727773	0.009727773
0.010297978	0.011492985	0.011659773	0.013378752	0.012414142	0.012963692
0.013255772	0.014454814	0.014584693	0.013774623	0.01678806	0.02461092
0.02461092	0.029123983	0.028613854	0.029123983	0.029123983;	

-0.001110206	0.003575829	0.008829653	0.005454317	0.015500386	0.011805226
0.017713828	0.006251289	0.001359941	0.006251289	-0.002140014	-0.002140014
-0.001720494	0.001693649	-0.00039214	0.000928064	0.00159806	0.001546672
0.001522627	0.002931358	0.003503284	0.007852913	0.015888386	0.047137629
0.047137629	0.063701542	0.029123983	0.221555203	0.153944076;	

-0.001110206	0.003575829	0.008829653	0.005454317	0.015500386	0.011805226
0.017713828	0.006251289	0.001359941	0.006251289	-0.002140014	-0.002140014
-0.001720494	0.001693649	-0.00039214	0.000928064	0.00159806	0.001546672
0.001522627	0.002931358	0.003503284	0.007852913	0.015888386	0.047137629
0.047137629	0.063701542	0.029123983	0.153944076	0.252439006]	

<u>X matrix elements for each row and 29 columns are separated by semicolon</u>

X=	[0.048529764	0.028891964	0.035030121	0.043437761	0.038298744	0.040419731
	0.038289021	0.037570788	0.037185811	0.037570788	0.036211001	0.036211001
	0.036351854	0.036472617	0.036616869	0.03701244	0.036722042	0.036869521
	0.036947138	0.037176592	0.037173736	0.036758776	0.03714113	0.03754668
	0.03754668	0.037801664	0.038242422	0.037801664	0.037801664;	
	0.028891964	0.092142755	0.072372552	0.045292639	0.061844744	0.055013321
	0.061876062	0.064189396	0.065429356	0.064189396	0.068569091	0.068569091
	0.068115422	0.067726459	0.067261843	0.06598776	0.066923095	0.066448084
	0.066198091	0.065459051	0.065468249	0.066804781	0.065573268	0.064267045
	0.064267045	0.063445772	0.062026149	0.063445772	0.063445772;	
	0.035030121	0.072372552	0.086780537	0.054611783	0.07422838	0.066112939
	0.074265947	0.077041582	0.078529333	0.077041582	0.082200385	0.082200385
	0.081663152	0.081216417	0.080675457	0.079184553	0.080277352	0.07972227
	0.079430234	0.078562508	0.078572747	0.080133958	0.078687105	0.077146042
	0.077146042	0.076174681	0.074445663	0.076174681	0.076174681;	
	0.043437761	0.045292639	0.054611783	0.154487863	0.066730675	0.102989359
	0.066694387	0.064013208	0.062576086	0.064013208	0.059037345	0.059037345
	0.059555751	0.05998575	0.060507033	0.061944299	0.06089095	0.061426001
	0.061707491	0.062544229	0.062534399	0.061029574	0.062424827	0.063911435
	0.063911435	0.064848663	0.066520815	0.064848663	0.064848663;	
	0.038298744	0.061844744	0.07422838	0.066730675	0.095155605	0.083388464
	0.095092538	0.090431579	0.087933296	0.090431579	0.081951036	0.081951036
	0.082839719	0.08355204	0.084429139	0.086861052	0.08508184	0.08598578
	0.086461165	0.087882245	0.087866563	0.085325353	0.087696619	0.090234748
	0.090234748	0.09183928	0.094791444	0.09183928	0.09183928;	
	0.040419731	0.055013321	0.066112939	0.102989359	0.083388464	0.139536299
	0.083336454	0.079492764	0.077432538	0.079492764	0.072477771	0.072477771
	0.073212214	0.073804089	0.074531079	0.076545007	0.075071194	0.075819949
	0.076213746	0.07738989	0.07737678	0.075271688	0.077234034	0.079332967
	0.079332967	0.080659286	0.083088073	0.080659286	0.080659286;	
	0.038289021	0.061876062	0.074265947	0.066694387	0.095092538	0.083336454
	0.131136071	0.091089433	0.088972407	0.091089433	0.082700753	0.082700753
	0.083715761	0.08453899	0.08530045	0.087849417	0.086087293	0.087002237
	0.087483451	0.089109471	0.089153142	0.086762392	0.089735143	0.094386278
	0.094386278	0.097327329	0.102753624	0.097327329	0.097327329;	

0.037570788	0.064189396	0.077041582	0.064013208	0.090431579	0.079492764
0.091089433	0.233576995	0.199278898	0.233576995	0.138039967	0.138039967
0.144495346	0.15022808	0.163636123	0.188452388	0.167404889	0.177566571
0.182917723	0.193706569	0.191941622	0.158316697	0.169122283	0.140989472
0.140989472	0.123366953	0.094250678	0.123366953	0.123366953;	

0.037185811	0.065429356	0.078529333	0.062576086	0.087933296	0.077432538
0.088972407	0.199278898	0.258163591	0.199278898	0.167702382	0.167702382
0.177101687	0.185489447	0.205524431	0.242178575	0.210941117	0.22599872
0.233928402	0.249671355	0.246981316	0.196917889	0.212183932	0.167830913
0.167830913	0.140040241	0.093964696	0.140040241	0.140040241;	

0.037570788	0.064189396	0.077041582	0.064013208	0.090431579	0.079492764
0.091089433	0.233576995	0.199278898	0.441576995	0.138039967	0.138039967
0.144495346	0.15022808	0.163636123	0.188452388	0.167404889	0.177566571
0.182917723	0.193706569	0.191941622	0.158316697	0.169122283	0.140989472
0.140989472	0.123366953	0.094250678	0.123366953	0.123366953;	

0.036211001	0.068569091	0.082200385	0.059037345	0.081951036	0.072477771
0.082700753	0.138039967	0.167702382	0.138039967	0.24813359	0.24813359
0.236888036	0.226478157	0.214449724	0.181878721	0.205884567	0.19369881
0.187280182	0.168548677	0.168812881	0.203133701	0.171970102	0.139272167
0.139272167	0.118848683	0.086311306	0.118848683	0.118848683;	

0.036211001	0.068569091	0.082200385	0.059037345	0.081951036	0.072477771
0.082700753	0.138039967	0.167702382	0.138039967	0.24813359	0.38813359
0.236888036	0.226478157	0.214449724	0.181878721	0.205884567	0.19369881
0.187280182	0.168548677	0.168812881	0.203133701	0.171970102	0.139272167
0.139272167	0.118848683	0.086311306	0.118848683	0.118848683;	

0.036351854	0.068115422	0.081663152	0.059555751	0.082839719	0.073212214
0.083715761	0.144495346	0.177101687	0.144495346	0.236888036	0.236888036
0.368827452	0.261990517	0.21188984	0.187665375	0.232256639	0.214664541
0.205399508	0.179143146	0.179785085	0.230207908	0.187771413	0.150041884
0.150041884	0.126432448	0.087928768	0.126432448	0.126432448;	

0.036472617	0.067726459	0.081216417	0.05998575	0.08355204	0.073804089
0.08453899	0.15022808	0.185489447	0.15022808	0.226478157	0.226478157
0.261990517	0.291584942	0.209282305	0.192694109	0.254468778	0.232520039
0.220967025	0.188537073	0.18949336	0.252915071	0.201252079	0.15971267
0.15971267	0.133630747	0.089273422	0.133630747	0.133630747;	

0.036616869	0.067261843	0.080675457	0.060507033	0.084429139	0.074531079
0.08530045	0.163636123	0.205524431	0.163636123	0.214449724	0.214449724
0.21188984	0.209282305	0.326571541	0.242364136	0.207954572	0.207166234

0.206749423	0.202457302	0.201484386	0.200510478	0.188807765	0.151256563
0.151256563	0.12776104	0.089491021	0.12776104	0.12776104;	

0.03701244	0.06598776	0.079184553	0.061944299	0.086861052	0.076545007
0.087849417	0.188452388	0.242178575	0.188452388	0.181878721	0.181878721
0.187665375	0.192694109	0.242364136	0.301055047	0.210018643	0.220266715
0.225662775	0.235330634	0.233161353	0.198000274	0.205093763	0.162813216
0.162813216	0.136329746	0.092599061	0.136329746	0.136329746;	

0.036722042	0.066923095	0.080277352	0.06089095	0.08508184	0.075071194
0.086087293	0.167404889	0.210941117	0.167404889	0.205884567	0.205884567
0.232256639	0.254468778	0.207954572	0.210018643	0.381332915	0.32715139
0.298636643	0.209946976	0.209626462	0.233336183	0.205103475	0.162569996
0.162569996	0.135884065	0.090913147	0.135884065	0.135884065;	

0.036869521	0.066448084	0.07972227	0.061426001	0.08598578	0.075819949
0.087002237	0.177566571	0.22599872	0.177566571	0.19369881	0.19369881
0.214664541	0.232520039	0.207166234	0.220266715	0.32715139	0.383113781
0.344571448	0.222613329	0.221537488	0.221760833	0.207387573	0.164263877
0.164263877	0.137219252	0.091882449	0.137219252	0.137219252;	

0.036947138	0.066198091	0.079430234	0.061707491	0.086461165	0.076213746
0.087483451	0.182917723	0.233928402	0.182917723	0.187280182	0.187280182
0.205399508	0.220967025	0.206749423	0.225662775	0.298636643	0.344571448
0.368752583	0.229283678	0.227810094	0.215669556	0.208593676	0.165157924
0.165157924	0.137923613	0.092392447	0.137923613	0.137923613;	

0.037176592	0.065459051	0.078562508	0.062544229	0.087882245	0.07738989
0.089109471	0.193706569	0.249671355	0.193706569	0.168548677	0.168548677
0.179143146	0.188537073	0.202457302	0.235330634	0.209946976	0.222613329
0.229283678	0.290696468	0.280006889	0.208061416	0.234145472	0.182664123
0.182664123	0.150323815	0.094994403	0.150323815	0.150323815;	

0.037173736	0.065468249	0.078572747	0.062534399	0.087866563	0.07737678
0.089153142	0.191941622	0.246981316	0.191941622	0.168812881	0.168812881
0.179785085	0.18949336	0.201484386	0.233161353	0.209626462	0.221537488
0.227810094	0.280006889	0.29039768	0.211570314	0.241065697	0.187352801
0.187352801	0.153586391	0.095319498	0.153586391	0.153586391;	

0.036758776	0.066804781	0.080133958	0.061029574	0.085325353	0.075271688
0.086762392	0.158316697	0.196917889	0.158316697	0.203133701	0.203133701
0.230207908	0.252915071	0.200510478	0.198000274	0.233336183	0.221760833
0.215669556	0.208061416	0.211570314	0.369586175	0.255549552	0.197223579
0.197223579	0.160399734	0.093629251	0.160399734	0.160399734;	

0.03714113	0.065573268	0.078687105	0.062424827	0.087696619	0.077234034
0.089735143	0.169122283	0.212183932	0.169122283	0.171970102	0.171970102
0.187771413	0.201252079	0.188807765	0.205093763	0.205103475	0.207387573
0.208593676	0.234145472	0.241065697	0.255549552	0.328134652	0.247334275
0.247334275	0.196133154	0.099452227	0.196133154	0.196133154;	

0.03754668	0.064267045	0.077146042	0.063911435	0.090234748	0.079332967
0.094386278	0.140989472	0.167830913	0.140989472	0.139272167	0.139272167
0.150041884	0.15971267	0.151256563	0.162813216	0.162569996	0.164263877
0.165157924	0.182664123	0.187352801	0.197223579	0.247334275	0.418276641
0.418276641	0.317367127	0.114097664	0.317367127	0.317367127;	

0.03754668	0.064267045	0.077146042	0.063911435	0.090234748	0.079332967
0.094386278	0.140989472	0.167830913	0.140989472	0.139272167	0.139272167
0.150041884	0.15971267	0.151256563	0.162813216	0.162569996	0.164263877
0.165157924	0.182664123	0.187352801	0.197223579	0.247334275	0.418276641
0.798276641	0.317367127	0.114097664	0.317367127	0.317367127;	

0.037801664	0.063445772	0.076174681	0.064848663	0.09183928	0.080659286
0.097327329	0.123366953	0.140040241	0.123366953	0.118848683	0.118848683
0.126432448	0.133630747	0.12776104	0.136329746	0.135884065	0.137219252
0.137923613	0.150323815	0.153586391	0.160399734	0.196133154	0.317367127
0.317367127	0.393333972	0.123369159	0.393333972	0.393333972;	

0.038242422	0.062026149	0.074445663	0.066520815	0.094791444	0.083088073
0.102753624	0.094250678	0.093964696	0.094250678	0.086311306	0.086311306
0.087928768	0.089273422	0.089491021	0.092599061	0.090913147	0.091882449
0.092392447	0.094994403	0.095319498	0.093629251	0.099452227	0.114097664
0.114097664	0.123369159	0.140694291	0.123369159	0.123369159;	

0.037801664	0.063445772	0.076174681	0.064848663	0.09183928	0.080659286
0.097327329	0.123366953	0.140040241	0.123366953	0.118848683	0.118848683
0.126432448	0.133630747	0.12776104	0.136329746	0.135884065	0.137219252
0.137923613	0.150323815	0.153586391	0.160399734	0.196133154	0.317367127
0.317367127	0.393333972	0.123369159	0.69140839	0.563456654;	

0.037801664	0.063445772	0.076174681	0.064848663	0.09183928	0.080659286
0.097327329	0.123366953	0.140040241	0.123366953	0.118848683	0.118848683
0.126432448	0.133630747	0.12776104	0.136329746	0.135884065	0.137219252
0.137923613	0.150323815	0.153586391	0.160399734	0.196133154	0.317367127
0.317367127	0.393333972	0.123369159	0.563456654	0.749145587]	

A.4 : OPF sample output for using units scheduled by Classical Lagrange for a peak hour in loading scenario-1 of Table 5.5

Converged in 0.25 seconds

Objective Function Value = 918.19 $/hr

```
================================================================================
|                              System Summary                                  |
================================================================================
How many?                  How much?              P (MW)          Q (MVAr)
---------------------      -------------------    -------------   -----------------
Buses              30      Total Gen Capacity     435.0           -95.0 to 600.0
Generators          6      On-line Capacity       365.0           -70.0 to 490.0
Committed Gens      4      Generation (actual)    324.5             139.4
Loads              21      Load                   311.7             138.8
Fixed              21      Fixed                  311.7             138.8
Dispatchable        0      Dispatchable           -0.0 of -0.0       -0.0
Shunts              2      Shunt (inj)             -0.0               21.6
Branches           40      Losses (I^2 * Z)        12.77              57.77
Transformers        3      Branch Charging (inj)    -                 35.6
Inter-ties          0      Total Inter-tie Flow     0.0                0.0
Areas               1
```

	Minimum	Maximum
	------------------------	-------------------------------
Voltage Magnitude	0.940 p.u. @ bus 26	1.060 p.u. @ bus 1
Voltage Angle	-17.61 deg @ bus 19	0.00 deg @ bus 1
P Losses (I^2*R)	-	2.71 MW @ line 1-2
Q Losses (I^2*X)	-	9.61 MVAr @ line 2-5

==

| Bus Data |

==

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
1	1.060	0.000*	195.67	-20.00	-	-
2	1.051	-3.881	65.85	24.69	23.87	13.97
3	1.027	-6.079	-	-	2.64	1.32
4	1.019	-7.466	-	-	8.36	1.76
5	1.060	-11.573	28.00	74.71	103.62	20.90
6	1.022	-8.690	-	-	-	-
7	1.029	-10.417	-	-	25.08	11.99
8	1.032	-8.923	35.00	60.00	33.00	33.00
9	0.984	-13.723	-	-	-	-
10	0.967	-16.534	-	-	6.38	2.20
11	0.984	-13.723	-	-	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
12	0.970	-14.857	-	-	12.32	8.25
13	0.970	-14.857	-	-	-	-
14	0.954	-16.055	-	-	6.82	1.76
15	0.950	-16.257	-	-	9.02	2.75
16	0.959	-15.939	-	-	3.85	1.98
17	0.959	-16.619	-	-	9.90	6.38
18	0.942	-17.262	-	-	3.52	0.99
19	0.940	-17.609	-	-	10.45	3.74
20	0.946	-17.416	-	-	2.42	0.77
21	0.953	-17.004	-	-	19.25	12.32
22	0.954	-16.954	-	-	-	-
23	0.944	-16.780	-	-	3.52	1.76
24	0.945	-17.022	-	-	9.57	7.37
25	0.961	-15.932	-	-	-	-
26	0.940	-16.452	-	-	3.85	2.53
27	0.981	-14.936	-	-	-	-
28	1.018	-9.309	-	-	-	-
29	0.958	-16.415	-	-	2.64	0.99
30	0.944	-17.484	-	-	11.66	2.09
			--------	--------	--------	--------
		Total:	324.51	139.41	311.74	138.82

OPF sample output for using units scheduled by proposed method of scheduling for a peak hour in loading scenario-1 of Table 5.5

Converged in 0.30 seconds

Objective Function Value = 916.17 $/hr

==

| System Summary |

==

How many?		How much?	P (MW)	Q (MVAr)
Buses	30	Total Gen Capacity	435.0	-95.0 to 600.0
Generators	6	On-line Capacity	395.0	-80.0 to 540.0
Committed Gens	5	Generation (actual)	323.8	134.6
Loads	21	Load	311.7	138.8
Fixed	21	Fixed	311.7	138.8
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	2	Shunt (inj)	-0.0	22.8
Branches	40	Losses (I^2 * Z)	12.07	53.75
Transformers	3	Branch Charging (inj)	-	35.2
Inter-ties	0	Total Inter-tie Flow	0.0	0.0
Areas	1			

	Minimum	Maximum
Voltage Magnitude	0.953 p.u. @ bus 30	1.060 p.u. @ bus 1
Voltage Angle	-16.95 deg @ bus 30	0.00 deg @ bus 1
P Losses (I^2*R)	-	2.87 MW @ line 1-2
Q Losses (I^2*X)	-	8.86 MVAr @ line 2-5

==

| Bus Data |

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Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
1	1.060	0.000*	199.53	-14.69	-	-
2	1.047	-3.970	55.58	35.51	23.87	13.97
3	1.028	-6.036	-	-	2.64	1.32
4	1.020	-7.412	-	-	8.36	1.76
5	1.019	-11.372	23.71	34.67	103.62	20.90
6	1.022	-8.614	-	-	-	-
7	1.012	-10.315	-	-	25.08	11.99
8	1.031	-8.827	35.00	57.29	33.00	33.00
9	1.017	-12.827	-	-	-	-
10	0.996	-15.735	-	-	6.38	2.20
11	1.060	-11.722	10.00	21.77	-	-

12	0.984	-14.261	-	-	12.32	8.25

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
13	0.984	-14.261	-	-	-	-
14	0.970	-15.394	-	-	6.82	1.76
15	0.968	-15.594	-	-	9.02	2.75
16	0.980	-15.276	-	-	3.85	1.98
17	0.985	-15.839	-	-	9.90	6.38
18	0.963	-16.513	-	-	3.52	0.99
19	0.964	-16.817	-	-	10.45	3.74
20	0.971	-16.619	-	-	2.42	0.77
21	0.981	-16.204	-	-	19.25	12.32
22	0.981	-16.164	-	-	-	-
23	0.963	-16.081	-	-	3.52	1.76
24	0.966	-16.292	-	-	9.57	7.37
25	0.974	-15.347	-	-	-	-
26	0.954	-15.853	-	-	3.85	2.53
27	0.989	-14.449	-	-	-	-
28	1.018	-9.206	-	-	-	-
29	0.966	-15.903	-	-	2.64	0.99
30	0.953	-16.954	-	-	11.66	2.09
			--------	--------	--------	--------
		Total:	323.81	134.55	311.74	138.82

APPENDIX: B
Bangladesh Power System (BPS) Related Data

B.1 Network data

Table B.1.1: Bus data (Demand data for a peak hour in loading scenario-1)

bus_i	type	Pd MW	Qd MVAR	Gs pu	Bs pu	base kV
1	3	16.65	10.32	0	0	132
2	1	10.6	6.57	0	0	132
3	2	58	35.95	0	80	132
4	2	21	13.01	0	0	132
5	1	26	16.11	0	0	132
6	2	30	18.59	0	30	132
7	1	24	14.87	0	35	132
8	2	78	48.34	0	20	132
9	1	130	80.57	0	15	132
10	2	58	35.95	0	35	132
11	1	84	52.06	0	35	132
12	2	10	6.19	0	0	132
13	1	0	0	0	0	132
14	2	50	30.99	0	25	132
15	1	73	45.24	0	25	132
16	1	61	37.8	0	0	132
17	2	113	70.03	0	50	132
18	1	37	22.93	0	0	132
19	1	45.47	28.18	0	0	132

type1: PQ bus

type2: PV bus

type3: Slack bus

Gs: Shunt conductance

Bs: Shunt capacitor susceptance

20	1	85.8	53.17	0	0	132
21	1	113.1	70.09	0	0	132
22	1	0	0	0	0	132
23	1	105	65.07	0	20	132
24	1	97.5	60.43	0	0	132
25	1	0	0	0	90	132
26	1	102	63.21	0	0	132
27	1	16.77	10.39	0	0	132
28	2	110	68.17	0	0	132
29	2	45	27.89	0	15	132
30	2	71	44	0	60	132
31	1	70	43.38	0	0	132
32	1	65	40.28	0	0	132
33	1	83	51.44	0	0	132
34	1	129.35	80.16	0	25	132
35	1	156	96.68	0	50	132
36	2	98.67	61.15	0	0	132
37	1	80	49.58	0	0	132
38	2	55.46	34.37	0	20	132
39	1	87	53.92	0	45	132
40	1	114	70.65	0	25	132
41	2	80	49.58	0	25	132
42	2	54	33.47	0	0	132
43	1	100	61.97	0	37.5	132
44	2	95	58.88	0	25	132
45	1	0	0	0	90	132
46	2	63.4	39.29	0	0	132
47	1	39	24.17	0	0	132
48	2	97	60.11	0	0	132

49	1	81	50.2	0	25	132
50	1	29	17.97	0	0	132
51	2	30.86	19.13	0	0	132
52	1	30	18.59	0	0	132
53	1	27.76	17.2	0	0	132
54	2	0	0	0	0	132
55	2	111	68.79	0	10	132
56	1	21	13.01	0	0	132
57	2	1.2	0.74	0	0	132
58	1	70	43.38	0	20	132
59	2	30	18.59	0	0	132
60	1	65	40.28	0	60	132
61	1	44	27.27	0	17.5	132
62	1	40	24.79	0	25	132
63	2	4.58	2.84	0	0	132
64	2	50	30.99	0	5	132
65	1	13.2	8.18	0	0	132
66	1	38	23.55	0	57.5	132
67	2	36.77	22.79	0	60	132
68	1	20	12.39	0	0	132
69	1	33	20.45	0	25	132
70	1	20	12.39	0	0	132
71	2	15.5	9.61	0	25	132
72	1	0	0	0	45	132
73	1	19.7	12.21	0	12.5	132
74	2	25	15.49	0	60	132
75	1	50	30.98	0	37.5	132
76	2	65	40.28	0	60	132
77	2	44	27.27	0	40	132

78	1	50	30.99	0	0	132
79	2	28	17.35	0	0	132
80	1	34.56	21.42	0	0	132
81	1	27.51	17.05	0	12.5	132
82	2	113	70.03	0	20	132
83	1	73	45.24	0	40	132
84	1	23	14.25	0	0	132
85	2	58	35.94	0	30	132
86	1	22.4	13.88	0	12.5	132
87	2	40.79	25.28	0	35	132
88	1	24.36	15.1	0	15	132
89	2	43	26.65	0	35	132
90	1	0	0	0	0	132
91	1	14	8.68	0	0	132
92	1	7	4.34	0	0	132
93	1	0	0	0	0	132
94	1	33.8	20.95	0	20	132
95	1	30	18.59	0	0	132
96	1	24.8	15.37	0	0	132
97	2	30.88	19.14	0	0	230
98	1	0	0	0	0	230
99	1	0	0	0	0	230
100	2	38.05	23.58	0	0	230
101	2	67.73	41.98	0	0	230
102	1	0	0	0	0	230
103	2	0	0	0	0	230
104	1	0	0	0	0	230
105	2	44.82	27.78	0	0	230
106	1	0	0	0	0	230

107	1	0	0	0	0	230
108	1	0	0	0	0	230
109	1	0	0	0	0	230
110	1	0	0	0	0	230
111	1	0	0	0	0	230
112	1	0	0	0	0	230
113	1	0	0	0	0	230
114	2	0	0	0	0	230
115	1	12.45	7.72	0	0	230
116	2	0	0	0	0	132
117	2	0	0	0	0	132
118	2	0	0	0	0	132
119	2	0	0	0	0	132
120	2	0	0	0	0	132
121	2	0	0	0	0	132
122	2	0	0	0	0	132
123	2	0	0	0	0	132
124	2	0	0	0	0	132
125	2	0	0	0	0	132
126	2	0	0	0	0	132
127	2	0	0	0	0	132
128	2	0	0	0	0	132
129	2	0	0	0	0	132
130	2	0	0	0	0	132
131	2	0	0	0	0	132
132	2	0	0	0	0	132
133	2	0	0	0	0	132
134	2	0	0	0	0	132
135	2	0	0	0	0	132

136	2	0	0	0	0	132
137	2	0	0	0	0	132
138	2	0	0	0	0	132
139	2	0	0	0	0	132
140	2	0	0	0	0	132
141	2	0	0	0	0	132
142	2	0	0	0	0	132
143	2	0	0	0	0	132
144	2	0	0	0	0	132
145	2	0	0	0	0	132
146	2	0	0	0	0	132
147	2	0	0	0	0	132
148	2	0	0	0	0	132
149	2	0	0	0	0	132
150	2	0	0	0	0	230
151	2	0	0	0	0	230
152	2	0	0	0	0	230
153	2	0	0	0	0	230
154	2	0	0	0	0	230
155	2	0	0	0	0	230
156	2	0	0	0	0	230
157	2	0	0	0	0	230
158	2	0	0	0	0	230
159	2	0	0	0	0	230
160	2	0	0	0	0	230
161	2	0	0	0	0	230
162	2	0	0	0	0	132
163	2	0	0	0	0	132
164	2	0	0	0	0	132

165	2	0	0	0	0	132
166	2	0	0	0	0	132

Table B.1.2
:Generator data

bus	Qmax MVAR	Qmin MVAR	Vg pu	MVA Base	*status(input from scheduling method: U_i^t)	Pmax MW	Pmin MW
1	138	0	0	100	-	230	40
3	59	0	0	100	-	98	9
4	15	0	0	100	-	25	9
6	61	0	0	100	-	102	17
8	18	0	0	100	-	30	9
10	13	0	0	100	-	22	3
12	60	0	0	100	-	100	14
14	13	0	0	100	-	22	3
129	7	0	0	100	-	11	3
17	20	0	0	100	-	33	9
130	15	0	0	100	-	25	4
28	30	0	0	100	-	50	10
29	60	0	0	100	-	100	17
30	60	0	0	100	-	100	14
36	21	0	0	100	-	35	7
38	63	0	0	100	-	105	30
41	13	0	0	100	-	22	3

42	60	0	0	100	-	100	10
131	51	0	0	100	-	85	30
132	27	0	0	100	-	45	5
44	54	0	0	100	-	90	30
46	58	0	0	100	-	97	50
133	33	0	0	100	-	55	4
134	27	0	0	100	-	45	4
48	121	0	0	100	-	202	35
51	52	0	0	100	-	86	10
135	42	0	0	100	-	70	10
136	30	0	0	100	-	50	3
137	7	0	0	100	-	11	3
54	48	0	0	100	-	80	30
138	54	0	0	100	-	90	35
139	31	0	0	100	-	51	3
140	26	0	0	100	-	44	4
55	85	0	0	100	-	142	40
141	30	0	0	100	-	50	3
142	12	0	0	100	-	20	10
57	66	0	0	100	-	110	7
143	69	0	0	100	-	115	17
144	33	0	0	100	-	55	20
145	33	0	0	100	-	55	3
146	36	0	0	100	-	60	20
59	61	0	0	100	-	101	10
147	24	0	0	100	-	40	9
63	28	0	0	100	-	46	10
148	63	0	0	100	-	105	6
64	32	0	0	100	-	54	7

67	24	0	0	100	-	40	9
71	14	0	0	100	-	23	8
74	43	0	0	100	-	71	9
76	30	0	0	100	-	50	9
149	30	0	0	100	-	50	9
77	30	0	0	100	-	50	8
79	7	0	0	100	-	11	3
82	30	0	0	100	-	50	9
85	12	0	0	100	-	20	5
87	12	0	0	100	-	20	5
89	28	0	0	100	-	47	12
97	108	0	0	100	-	180	60
150	108	0	0	100	-	180	60
100	90	0	0	100	-	150	50
151	90	0	0	100	-	150	50
152	90	0	0	100	-	150	50
153	48	0	0	100	-	80	10
154	32	0	0	100	-	53	4
155	27	0	0	100	-	45	4
101	102	0	0	100	-	170	50
156	108	0	0	100	-	180	60
157	114	0	0	100	-	190	60
158	114	0	0	100	-	190	60
159	47	0	0	100	-	78	3
103	216	0	0	100	-	360	100
160	90	0	0	100	-	150	50
105	270	0	0	100	-	450	70
114	75	0	0	100	-	125	40
161	75	0	0	100	-	125	40

116	66	0	0	100	-	110	15
117	30	0	0	100	-	50	9
118	42	0	0	100	-	70	12
119	30	0	0	100	-	50	9
120	60	0	0	100	-	100	9
162	59	0	0	100	-	98	10
121	32	0	0	100	-	53	13
122	60	0	0	100	-	100	9
123	31	0	0	100	-	52	9
124	58	0	0	100	-	96	35
125	60	0	0	100	-	100	35
163	54	0	0	100	-	90	20
164	43	0	0	100	-	71	30
126	72	0	0	100	-	120	40
165	72	0	0	100	-	120	40
127	90	0	0	100	-	150	50
166	30	0	0	100	-	50	10
128	20	0	0	100	-	33	7

Table B.1.3:
Branch(line/transformer) data

from **bus**	**to** **bus**	**r** pu	**x** pu	**b** pu	**MVA** Limit
1	2	0.0046	0.0189	0.0039	150
1	3	0.0133	0.0543	0.0448	300
1	4	0.0174	0.0708	0.0146	150
2	4	0.018	0.0732	0.0151	150

3	4	0.0026	0.0106	0.0088	300
3	10	0.0035	0.0142	0.0116	300
3	14	0.0258	0.105	0.0866	300
4	5	0.0038	0.0153	0.0126	300
4	9	0.0038	0.0153	0.0126	300
5	6	0.0102	0.0413	0.034	300
5	11	0.0012	0.0047	0.0038	300
5	12	0.0029	0.0118	0.0024	150
5	13	0.0026	0.0106	0.0088	300
6	7	0.0252	0.1027	0.0846	300
8	9	0.0041	0.0165	0.0136	300
8	12	0.0046	0.0189	0.0039	150
9	10	0.0075	0.0307	0.0063	150
9	11	0.0012	0.0047	0.0038	300
9	92	0.0046	0.0189	0.0039	150
12	13	0.002	0.0083	0.0068	300
14	15	0.0093	0.0378	0.0312	300
14	16	0.0186	0.0755	0.0622	300
14	129	0.01	0.1	0	500
15	18	0.0218	0.0885	0.073	300
16	17	0.0093	0.0378	0.0078	150
16	18	0.0447	0.1817	0.0374	150
16	19	0.0209	0.085	0.07	300
17	18	0.0354	0.144	0.0296	150
17	130	0.01	0.1	0	500
10	92	0.0029	0.0118	0.0024	150
97	98	0.0012	0.0066	0.0942	1200
97	150	0.01	0.1	0	500
98	99	0.0083	0.0574	0.462	1200

99	100	0.0045	0.03	0.2418	1200
99	105	0.0023	0.016	0.2448	1200
51	52	0.0104	0.0398	0.0376	300
52	53	0.0142	0.0541	0.051	300
53	54	0.0012	0.0044	0.0011	300
54	55	0.0084	0.032	0.0302	300
54	138	0.01	0.1	0	500
54	139	0.01	0.1	0	500
54	140	0.01	0.1	0	500
55	56	0.0093	0.0354	0.0334	300
55	141	0.01	0.1	0	500
55	142	0.01	0.1	0	500
47	48	0.0171	0.0652	0.0614	300
48	49	0.016	0.0608	0.0574	300
48	50	0.0099	0.0376	0.0354	300
48	93	0.0073	0.0276	0.026	300
19	20	0.0006	0.0022	0.002	300
19	22	0.0035	0.0132	0.0124	300
19	27	0.0058	0.022	0.0052	150
19	28	0.0186	0.0704	0.0166	150
19	29	0.0075	0.0286	0.0068	150
19	42	0.0255	0.0968	0.0229	150
19	44	0.0139	0.0528	0.0125	150
20	23	0.0046	0.0176	0.0166	300
21	23	0.0035	0.0132	0.0031	150
21	25	0.0029	0.011	0.0026	150
22	27	0.0093	0.0352	0.0083	150
22	95	0.0015	0.0055	0.0521	300
23	25	0.0023	0.0088	0.0021	150

25	37	0.0032	0.0121	0.0114	300
28	30	0.011	0.0418	0.0099	150
29	31	0.0035	0.0132	0.0031	150
30	31	0.007	0.0264	0.0062	150
28	33	0.0064	0.0242	0.0057	150
30	35	0.0104	0.0396	0.0094	150
33	35	0.007	0.0264	0.0062	150
34	36	0.0075	0.0286	0.0068	150
34	38	0.0087	0.033	0.0078	150
34	45	0.0029	0.011	0.0104	300
35	45	0.0009	0.0033	0.0032	300
36	38	0.0052	0.0198	0.0047	150
37	38	0.0023	0.0088	0.0084	300
38	39	0.0067	0.0253	0.024	300
38	94	0.0009	0.0033	0.0032	300
39	40	0.0096	0.0363	0.0344	300
39	41	0.0148	0.0561	0.053	300
39	43	0.0044	0.0165	0.0156	300
42	43	0.0075	0.0286	0.027	300
42	44	0.0116	0.044	0.0104	150
42	46	0.0125	0.0473	0.0448	300
42	131	0.01	0.1	0	500
42	132	0.01	0.1	0	500
46	47	0.0151	0.0572	0.054	300
46	51	0.0151	0.0572	0.054	300
46	133	0.01	0.1	0	500
46	134	0.01	0.1	0	500
100	101	0.0033	0.0169	0.131	1200
100	112	0.0056	0.0385	0.1654	1200

100	151	0.01	0.1	0	500
100	152	0.01	0.1	0	500
100	153	0.01	0.1	0	500
100	154	0.01	0.1	0	500
100	155	0.01	0.1	0	500
101	102	0.002	0.0104	0.0804	1200
101	107	0.0035	0.0177	0.1368	1200
101	156	0.01	0.1	0	500
101	157	0.01	0.1	0	500
101	158	0.01	0.1	0	500
101	159	0.01	0.1	0	500
101	108	0.0134	0.0686	0.1482	1200
102	111	0.0025	0.0094	0.082	1200
103	105	0.0005	0.0033	0.0506	1200
103	106	0.0001	0.0008	0.0062	1200
103	107	0.001	0.0072	0.1098	1200
103	115	0.0002	0.0015	0.0031	600
103	160	0.01	0.1	0	500
104	105	0.001	0.0072	0.1098	1200
104	111	0.007	0.0264	0.025	1200
74	75	0.0087	0.033	0.001	300
74	78	0.0093	0.0352	0.0003	150
74	80	0.0916	0.3473	0.0089	150
75	76	0.0154	0.045	0.0012	300
75	82	0.0189	0.0715	0.002	300
76	77	0.0136	0.0517	0.0014	300
76	149	0.01	0.1	0	500
78	79	0.0704	0.2672	0.0069	150
79	80	0.0041	0.0154	1E-05	150

79	81	0.0203	0.077	0.0528	150
80	81	0.0116	0.044	0.0012	300
81	82	0.0192	0.0726	0.002	300
82	83	0.0131	0.0495	0.0014	300
82	84	0.0146	0.0552	0.0016	300
82	90	0.0006	0.0022	0.0016	300
84	85	0.0152	0.0576	0.0016	300
85	86	0.0222	0.0839	0.0006	150
85	87	0.0119	0.0451	0.0012	300
85	91	0.0131	0.0495	0.0014	300
87	88	0.0061	0.023	0.0008	300
87	91	0.0104	0.0396	0.0012	300
88	89	0.0126	0.0477	0.0014	300
108	109	0.0022	0.0151	0.065	1200
108	110	0.0069	0.0473	0.2032	1200
109	112	0.0016	0.011	0.0472	1200
112	113	0.0027	0.0187	0.0804	1200
113	114	0.0042	0.0289	0.124	1200
57	58	0.0003	0.0011	0.001	300
57	69	0.0126	0.1017	0.0233	150
57	143	0.01	0.1	0	500
57	144	0.01	0.1	0	500
57	145	0.01	0.1	0	500
57	146	0.01	0.1	0	500
58	59	0.0031	0.0249	0.0228	300
58	72	0.0013	0.0102	0.0094	300
59	60	0.0035	0.0283	0.0258	300
59	147	0.01	0.1	0	500
60	61	0.0063	0.0509	0.0466	300

61	62	0.006	0.0486	0.0444	300
62	63	0.0032	0.026	0.0238	300
63	64	0.0404	0.1181	0.1086	300
63	74	0.0029	0.011	0.0004	300
63	96	0.0077	0.0225	0.0052	150
63	148	0.01	0.1	0	500
64	66	0.0246	0.072	0.0662	300
65	66	0.0126	0.1017	0.0233	150
66	67	0.0216	0.063	0.058	300
67	68	0.0385	0.1125	0.0259	150
67	71	0.0215	0.0814	0.0192	150
68	69	0.0246	0.072	0.0165	150
69	70	0.0239	0.0698	0.016	150
72	73	0.0157	0.1266	0.029	150
51	118	0.0145	0.055	0.052	300
51	135	0.01	0.1	0	500
51	136	0.01	0.1	0	500
51	137	0.01	0.1	0	500
119	122	0.0093	0.0352	0.0332	300
19	122	0.0061	0.0231	0.0218	300
3	98	0	0.0215	0	675
16	99	0	0.043	0	225
46	100	0	0.0322	0	450
42	101	0	0.0484	0	450
38	102	0	0.014	0	675
19	103	0	0.014	0	675
30	104	0	0.014	0	675
25	107	0	0.014	0	675
45	111	0	0.014	0	675

74	108	0	0.0131	0	675
80	109	0	0.043	0	225
90	113	0	0.0215	0	450
91	114	0	0.0215	0	450
114	161	0.01	0.1	0	500
72	110	0	0.0215	0	450
19	116	0.01	0.1	0	500
19	124	0.01	0.1	0	500
80	117	0.01	0.1	0	500
80	125	0.01	0.1	0	500
125	163	0.01	0.1	0	500
125	164	0.01	0.1	0	500
20	120	0.01	0.1	0	500
120	162	0.01	0.1	0	500
20	126	0.01	0.1	0	500
126	165	0.01	0.1	0	500
5	121	0.01	0.1	0	500
5	127	0.01	0.1	0	500
127	166	0.01	0.1	0	500
43	123	0.01	0.1	0	500
43	128	0.01	0.1	0	500
23	24	0.0023	0.0088	0.274	150
22	26	0.0035	0.0132	0.411	150
25	32	0.0012	0.0044	0.137	150

Table B.1.4: Scheduling related data for the 93 units of BPS

Gen Sl No.	Bus No.	Location	cost characteristics coefficients a/2 ($/MW^2/h)	b ($/MWh)	c ($/h)	Fuel type	P_G^{max} MW	P_G^{min} MW
1	1	Kaptai	0	0	0	Hydro	230	40
2	3	Hathazari	0.030	111	0	Oil	98	9
3	4	Madanhat	0.200	118	0	Oil	25	9
4	6	Dohazari	0.030	111	0	Oil	102	17
5	8	Halishahar	0.200	40	0	Gas	30	9
6	10	Baraulia	0.200	36	0	Gas	22	3
7	12	Julda	0.030	110	0	Oil	100	14
8	14	Feni-1	0.200	36	0	Gas	22	3
9	129	Feni-2	0.200	36	0	Gas	11	3
10	17	Comilla(s)-1	0.200	36	0	Gas	33	9
11	130	Comilla(s)-2	0.200	36	0	Gas	25	4
12	28	Shyampur	0.500	134	0	Oil	50	10
13	29	Madanganj	0.030	113	0	Oil	100	17
14	30	Hasnabad	0.030	116	0	Oil	100	14
15	36	Uttara	0.066	36	0	Gas	35	7
16	38	Tongi	0.030	52	0	Gas	105	30
17	41	Tangail	0.200	36	0	Gas	22	3
18	42	Ghorasal-1	0.030	44	0	Gas	100	10
19	131	Ghorasal-2	0.140	44	0	Gas	85	30
20	132	Ghorasal-3	0.500	44	0	Gas	45	5
21	44	Bhulta	0.030	36	0	Gas	90	30
22	46	Ashuganj-1	0.030	44	0	Gas	97	50
23	133	Ashuganj-2	0.500	44	0	Gas	55	4
24	134	Ashuganj-3	0.500	44	0	Gas	45	4

25	48	Mymenshingh	0.030	32	0	Gas	202	35
26	51	Shahjibazar-1	0.140	52	0	Gas	86	10
27	135	Shahjibazar-2	0.140	52	0	Gas	70	10
28	136	Shahjibazar-3	0.500	52	0	Gas	50	3
29	137	Shahjibazar-4	0.200	52	0	Gas	11	3
30	54	Fenchuganj-1	0.140	40	0	Gas	80	30
31	138	Fenchuganj-2	0.140	40	0	Gas	90	35
32	139	Fenchuganj-3	0.500	40	0	Gas	51	3
33	140	Fenchuganj-4	0.500	40	0	Gas	44	4
34	55	Sylhet-1	0.030	44	0	Gas	142	40
35	141	Sylhet-2	0.500	44	0	Gas	50	3
36	142	Sylhet-3	0.200	44	0	Gas	20	10
37	57	Khulna C-1	0.030	152	0	Oil	110	7
38	143	Khulna C-2	0.030	152	0	Oil	115	17
39	144	Khulna C-3	0.500	152	0	Oil	55	20
40	145	Khulna C-4	0.500	152	0	Oil	55	3
41	146	Khulna C-5	0.500	152	0	Oil	60	20
42	59	Noapara-1	0.030	116	0	Oil	101	10
43	147	Noapara-2	0.200	116	0	Oil	40	9
44	63	Bheramara-1	0.200	167	0	Oil	46	10
45	148	Bheramara-2	0.030	167	0	Oil	105	6
46	64	Faridpur	0.500	117	0	Oil	54	7
47	67	Barisal	0.200	267	0	Oil	40	9
48	71	Bhola (nearest grid bus is Patuakhali)	0.200	48	0	Gas	23	8
49	74	Ishurdi	0.140	124	0	Oil	71	9
50	76	Rajshahi-1	0.500	115	0	Oil	50	9
51	149	Rajshahi-2	0.500	115	0	Oil	50	9
52	77	Chapai Nawabganj	0.500	113	0	Oil	50	8

53	79	Shahjadpur	0.200	36	0	Gas	11	3
54	82	Bogra	0.500	40	0	Gas	50	9
55	85	Rangpur	0.200	233	0	Oil	20	5
56	87	Saidpur	0.200	229	0	Oil	20	5
57	89	Thakurgaon	0.500	139	0	Oil	47	12
58	97	Raozan-1	0.030	44	0	Gas	180	60
59	150	Raozan-2	0.030	44	0	Gas	180	60
60	100	Ashuganj230-1	0.030	40	0	Gas	150	50
61	151	Ashuganj230-2	0.030	40	0	Gas	150	50
62	152	Ashuganj230-3	0.030	40	0	Gas	150	50
63	153	Ashuganj230-4	0.140	40	0	Gas	80	10
64	154	Ashuganj230-5	0.500	40	0	Gas	53	4
65	155	Ashuganj230-6	0.500	40	0	Gas	45	4
66	101	Ghorasal230-1	0.030	44	0	Gas	170	50
67	156	Ghorasal230-2	0.030	44	0	Gas	180	60
68	157	Ghorasal230-3	0.030	44	0	Gas	190	60
69	158	Ghorasal230-4	0.030	44	0	Gas	190	60
70	159	Ghorasal230-Rental	0.140	44	0	Gas	78	3
71	103	Haripur230-1	0.030	32	0	Gas	360	100
72	160	Haripur230-2	0.030	32	0	Gas	150	50
73	105	Meghnaghat230	0.030	32	0	Gas	450	70
74	114	Barapukuria-1	0.030	59	0	Coal	125	40
75	161	Barapukuria-2	0.030	59	0	Coal	125	40
76	116	Haripur	0.030	118	0	Oil	110	15
77	117	Baghabari	0.500	113	0	Oil	50	9
78	118	B Baria	0.140	40	0	Gas	70	12
79	119	Daudkandi	0.500	109	0	Oil	50	9
80	120	Shidhirganj-1	0.030	123	0	Oil	100	9
81	162	Shidhirganj-2	0.030	123	0	Oil	98	10

82	121	Sikalbaha	0.500	110	0	Oil	53	13
83	122	Meghnaghat132	0.030	115	0	Oil	100	9
84	123	Joydevpur	0.500	118	0	Oil	52	9
85	124	Haripur(N)	0.140	56	0	Gas	96	35
86	125	Baghabari(N)-1	0.030	48	0	Gas	100	35
87	163	Baghabari(N)-2	0.140	48	0	Gas	90	20
88	164	Baghabari(N)-3	0.140	48	0	Gas	71	30
89	126	Sidhirganj(N)-1	0.030	48	0	Gas	120	40
90	165	Sidhirganj(N)-2	0.030	48	0	Gas	120	40
91	127	Sikalbaha(N)-1	0.030	52	0	Gas	150	50
92	166	Sikalbaha(N)-2	0.500	52	0	Gas	50	10
93	128	Joydevpur(N)	0.066	36	0	Gas	33	7

B.2: Total load and bus wise load (MW) data for 24 hours (loading pattern-1)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Total Load (MW)	3442	3495	3424	3371	3442	3424	3565	3618	3689	3477	3812	3795	3795	4042	4042	4060	4095	4360	4783	4960	4995	4924	4554	4254
Bus																								
1	11.5	11.7	11.4	11.3	11.5	11.4	11.9	12.1	12.3	11.6	12.7	12.7	12.7	13.5	13.5	13.6	13.7	14.6	16.0	16.6	16.7	16.5	15.2	14.2
2	7.3	7.4	7.3	7.2	7.3	7.3	7.6	7.7	7.8	7.4	8.1	8.1	8.1	8.6	8.6	8.6	8.7	9.3	10.2	10.5	10.6	10.5	9.7	9.0
3	40.0	40.6	39.8	39.1	40.0	39.8	41.4	42.0	42.8	40.4	44.3	44.1	44.1	46.9	46.9	47.1	47.5	50.6	55.5	57.6	58.0	57.2	52.9	49.4
4	14.5	14.7	14.4	14.2	14.5	14.4	15.0	15.2	15.5	14.6	16.0	16.0	16.0	17.0	17.0	17.1	17.2	18.3	20.1	20.9	21.0	20.7	19.1	17.9
5	17.9	18.2	17.8	17.5	17.9	17.8	18.6	18.8	19.2	18.1	19.8	19.8	19.8	21.0	21.0	21.1	21.3	22.7	24.9	25.8	26.0	25.6	23.7	22.1
6	20.7	21.0	20.6	20.2	20.7	20.6	21.4	21.7	22.2	20.9	22.9	22.8	22.8	24.3	24.3	24.4	24.6	26.2	28.7	29.8	30.0	29.6	27.3	25.5
7	16.5	16.8	16.5	16.2	16.5	16.5	17.1	17.4	17.7	16.7	18.3	18.2	18.2	19.4	19.4	19.5	19.7	20.9	23.0	23.8	24.0	23.7	21.9	20.4
8	53.7	54.6	53.5	52.6	53.7	53.5	55.7	56.5	57.6	54.3	59.5	59.3	59.3	63.1	63.1	63.4	63.9	68.1	74.7	77.4	78.0	76.9	71.1	66.4
9	89.6	91.0	89.1	87.7	89.6	89.1	92.8	94.2	96.0	90.5	99.2	98.8	98.8	105.2	105.2	105.7	106.6	113.5	124.5	129.1	130.0	128.2	118.5	110.7
10	40.0	40.6	39.8	39.1	40.0	39.8	41.4	42.0	42.8	40.4	44.3	44.1	44.1	46.9	46.9	47.1	47.5	50.6	55.5	57.6	58.0	57.2	52.9	49.4
11	57.9	58.8	57.6	56.7	57.9	57.6	60.0	60.8	62.0	58.5	64.1	63.8	63.8	68.0	68.0	68.3	68.9	73.3	80.4	83.4	84.0	82.8	76.6	71.5
12	6.9	7.0	6.9	6.7	6.9	6.9	7.1	7.2	7.4	7.0	7.6	7.6	7.6	8.1	8.1	8.1	8.2	8.7	9.6	9.9	10.0	9.9	9.1	8.5
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	34.5	35.0	34.3	33.7	34.5	34.3	35.7	36.2	36.9	34.8	38.2	38.0	38.0	40.5	40.5	40.6	41.0	43.6	47.9	49.6	50.0	49.3	45.6	42.6
15	50.3	51.1	50.0	49.3	50.3	50.0	52.1	52.9	53.9	50.8	55.7	55.5	55.5	59.1	59.1	59.3	59.8	63.7	69.9	72.5	73.0	72.0	66.6	62.2
16	42.0	42.7	41.8	41.2	42.0	41.8	43.5	44.2	45.0	42.5	46.6	46.3	46.3	49.4	49.4	49.6	50.0	53.2	58.4	60.6	61.0	60.1	55.6	51.9
17	77.9	79.1	77.5	76.3	77.9	77.5	80.7	81.9	83.5	78.7	86.2	85.8	85.8	91.4	91.4	91.8	92.6	98.6	108.2	112.2	113.0	111.4	103.0	96.2
18	25.5	25.9	25.4	25.0	25.5	25.4	26.4	26.8	27.3	25.8	28.2	28.1	28.1	29.9	29.9	30.1	30.3	32.3	35.4	36.7	37.0	36.5	33.7	31.5
19	31.4	31.8	31.2	30.7	31.4	31.2	32.5	33.0	33.6	31.7	34.7	34.6	34.6	36.8	36.8	37.0	37.3	39.7	43.6	45.2	45.5	44.9	41.5	38.7
20	59.1	60.0	58.8	57.9	59.1	58.8	61.2	62.2	63.4	59.7	65.5	65.2	65.2	69.4	69.4	69.7	70.3	74.9	82.2	85.2	85.8	84.6	78.2	73.1
21	77.9	79.1	77.5	76.3	77.9	77.5	80.7	81.9	83.5	78.7	86.2	85.8	85.8	91.4	91.4	91.8	92.6	98.6	108.2	112.2	113.1	111.4	103.0	96.2
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	72.3	73.5	72.0	70.9	72.3	72.0	74.9	76.1	77.5	73.1	80.1	79.8	79.8	85.0	85.0	85.3	86.1	91.6	100.5	104.3	105.0	103.5	95.7	89.4

24	67.2	68.2	66.8	65.8	67.2	66.8	69.6	70.6	72.0	67.9	74.4	74.1	74.1	78.9	78.9	79.2	79.9	85.1	93.4	96.8	97.5	96.1	88.9	83.0
25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	70.3	71.4	69.9	68.8	70.3	69.9	72.8	73.9	75.3	71.0	77.9	77.5	77.5	82.5	82.5	82.9	83.6	89.0	97.7	101.3	102.0	100.6	93.0	86.9
27	11.6	11.8	11.5	11.3	11.6	11.5	12.0	12.2	12.4	11.7	12.8	12.8	12.8	13.6	13.6	13.7	13.8	14.7	16.1	16.7	16.8	16.6	15.3	14.3
28	75.8	77.0	75.4	74.2	75.8	75.4	78.5	79.7	81.2	76.6	84.0	83.6	83.6	89.0	89.0	89.4	90.2	96.0	105.3	109.2	110.0	108.4	100.3	93.7
29	31.0	31.5	30.8	30.4	31.0	30.8	32.1	32.6	33.2	31.3	34.3	34.2	34.2	36.4	36.4	36.6	36.9	39.3	43.1	44.7	45.0	44.4	41.0	38.3
30	48.9	49.7	48.7	47.9	48.9	48.7	50.7	51.4	52.4	49.4	54.2	53.9	53.9	57.5	57.5	57.7	58.2	62.0	68.0	70.5	71.0	70.0	64.7	60.5
31	48.2	49.0	48.0	47.2	48.2	48.0	50.0	50.7	51.7	48.7	53.4	53.2	53.2	56.6	56.6	56.9	57.4	61.1	67.0	69.5	70.0	69.0	63.8	59.6
32	44.8	45.5	44.6	43.9	44.8	44.6	46.4	47.1	48.0	45.2	49.6	49.4	49.4	52.6	52.6	52.8	53.3	56.7	62.2	64.5	65.0	64.1	59.3	55.4
33	57.2	58.1	56.9	56.0	57.2	56.9	59.2	60.1	61.3	57.8	63.3	63.1	63.1	67.2	67.2	67.5	68.0	72.4	79.5	82.4	83.0	81.8	75.7	70.7
34	88.9	90.3	88.4	87.1	88.9	88.4	92.1	93.4	95.3	89.8	98.5	98.0	98.0	104.4	104.4	104.8	105.8	112.6	123.5	128.1	129.4	127.2	117.6	109.9
35	107.5	109.1	106.9	105.3	107.5	106.9	111.3	113.0	115.2	108.6	119.1	118.5	118.5	126.2	126.2	126.8	127.9	136.2	149.4	154.9	156.0	153.8	142.2	132.8
36	68.0	69.1	67.7	66.6	68.0	67.7	70.5	71.5	72.9	68.7	75.3	75.0	75.0	79.9	79.9	80.2	80.9	86.1	94.5	98.0	98.7	97.3	90.0	84.1
37	55.1	56.0	54.8	54.0	55.1	54.8	57.1	58.0	59.1	55.7	61.1	60.8	60.8	64.7	64.7	65.0	65.6	69.8	76.6	79.4	80.0	78.9	72.9	68.1
38	38.2	38.8	38.0	37.5	38.2	38.0	39.6	40.2	41.0	38.6	42.4	42.2	42.2	44.9	44.9	45.1	45.5	48.4	53.1	55.1	55.5	54.7	50.6	47.3
39	59.9	60.9	59.6	58.7	59.9	59.6	62.1	63.0	64.3	60.6	66.4	66.1	66.1	70.4	70.4	70.7	71.3	75.9	83.3	86.4	87.0	85.8	79.3	74.1
40	78.6	79.8	78.1	76.9	78.6	78.1	81.4	82.6	84.2	79.4	87.0	86.6	86.6	92.2	92.2	92.7	93.5	99.5	109.2	113.2	114.0	112.4	103.9	97.1
41	55.1	56.0	54.8	54.0	55.1	54.8	57.1	58.0	59.1	55.7	61.1	60.8	60.8	64.7	64.7	65.0	65.6	69.8	76.6	79.4	80.0	78.9	72.9	68.1
42	37.2	37.8	37.0	36.4	37.2	37.0	38.5	39.1	39.9	37.6	41.2	41.0	41.0	43.7	43.7	43.9	44.3	47.1	51.7	53.6	54.0	53.2	49.2	46.0
43	68.9	70.0	68.6	67.5	68.9	68.6	71.4	72.4	73.9	69.6	76.3	76.0	76.0	80.9	80.9	81.3	82.0	87.3	95.8	99.3	100.0	98.6	91.2	85.2
44	65.5	66.5	65.1	64.1	65.5	65.1	67.8	68.8	70.2	66.1	72.5	72.2	72.2	76.9	76.9	77.2	77.9	82.9	91.0	94.3	95.0	93.7	86.6	80.9
45	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
46	43.7	44.4	43.5	42.8	43.7	43.5	45.3	45.9	46.8	44.1	48.4	48.2	48.2	51.3	51.3	51.5	52.0	55.3	60.7	63.0	63.4	62.5	57.8	54.0
47	26.9	27.3	26.7	26.3	26.9	26.7	27.8	28.3	28.8	27.1	29.8	29.6	29.6	31.6	31.6	31.7	32.0	34.0	37.3	38.7	39.0	38.4	35.6	33.2
48	66.8	67.9	66.5	65.5	66.8	66.5	69.2	70.3	71.6	67.5	74.0	73.7	73.7	78.5	78.5	78.8	79.5	84.7	92.9	96.3	97.0	95.6	88.4	82.6
49	55.8	56.7	55.5	54.7	55.8	55.5	57.8	58.7	59.8	56.4	61.8	61.5	61.5	65.5	65.5	65.8	66.4	70.7	77.6	80.4	81.0	79.9	73.8	69.0
50	20.0	20.3	19.9	19.6	20.0	19.9	20.7	21.0	21.4	20.2	22.1	22.0	22.0	23.5	23.5	23.6	23.8	25.3	27.8	28.8	29.0	28.6	26.4	24.7
51	21.3	21.6	21.2	20.9	21.3	21.2	22.1	22.4	22.8	21.5	23.6	23.5	23.5	25.0	25.0	25.1	25.3	27.0	29.6	30.7	30.9	30.5	28.2	26.3
52	20.7	21.0	20.6	20.2	20.7	20.6	21.4	21.7	22.2	20.9	22.9	22.8	22.8	24.3	24.3	24.4	24.6	26.2	28.7	29.8	30.0	29.6	27.3	25.5
53	19.2	19.5	19.1	18.8	19.2	19.1	19.8	20.1	20.5	19.4	21.2	21.1	21.1	22.5	22.5	22.6	22.8	24.3	26.6	27.6	27.8	27.4	25.3	23.7
54	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
55	76.5	77.7	76.1	74.9	76.5	76.1	79.2	80.4	82.0	77.3	84.7	84.3	84.3	89.8	89.8	90.2	91.0	96.9	106.3	110.2	111.0	109.4	101.2	94.5
56	14.5	14.7	14.4	14.2	14.5	14.4	15.0	15.2	15.5	14.6	16.0	16.0	16.0	17.0	17.0	17.1	17.2	18.3	20.1	20.9	21.0	20.7	19.1	17.9
57	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.1	1.2	1.2	1.2	1.1	1.0
58	48.2	49.0	48.0	47.2	48.2	48.0	50.0	50.7	51.7	48.7	53.4	53.2	53.2	56.6	56.6	56.9	57.4	61.1	67.0	69.5	70.0	69.0	63.8	59.6
59	20.7	21.0	20.6	20.2	20.7	20.6	21.4	21.7	22.2	20.9	22.9	22.8	22.8	24.3	24.3	24.4	24.6	26.2	28.7	29.8	30.0	29.6	27.3	25.5
60	44.8	45.5	44.6	43.9	44.8	44.6	46.4	47.1	48.0	45.2	49.6	49.4	49.4	52.6	52.6	52.8	53.3	56.7	62.2	64.5	65.0	64.1	59.3	55.4
61	30.3	30.8	30.2	29.7	30.3	30.2	31.4	31.9	32.5	30.6	33.6	33.4	33.4	35.6	35.6	35.8	36.1	38.4	42.1	43.7	44.0	43.4	40.1	37.5
62	27.6	28.0	27.4	27.0	27.6	27.4	28.6	29.0	29.5	27.8	30.5	30.4	30.4	32.4	32.4	32.5	32.8	34.9	38.3	39.7	40.0	39.4	36.5	34.1

63	3.2	3.2	3.1	3.1	3.2	3.1	3.3	3.3	3.4	3.2	3.5	3.5	3.5	3.7	3.7	3.7	3.8	4.0	4.4	4.5	4.6	4.5	4.2	3.9
64	34.5	35.0	34.3	33.7	34.5	34.3	35.7	36.2	36.9	34.8	38.2	38.0	38.0	40.5	40.5	40.6	41.0	43.6	47.9	49.6	50.0	49.3	45.6	42.6
65	9.1	9.2	9.0	8.9	9.1	9.0	9.4	9.6	9.7	9.2	10.1	10.0	10.0	10.7	10.7	10.7	10.8	11.5	12.6	13.1	13.2	13.0	12.0	11.2
66	26.2	26.6	26.0	25.6	26.2	26.0	27.1	27.5	28.1	26.5	29.0	28.9	28.9	30.7	30.7	30.9	31.2	33.2	36.4	37.7	38.0	37.5	34.6	32.4
67	25.4	25.7	25.2	24.8	25.4	25.2	26.3	26.7	27.2	25.6	28.1	28.0	28.0	29.8	29.8	29.9	30.2	32.1	35.2	36.5	36.8	36.3	33.5	31.3
68	13.8	14.0	13.7	13.5	13.8	13.7	14.3	14.5	14.8	13.9	15.3	15.2	15.2	16.2	16.2	16.3	16.4	17.5	19.2	19.9	20.0	19.7	18.2	17.0
69	22.7	23.1	22.6	22.3	22.7	22.6	23.6	23.9	24.4	23.0	25.2	25.1	25.1	26.7	26.7	26.8	27.1	28.8	31.6	32.8	33.0	32.5	30.1	28.1
70	13.8	14.0	13.7	13.5	13.8	13.7	14.3	14.5	14.8	13.9	15.3	15.2	15.2	16.2	16.2	16.3	16.4	17.5	19.2	19.9	20.0	19.7	18.2	17.0
71	10.7	10.8	10.6	10.5	10.7	10.6	11.1	11.2	11.4	10.8	11.8	11.8	11.8	12.5	12.5	12.6	12.7	13.5	14.8	15.4	15.5	15.3	14.1	13.2
72	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
73	13.6	13.8	13.5	13.3	13.6	13.5	14.1	14.3	14.5	13.7	15.0	15.0	15.0	15.9	15.9	16.0	16.1	17.2	18.9	19.6	19.7	19.4	18.0	16.8
74	17.2	17.5	17.1	16.9	17.2	17.1	17.8	18.1	18.5	17.4	19.1	19.0	19.0	20.2	20.2	20.3	20.5	21.8	23.9	24.8	25.0	24.6	22.8	21.3
75	34.5	35.0	34.3	33.7	34.5	34.3	35.7	36.2	36.9	34.8	38.2	38.0	38.0	40.5	40.5	40.6	41.0	43.6	47.9	49.6	50.0	49.3	45.6	42.6
76	44.8	45.5	44.6	43.9	44.8	44.6	46.4	47.1	48.0	45.2	49.6	49.4	49.4	52.6	52.6	52.8	53.3	56.7	62.2	64.5	65.0	64.1	59.3	55.4
77	30.3	30.8	30.2	29.7	30.3	30.2	31.4	31.9	32.5	30.6	33.6	33.4	33.4	35.6	35.6	35.8	36.1	38.4	42.1	43.7	44.0	43.4	40.1	37.5
78	34.5	35.0	34.3	33.7	34.5	34.3	35.7	36.2	36.9	34.8	38.2	38.0	38.0	40.5	40.5	40.6	41.0	43.6	47.9	49.6	50.0	49.3	45.6	42.6
79	19.3	19.6	19.2	18.9	19.3	19.2	20.0	20.3	20.7	19.5	21.4	21.3	21.3	22.7	22.7	22.8	23.0	24.4	26.8	27.8	28.0	27.6	25.5	23.8
80	23.8	24.2	23.7	23.4	23.8	23.7	24.7	25.1	25.6	24.1	26.4	26.3	26.3	28.0	28.0	28.1	28.4	30.2	33.1	34.4	34.6	34.1	31.5	29.5
81	18.9	19.2	18.9	18.6	18.9	18.9	19.6	19.9	20.3	19.1	21.0	20.9	20.9	22.3	22.3	22.3	22.5	24.0	26.3	27.3	27.5	27.1	25.1	23.4
82	77.9	79.1	77.5	76.3	77.9	77.5	80.7	81.9	83.5	78.7	86.2	85.8	85.8	91.4	91.4	91.8	92.6	98.6	108.2	112.2	113.0	111.4	103.0	96.2
83	50.3	51.1	50.0	49.3	50.3	50.0	52.1	52.9	53.9	50.8	55.7	55.5	55.5	59.1	59.1	59.3	59.8	63.7	69.9	72.5	73.0	72.0	66.6	62.2
84	15.8	16.1	15.8	15.5	15.8	15.8	16.4	16.7	17.0	16.0	17.6	17.5	17.5	18.6	18.6	18.7	18.9	20.1	22.0	22.8	23.0	22.7	21.0	19.6
85	40.0	40.6	39.8	39.1	40.0	39.8	41.4	42.0	42.8	40.4	44.3	44.1	44.1	46.9	46.9	47.1	47.5	50.6	55.5	57.6	58.0	57.2	52.9	49.4
86	15.4	15.7	15.4	15.1	15.4	15.4	16.0	16.2	16.5	15.6	17.1	17.0	17.0	18.1	18.1	18.2	18.4	19.6	21.5	22.2	22.4	22.1	20.4	19.1
87	28.1	28.5	28.0	27.5	28.1	28.0	29.1	29.6	30.1	28.4	31.1	31.0	31.0	33.0	33.0	33.2	33.4	35.6	39.1	40.5	40.8	40.2	37.2	34.7
88	16.8	17.1	16.7	16.5	16.8	16.7	17.4	17.7	18.0	17.0	18.6	18.5	18.5	19.7	19.7	19.8	20.0	21.3	23.4	24.2	24.4	24.1	22.2	20.8
89	29.6	30.1	29.5	29.0	29.6	29.5	30.7	31.1	31.8	29.9	32.8	32.7	32.7	34.8	34.8	34.9	35.3	37.5	41.2	42.7	43.0	42.4	39.2	36.6
90	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
91	9.6	9.8	9.6	9.4	9.6	9.6	10.0	10.1	10.3	9.7	10.7	10.6	10.6	11.3	11.3	11.4	11.5	12.2	13.4	13.9	14.0	13.8	12.8	11.9
92	4.8	4.9	4.8	4.7	4.8	4.8	5.0	5.1	5.2	4.9	5.3	5.3	5.3	5.7	5.7	5.7	5.7	6.1	6.7	7.0	7.0	6.9	6.4	6.0
93	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
94	23.3	23.6	23.2	22.8	23.3	23.2	24.1	24.5	25.0	23.5	25.8	25.7	25.7	27.4	27.4	27.5	27.7	29.5	32.4	33.6	33.8	33.3	30.8	28.8
95	20.7	21.0	20.6	20.2	20.7	20.6	21.4	21.7	22.2	20.9	22.9	22.8	22.8	24.3	24.3	24.4	24.6	26.2	28.7	29.8	30.0	29.6	27.3	25.5
96	17.1	17.4	17.0	16.7	17.1	17.0	17.7	18.0	18.3	17.3	18.9	18.8	18.8	20.1	20.1	20.2	20.3	21.6	23.7	24.6	24.8	24.4	22.6	21.1
97	21.3	21.6	21.2	20.9	21.3	21.2	22.1	22.4	22.8	21.5	23.6	23.5	23.5	25.0	25.0	25.1	25.3	27.0	29.6	30.7	30.9	30.5	28.2	26.3
98	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
99	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
100	26.2	26.6	26.0	25.6	26.2	26.0	27.1	27.5	28.1	26.5	29.0	28.9	28.9	30.7	30.7	30.9	31.2	33.2	36.4	37.7	38.0	37.5	34.6	32.4
101	46.6	47.4	46.4	45.7	46.6	46.4	48.3	49.0	50.0	47.1	51.7	51.4	51.4	54.8	54.8	55.0	55.5	59.1	64.8	67.2	67.7	66.7	61.7	57.7

102	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
103	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
104	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
105	30.9	31.3	30.7	30.2	30.9	30.7	32.0	32.5	33.1	31.2	34.2	34.0	34.0	36.3	36.3	36.4	36.7	39.1	42.9	44.5	44.8	44.2	40.8	38.2
106	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
107	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
108	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
109	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
110	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
111	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
112	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
113	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
114	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
115	8.6	8.7	8.6	8.4	8.6	8.6	8.9	9.1	9.2	8.7	9.5	9.5	9.5	10.1	10.1	10.2	10.2	10.9	12.0	12.4	12.5	12.3	11.4	10.6
116	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
117	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
118	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
119	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
120	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
121	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
122	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
123	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
124	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
125	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
126	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
127	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
128	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
129	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
130	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
131	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
132	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
133	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
134	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
135	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
136	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
137	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
138	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
139	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
140	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

141	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
142	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
144	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
145	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
146	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
147	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
148	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
149	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
150	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
151	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
152	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
153	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
154	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
155	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
156	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
157	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
158	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
159	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
160	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
161	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
162	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
163	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
164	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
165	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
166	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

B.3: 165x165 Bus impedance matrix ([R]+j[X]) elements for selected rows and columns

Elements for 165 rows and first 14 columns of R matrix

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	[0.000412	-0.000694	-0.000641	-0.000649	-0.000649	-0.000649	-0.000652	-0.000654	-0.000675	-0.000652	-0.00065	-0.00065	-0.000694	-0.000694
2	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.001497	0.001497
3	-0.000641	0.000651	0.001555	0.001412	0.001412	0.001412	0.001368	0.00134	0.000981	0.001376	0.0014	0.001405	0.000651	0.000651
4	-0.000649	0.000785	0.001412	0.003339	0.003339	0.003339	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785
5	-0.000649	0.000785	0.001412	0.003339	0.013489	0.013489	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785
6	-0.000649	0.000785	0.001412	0.003339	0.013489	0.038719	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785
7	-0.000652	0.000826	0.001368	0.00277	0.00277	0.00277	0.005239	0.00274	0.001745	0.002755	0.003456	0.003155	0.000826	0.000826
8	-0.000654	0.000852	0.00134	0.00241	0.00241	0.00241	0.00274	0.002949	0.001859	0.00268	0.002502	0.002462	0.000852	0.000852
9	-0.000675	0.001188	0.000981	0.001565	0.001565	0.001565	0.001745	0.001859	0.003319	0.001712	0.001615	0.001593	0.001188	0.001188
10	-0.000652	0.000818	0.001376	0.002874	0.002874	0.002874	0.002755	0.00268	0.001712	0.003357	0.002841	0.002856	0.000818	0.000818
11	-0.00065	0.000796	0.0014	0.003181	0.003181	0.003181	0.003456	0.002502	0.001615	0.002841	0.004546	0.003949	0.000796	0.000796
12	-0.00065	0.000791	0.001405	0.00325	0.00325	0.00325	0.003155	0.002462	0.001593	0.002856	0.003949	0.004785	0.000791	0.000791
13	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.014753	0.013588
14	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.013588	0.020397
15	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.008054	0.008663
16	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.008637	0.009898
17	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.010857	0.014607
18	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
19	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006656	0.007135
20	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006625	0.007101
21	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
22	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007107
23	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007107
24	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006621	0.007097
25	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
26	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
27	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006625	0.007101
28	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006639	0.007116
29	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
30	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.00663	0.007106

31	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006621	0.007097
32	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006621	0.007096
33	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006614	0.007089
34	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006616	0.007091
35	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
36	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006615	0.00709
37	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007086
38	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006606	0.00708
39	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006606	0.00708
40	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006606	0.00708
41	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006597	0.00707
42	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006603	0.007076
43	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006625	0.007101
44	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006616	0.007091
45	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
46	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
47	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
48	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
49	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
50	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
51	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
52	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
53	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
54	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
55	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
56	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
57	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
58	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
59	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
60	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
61	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
62	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
63	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
64	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
65	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
66	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
67	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
68	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
69	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086

70	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
71	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
72	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
73	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
74	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007085
75	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007085
76	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007085
77	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
78	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
79	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
80	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006608	0.007083
81	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
82	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
83	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
84	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
85	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
86	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
87	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
88	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
89	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
90	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006607	0.007081
91	-0.000667	0.001059	0.001119	0.00189	0.00189	0.00189	0.002128	0.002278	0.002758	0.002084	0.001956	0.001927	0.001059	0.001059
92	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
93	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007086
94	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
95	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087
96	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.001996	0.002042
97	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.001996	0.002042
98	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006582	0.007054
99	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
100	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007108
101	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006632	0.007109
102	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006673	0.007153
103	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006646	0.007123
104	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006654	0.007133
105	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006673	0.007153
106	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.00666	0.007139
107	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007086
108	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007084

109	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
110	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006635	0.007112
111	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006608	0.007082
112	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006608	0.007082
113	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006608	0.007082
114	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006673	0.007153
115	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
116	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
117	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
118	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
119	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006656	0.007135
120	-0.000649	0.000785	0.001412	0.003339	0.003339	0.003339	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785
121	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
122	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006603	0.007076
123	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006659	0.007138
124	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
125	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006656	0.007135
126	-0.000649	0.000785	0.001412	0.003339	0.003339	0.003339	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785
127	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006603	0.007076
128	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.014753	0.013588
129	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.008637	0.009898
130	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006597	0.00707
131	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006597	0.00707
132	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
133	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
134	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
135	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
136	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
137	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
138	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
139	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
140	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
141	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006561	0.00703
142	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
143	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
144	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
145	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
146	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007086
147	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006612	0.007087

148	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006611	0.007085
149	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.001996	0.002042
150	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
151	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
152	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
153	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
154	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006602	0.007075
155	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007108
156	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007108
157	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007108
158	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006631	0.007108
159	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006673	0.007153
160	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006608	0.007082
161	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006656	0.007135
162	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
163	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006609	0.007083
164	-0.000694	0.001497	0.000651	0.000785	0.000785	0.000785	0.000826	0.000852	0.001188	0.000818	0.000796	0.000791	0.006656	0.007135
165	-0.000649	0.000785	0.001412	0.003339	0.003339	0.003339	0.00277	0.00241	0.001565	0.002874	0.003181	0.00325	0.000785	0.000785

Elements for 165 rows and first 14 columns of X matrix

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	[0.016096	0.004237	0.004914	0.004807	0.004807	0.004807	0.004774	0.004753	0.004485	0.00478	0.004798	0.004802	0.004237	0.004237
2	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.025754	0.025754
3	0.004914	0.021318	0.024566	0.024052	0.024052	0.024052	0.023894	0.023793	0.022506	0.023923	0.024008	0.024027	0.021318	0.021318
4	0.004807	0.02202	0.024052	0.031975	0.031975	0.031975	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202
5	0.004807	0.02202	0.024052	0.031975	0.073275	0.073275	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202
6	0.004807	0.02202	0.024052	0.031975	0.073275	0.175935	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202
7	0.004774	0.022237	0.023894	0.029684	0.029684	0.029684	0.039761	0.029609	0.025775	0.029647	0.032483	0.031259	0.022237	0.022237
8	0.004753	0.022374	0.023793	0.028237	0.028237	0.028237	0.029609	0.030476	0.026263	0.029357	0.028618	0.028451	0.022374	0.022374
9	0.004485	0.024131	0.022506	0.025004	0.025004	0.025004	0.025775	0.026263	0.032518	0.025634	0.025218	0.025125	0.024131	0.024131
10	0.00478	0.022197	0.023923	0.030106	0.030106	0.030106	0.029647	0.029357	0.025634	0.032091	0.029978	0.030034	0.022197	0.022197
11	0.004798	0.02208	0.024008	0.031338	0.031338	0.031338	0.032483	0.028618	0.025218	0.029978	0.036901	0.034467	0.02208	0.02208
12	0.004802	0.022054	0.024027	0.031617	0.031617	0.031617	0.031259	0.028451	0.025125	0.030034	0.034467	0.037867	0.022054	0.022054
13	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.090194	0.086428
14	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.086428	0.115201
15	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.068543	0.072513
16	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.070425	0.077007
17	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.077603	0.094138
18	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
19	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058762	0.061824
20	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058286	0.061304
21	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
22	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058365	0.061391
23	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058365	0.061391
24	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05822	0.061232
25	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
26	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878

27	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058252	0.061268
28	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058506	0.061545
29	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058083	0.061083
30	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058365	0.061391
31	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05822	0.061232
32	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058159	0.061165
33	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058047	0.061044
34	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058056	0.061053
35	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058054	0.061051
36	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058127	0.06113
37	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058059	0.061056
38	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058078	0.061077
39	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058078	0.061077
40	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058078	0.061077
41	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058112	0.061114
42	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05809	0.061091
43	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05843	0.061462
44	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058041	0.061037
45	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
46	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
47	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
48	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
49	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
50	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
51	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
52	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
53	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
54	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
55	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
56	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609
57	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609

58	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060608
59	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057648	0.060608
60	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057647	0.060607
61	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057646	0.060605
62	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057646	0.060605
63	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057646	0.060606
64	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057647	0.060606
65	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057647	0.060606
66	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057647	0.060607
67	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057648	0.060608
68	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060608
69	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060608
70	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057647	0.060607
71	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05765	0.060609
72	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05765	0.060609
73	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057645	0.060604
74	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057633	0.060591
75	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057633	0.060591
76	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057633	0.060591
77	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057642	0.060601
78	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057619	0.060575
79	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057618	0.060575
80	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057615	0.060572
81	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057607	0.060563
82	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057607	0.060563
83	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057605	0.06056
84	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057602	0.060557
85	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057602	0.060557
86	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057601	0.060556
87	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057601	0.060556
88	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057601	0.060556

89	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057606	0.060562
90	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.0576	0.060555
91	0.004588	0.023455	0.023001	0.026248	0.026248	0.026248	0.02725	0.027883	0.030112	0.027065	0.026526	0.026404	0.023455	0.023455
92	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
93	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058059	0.061056
94	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
95	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057646	0.060605
96	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.034184	0.034967
97	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.034184	0.034967
98	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.056491	0.059343
99	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421
100	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057852	0.06083
101	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057954	0.060942
102	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057987	0.060978
103	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057895	0.060877
104	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057776	0.060747
105	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057987	0.060978
106	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058022	0.061016
107	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057652	0.060611
108	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057616	0.060572
109	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05765	0.06061
110	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057974	0.060964
111	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057589	0.060543
112	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057598	0.060552
113	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057599	0.060554
114	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057987	0.060978
115	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
116	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057618	0.060575
117	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
118	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
119	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058762	0.061824

120	0.004807	0.02202	0.024052	0.031975	0.031975	0.031975	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202
121	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
122	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05809	0.061091
123	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058811	0.061878
124	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057618	0.060575
125	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058762	0.061824
126	0.004807	0.02202	0.024052	0.031975	0.031975	0.031975	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202
127	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.05809	0.061091
128	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.090194	0.086428
129	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.070425	0.077007
130	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058112	0.061114
131	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058112	0.061114
132	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
133	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
134	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
135	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
136	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
137	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
138	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
139	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
140	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
141	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057728	0.060694
142	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609
143	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609
144	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609
145	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060609
146	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057649	0.060608
147	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057646	0.060605
148	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057633	0.060591
149	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.034184	0.034967
150	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421

151	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421
152	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421
153	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421
154	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057477	0.060421
155	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057852	0.06083
156	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057852	0.06083
157	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057852	0.06083
158	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057852	0.06083
159	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057987	0.060978
160	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057599	0.060554
161	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058762	0.061824
162	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057618	0.060575
163	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.057618	0.060575
164	0.004237	0.025754	0.021318	0.02202	0.02202	0.02202	0.022237	0.022374	0.024131	0.022197	0.02208	0.022054	0.058762	0.061824
165	0.004807	0.02202	0.024052	0.031975	0.031975	0.031975	0.029684	0.028237	0.025004	0.030106	0.031338	0.031617	0.02202	0.02202

B.4: Units scheduled for BPS by classical Lagrange method under loading scenario -2 of Table-5.9

Units:

H	u1	u2	u3	u4	u5	u6	u7	u8	u9	u10	u11	u12	u13	u14	u15	u16	u17	u18	u19	u20	u21	u22	u23	u24
1	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
2	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
3	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
4	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
5	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
6	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
7	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
8	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
9	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
10	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
11	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
12	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
13	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
14	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
15	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
16	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
17	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
18	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
19	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
20	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
21	1	0	0	0	1	1	0	1	1	1	1	0	1	0	1	1	1	1	1	1	1	1	1	1
22	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
23	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
24	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1

H	u25	u26	u27	u28	u29	u30	u31	u32	u33	u34	u35	u36	u37	u38	u39	u40	u41	u42	u43	u44	u45	u46	u47	u48
1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
2	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
3	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
4	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
5	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
6	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
7	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
8	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
9	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
10	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
11	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
12	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
13	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
14	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
15	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
16	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
17	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
18	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
19	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
20	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
21	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
22	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
23	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
24	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1

H	u49	u50	u51	u52	u53	u54	u55	u56	u57	u58	u59	u60	u61	u62	u63	u64	u65	u66	u67	u68	u69	u70	u71	u72
1	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
4	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
6	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
7	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
8	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
9	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
11	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
16	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
17	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	0	0	0	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
22	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
23	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
24	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

H	u73	u74	u75	u76	u77	u78	u79	u80	u81	u82	u83	u84	u85	u86	u87	u88	u89	u90	u91	u92	u93
1	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
2	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
3	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
4	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
5	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
6	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
7	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
8	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
9	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
10	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
11	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
12	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
13	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
14	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
15	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
16	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
17	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
18	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
19	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
20	1	1	1	0	1	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1
21	1	1	1	0	1	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1
22	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
23	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
24	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1

Units scheduled for BPS by Proposed method under loading scenario-2 of Table 5.9

	Units:																							
H	u1	u2	u3	u4	u5	u6	u7	u8	u9	u10	u11	u12	u13	u14	u15	u16	u17	u18	u19	u20	u21	u22	u23	u24
1	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
2	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
3	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
4	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
5	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
6	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
7	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
8	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
9	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
10	1	0	0	0	0	0	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
11	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
12	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
13	1	0	0	0	0	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
14	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
15	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
16	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
17	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
18	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
19	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
20	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
21	1	0	0	0	1	1	0	1	1	1	1	0	1	0	1	1	1	1	1	1	1	1	1	1
22	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
23	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1
24	1	0	0	0	1	1	0	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1

H	u25	u26	u27	u28	u29	u30	u31	u32	u33	u34	u35	u36	u37	u38	u39	u40	u41	u42	u43	u44	u45	u46	u47	u48
1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
2	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
3	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
4	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
5	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
6	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
7	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
8	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
9	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
10	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
11	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
12	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
13	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
14	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
15	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
16	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
17	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1
18	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
19	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
20	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
21	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
22	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
23	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0	1	0	1
24	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1

H	u49	u50	u51	u52	u53	u54	u55	u56	u57	u58	u59	u60	u61	u62	u63	u64	u65	u66	u67	u68	u69	u70	u71	u72
1	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
4	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
6	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
7	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
8	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
9	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	0	0	0	0	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
11	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
16	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
17	0	0	0	0	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	0	0	0	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
22	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
23	0	1	1	1	1	1	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

H	u73	u74	u75	u76	u77	u78	u79	u80	u81	u82	u83	u84	u85	u86	u87	u88	u89	u90	u91	u92	u93
1	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
2	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
3	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
4	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
5	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
6	1	1	1	0	0	1	0	0	0	0	0	0	0	1	1	1	1	1	0	0	1
7	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
8	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
9	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
10	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
11	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
12	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
13	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
14	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
15	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
16	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
17	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1
18	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
19	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
20	1	1	1	0	1	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1
21	1	1	1	0	1	1	1	0	0	0	0	0	1	1	1	1	1	1	1	1	1
22	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
23	1	1	1	0	1	1	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
24	1	1	1	0	0	1	0	0	0	0	0	0	1	1	1	1	1	1	0	0	1

B.5: Units scheduled (U_i =1 means ON and U_i = 0 means OFF) in BPS system by the proposed (P) and the classical Lagrange (C) methods for a peak hour and an off-peak hour under two representative loading patterns

Gen. Sl. No.	Bus No.	Location	cost coeff (b); a and c as in Table B.1.4	Peak hour (9 pm)				Off-peak hour(11am)				Fuel Type
				Loading pattern-1		Loading pattern-2		Loading pattern-1		Loading pattern-2		
				C	P	C	P	C	P	C	P	
				Ui	Ui	Ui	Ui	Ui	Ui	Ui	Ui	
1	1	Kaptai	0	1	1	1	1	1	1	1	1	Hydro
2	3	Hathazari	111	0	0	0	0	0	0	0	0	Oil
3	4	Madanhat	118	0	0	0	0	0	0	0	0	Oil
4	6	Dohazari	111	0	0	0	0	0	0	0	0	Oil
5	8	Halishahar	40	1	1	1	1	1	0	1	1	Gas
6	10	Baraulia	36	1	1	1	1	1	1	1	1	Gas
7	12	Julda	110	0	0	0	0	0	0	0	0	Oil
8	14	Feni-1	36	1	1	1	1	1	1	1	1	Gas
9	129	Feni-2	36	1	1	1	1	1	1	1	1	Gas
10	17	Comilla(s)-1	36	1	1	1	1	1	1	1	1	Gas
11	130	Comilla(s)-2	36	1	1	1	1	1	1	1	1	Gas
12	28	Shyampur	134	0	0	0	0	0	0	0	0	Oil
13	29	Madanganj	113	0	0	0	1	0	0	0	0	Oil
14	30	Hasnabad	116	0	0	0	0	0	0	0	0	Oil
15	36	Uttara	36	1	1	1	1	1	1	1	1	Gas
16	38	Tongi	52	1	1	1	1	1	1	1	1	Gas
17	41	Tangail	36	1	1	1	1	1	1	1	1	Gas
18	42	Ghorasal-1	44	1	1	1	1	1	1	1	1	Gas
19	131	Ghorasal-2	44	1	1	1	1	1	1	1	1	Gas
20	132	Ghorasal-3	44	1	1	1	1	1	1	1	1	Gas
21	44	Bhulta	36	1	1	1	1	1	1	1	1	Gas
22	46	Ashuganj-1	44	1	1	1	1	1	1	1	1	Gas
23	133	Ashuganj-2	44	1	1	1	1	1	1	1	1	Gas

24	134	Ashuganj-3	44	1	1	1	1	1	1	1	1	Gas
25	48	Mymenshingh	32	1	1	1	1	1	1	1	1	Gas
26	51	Shahjibazar-1	52	1	1	1	1	1	1	1	1	Gas
27	135	Shahjibazar-2	52	1	1	1	1	1	1	1	1	Gas
28	136	Shahjibazar-3	52	1	1	1	1	1	1	1	1	Gas
29	137	Shahjibazar-4	52	1	1	1	1	1	1	1	1	Gas
30	54	Fenchuganj-1	40	1	1	1	1	1	1	1	1	Gas
31	138	Fenchuganj-2	40	1	1	1	1	1	1	1	1	Gas
32	139	Fenchuganj-3	40	1	1	1	1	1	1	1	1	Gas
33	140	Fenchuganj-4	40	1	1	1	1	1	1	1	1	Gas
34	55	Sylhet-1	44	1	1	1	1	1	1	1	1	Gas
35	141	Sylhet-2	44	1	1	1	1	1	1	1	1	Gas
36	142	Sylhet-3	44	1	1	1	1	1	1	1	1	Gas
37	57	Khulna C-1	152	0	0	0	0	0	0	0	0	Oil
38	143	Khulna C-2	152	0	0	0	0	0	0	0	0	Oil
39	144	Khulna C-3	152	0	0	0	0	0	0	0	0	Oil
40	145	Khulna C-4	152	0	0	0	0	0	0	0	0	Oil
41	146	Khulna C-5	152	0	0	0	0	0	0	0	0	Oil
42	59	Noapara-1	116	0	1	0	1	0	0	0	0	Oil
43	147	Noapara-2	116	0	1	0	1	0	0	0	0	Oil
44	63	Bheramara-1	167	0	0	0	0	0	0	0	0	Oil
45	148	Bheramara-2	167	0	0	0	0	0	0	0	0	Oil
46	64	Faridpur	117	0	0	0	1	0	0	0	0	Oil
47	67	Barisal	267	0	0	0	0	0	0	0	0	Oil
48	71	Bhola (nearest grid bus is Patuakhali)	48	1	1	1	1	1	1	1	1	Gas
49	74	Ishurdi	124	0	0	0	0	0	0	0	0	Oil
50	76	Rajshahi-1	115	0	0	0	1	0	0	0	0	Oil
51	149	Rajshahi-2	115	0	0	0	1	0	0	0	0	Oil
52	77	Chapai Nawabganj	113	0	1	0	1	0	0	0	0	Oil
53	79	Shahjadpur	36	1	1	1	1	1	1	1	1	Gas

54	82	Bogra	40	1	1	1	1	1	1	1	1	Gas
55	85	Rangpur	233	0	0	0	0	0	0	0	0	Oil
56	87	Saidpur	229	0	0	0	0	0	0	0	0	Oil
57	89	Thakurgaon	139	0	0	0	0	0	0	0	0	Oil
58	97	Raozan-1	44	1	1	1	1	1	1	1	1	Gas
59	150	Raozan-2	44	1	1	1	1	1	1	1	1	Gas
60	100	Ashuganj230-1	40	1	1	1	1	1	1	1	1	Gas
61	151	Ashuganj230-2	40	1	1	1	1	1	1	1	1	Gas
62	152	Ashuganj230-3	40	1	1	1	1	1	1	1	1	Gas
63	153	Ashuganj230-4	40	1	1	1	1	1	1	1	1	Gas
64	154	Ashuganj230-5	40	1	1	1	1	1	1	1	1	Gas
65	155	Ashuganj230-6	40	1	1	1	1	1	1	1	1	Gas
66	101	Ghorasal230-1	44	1	1	1	1	1	1	1	1	Gas
67	156	Ghorasal230-2	44	1	1	1	1	1	1	1	1	Gas
68	157	Ghorasal230-3	44	1	1	1	1	1	1	1	1	Gas
69	158	Ghorasal230-4	44	1	1	1	1	1	1	1	1	Gas
70	159	Ghorasal230-Rental	44	1	1	1	1	1	1	1	1	Gas
71	103	Haripur230-1	32	1	1	1	1	1	1	1	1	Gas
72	160	Haripur230-2	32	1	1	1	1	1	1	1	1	Gas
73	105	Meghnaghat230	32	1	1	1	1	1	1	1	1	Gas
74	114	Barapukuria-1	59	1	1	1	1	0	1	1	1	Coal
75	161	Barapukuria-2	59	1	1	1	1	0	1	1	1	Coal
76	116	Haripur	118	0	0	0	0	0	0	0	0	Oil
77	117	Baghabari	113	0	0	0	1	0	0	0	0	Oil
78	118	B Baria	40	1	1	1	1	1	1	1	1	Gas
79	119	Daudkandi	109	0	0	0	1	0	0	0	0	Oil
80	120	Shidhirganj-1	123	0	0	0	0	0	0	0	0	Oil
81	162	Shidhirganj-2	123	0	0	0	0	0	0	0	0	Oil
82	121	Sikalbaha	110	0	0	0	0	0	0	0	0	Oil
83	122	Meghnaghat132	115	0	0	0	0	0	0	0	0	Oil
84	123	Joydevpur	118	0	0	0	0	0	0	0	0	Oil

85	124	Haripur(N)	56	1	1	1	1	0	1	1	1	Gas
86	125	Baghabari(N)-1	48	1	1	1	1	1	1	1	1	Gas
87	163	Baghabari(N)-2	48	1	1	1	1	1	1	1	1	Gas
88	164	Baghabari(N)-3	48	1	1	1	1	1	1	1	1	Gas
89	126	Sidhirganj(N)-1	48	1	1	1	1	1	1	1	1	Gas
90	165	Sidhirganj(N)-2	48	1	1	1	1	1	1	1	1	Gas
91	127	Sikalbaha(N)-1	52	1	1	1	1	1	0	1	0	Gas
92	166	Sikalbaha(N)-2	52	1	1	1	1	0	0	1	0	Gas
93	128	Joydevpur(N)	36	1	1	1	1	1	1	1	1	Gas

B.6: OPF sample output for using units scheduled by classical Lagrange method of scheduling for a peak hour in loading scenario-1 of Table 5.10

Converged in 0.22 seconds

Objective Function Value = 237271.95 $/hr

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| System Summary |

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How many?		How much?	P (MW)	Q (MVAr)
Buses	166	Total Gen Capacity	8215.0	0.0 to 4932.0
Generators	93	On-line Capacity	5938.0	0.0 to 3565.0
Committed Gens	60	Generation (actual)	5138.7	1891.3
Loads	93	Load	4995.5	3095.9
Fixed	93	Fixed	4995.5	3095.9
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	49	Shunt (inj)	-0.0	1612.3
Branches	202	Losses (I^2 * Z)	143.25	994.94
Transformers	0	Branch Charging (inj)	-	587.2
Inter-ties	0	Total Inter-tie Flow	0.0	0.0
Areas	1			

	Minimum	Maximum
	-------------------------	-------------------------------
Voltage Magnitude	0.887 p.u. @ bus 70	1.050 p.u. @ bus 161
Voltage Angle	-36.79 deg @ bus 71	14.72 deg @ bus 165
P Losses (I^2*R)	-	15.68 MW @ line 101-108
Q Losses (I^2*X)	-	82.27 MVAr @ line 100-112

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| Bus Data |

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Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
1	1.038	0.000*	230.00	22.24	16.65	10.32
2	1.033	-0.612	-	-	10.60	6.57
3	1.030	-2.314	-	-	58.00	35.95
4	1.022	-2.654	-	-	21.00	13.01
5	1.015	-3.243	-	-	26.00	16.11
6	1.028	-4.733	-	-	30.00	18.59
7	1.050	-6.421	-	-	24.00	14.87
8	1.010	-3.605	30.00	0.00	78.00	48.34
9	1.013	-3.429	-	-	130.00	80.57
10	1.022	-3.010	22.00	3.88	58.00	35.95
11	1.014	-3.441	-	-	84.00	52.06
12	1.014	-3.369	-	-	10.00	6.19
13	1.014	-3.315	-	-	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
14	1.015	-6.650	22.00	13.00	50.00	30.99
15	1.002	-8.141	-	-	73.00	45.24
16	1.020	-5.912	-	-	61.00	37.80
17	1.017	-7.362	33.00	20.00	113.00	70.03
18	1.000	-8.181	-	-	37.00	22.93
19	1.018	-4.403	-	-	45.47	28.18
20	1.016	-4.370	-	-	85.80	53.17
21	1.003	-5.906	-	-	113.10	70.09
22	1.010	-5.171	-	-	-	-
23	1.005	-5.754	-	-	105.00	65.07
24	0.999	-6.182	-	-	97.50	60.43
25	1.013	-5.444	-	-	-	-
26	1.000	-5.851	-	-	102.00	63.21
27	1.013	-4.804	-	-	16.77	10.39
28	0.988	-6.847	-	-	110.00	68.17
29	1.006	-5.563	-	-	45.00	27.89
30	1.016	-5.380	-	-	71.00	44.00
31	1.004	-5.793	-	-	70.00	43.38
32	1.010	-5.582	-	-	65.00	40.28
33	0.985	-7.274	-	-	83.00	51.44
34	0.998	-6.790	-	-	129.35	80.16
35	1.002	-6.666	-	-	156.00	96.68
36	0.996	-6.617	35.00	21.00	98.67	61.15
37	1.005	-5.899	-	-	80.00	49.58

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
38	1.006	-5.897	105.00	63.00	55.46	34.37
39	0.988	-7.498	-	-	87.00	53.92
40	0.959	-9.734	-	-	114.00	70.65
41	0.973	-9.345	22.00	13.00	80.00	49.58
42	1.029	-3.046	100.00	60.00	54.00	33.47
43	1.000	-6.224	-	-	100.00	61.97
44	1.029	-3.803	90.00	54.00	95.00	58.88
45	1.006	-6.430	-	-	-	-
46	1.038	-0.122	97.00	58.00	63.40	39.29
47	1.035	-1.557	-	-	39.00	24.17
48	1.050	-1.996	202.00	115.38	97.00	60.11
49	1.024	-4.443	-	-	81.00	50.20
50	1.041	-2.484	-	-	29.00	17.97
51	1.042	4.816	14.67	21.42	30.86	19.13
52	1.037	7.006	-	-	30.00	18.59
53	1.045	10.736	-	-	27.76	17.20
54	1.047	11.093	46.24	6.43	-	-
55	1.048	11.756	142.00	61.50	111.00	68.79
56	1.043	11.421	-	-	21.00	13.01
57	0.911	-26.912	-	-	1.20	0.74
58	0.911	-26.845	-	-	70.00	43.38
59	0.907	-27.583	-	-	30.00	18.59
60	0.909	-27.875	-	-	65.00	40.28
61	0.911	-26.058	-	-	44.00	27.27

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
62	0.922	-22.924	-	-	40.00	24.79
63	0.931	-20.592	-	-	4.58	2.84
64	0.898	-31.234	-	-	50.00	30.99
65	0.910	-36.467	-	-	13.20	8.18
66	0.920	-35.610	-	-	38.00	23.55
67	0.937	-36.789	-	-	36.77	22.79
68	0.906	-35.075	-	-	20.00	12.39
69	0.901	-33.108	-	-	33.00	20.45
70	0.887	-33.907	-	-	20.00	12.39
71	0.963	-36.789	23.00	14.00	15.50	9.61
72	0.918	-25.466	-	-	-	-
73	0.914	-27.162	-	-	19.70	12.21
74	0.944	-18.524	-	-	25.00	15.49
75	0.941	-20.080	-	-	50.00	30.98
76	0.930	-23.479	-	-	65.00	40.28
77	0.927	-25.056	-	-	44.00	27.27
78	0.931	-18.725	-	-	50.00	30.99
79	0.962	-13.053	11.00	7.00	28.00	17.35
80	0.966	-12.430	-	-	34.56	21.42
81	0.961	-13.893	-	-	27.51	17.05
82	0.961	-15.910	49.58	30.00	113.00	70.03
83	0.945	-18.112	-	-	73.00	45.24
84	0.959	-16.812	-	-	23.00	14.25
85	0.970	-17.060	-	-	58.00	35.94

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
86	0.962	-18.183	-	-	22.40	13.88
87	0.976	-17.242	-	-	40.79	25.28
88	0.973	-18.197	-	-	24.36	15.10
89	0.970	-19.492	-	-	43.00	26.65
90	0.963	-15.635	-	-	-	-
91	0.989	-14.769	-	-	14.00	8.68
92	1.018	-3.195	-	-	7.00	4.34
93	1.050	-2.001	-	-	-	-
94	1.006	-5.960	-	-	33.80	20.95
95	1.008	-5.251	-	-	30.00	18.59
96	0.925	-20.886	-	-	24.80	15.37
97	1.047	1.421	180.00	73.93	30.88	19.14
98	1.042	0.317	-	-	-	-
99	1.039	-2.628	-	-	-	-
100	1.033	-1.119	150.00	90.00	38.05	23.58
101	1.025	-2.105	170.00	102.00	67.73	41.98
102	1.013	-4.078	-	-	-	-
103	1.039	-2.247	360.00	216.00	-	-
104	1.029	-3.487	-	-	-	-
105	1.043	-2.251	450.00	270.00	44.82	27.78
106	1.039	-2.247	-	-	-	-
107	1.027	-3.029	-	-	-	-
108	0.948	-15.310	-	-	-	-
109	0.964	-12.680	-	-	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
110	0.921	-22.215	-	-	-	-
111	1.011	-4.721	-	-	-	-
112	0.976	-10.878	-	-	-	-
113	0.975	-12.821	-	-	-	-
114	0.997	-12.230	125.00	75.00	-	-
115	1.039	-2.257	-	-	12.45	7.72
116	1.018	-4.403	-	-	-	-
117	0.966	-12.430	-	-	-	-
118	1.050	6.246	50.40	0.00	-	-
119	1.019	-4.427	-	-	-	-
120	1.016	-4.370	-	-	-	-
121	1.015	-3.243	-	-	-	-
122	1.019	-4.418	-	-	-	-
123	1.000	-6.224	-	-	-	-
124	1.050	-2.691	35.00	30.77	-	-
125	1.038	-1.496	100.00	60.00	-	-
126	1.045	8.445	120.00	46.06	-	-
127	1.020	3.593	113.33	0.00	-	-
128	1.022	-4.487	33.00	20.00	-	-
129	1.023	-6.082	11.00	7.00	-	-
130	1.034	-6.081	25.00	15.00	-	-
131	1.050	-0.028	58.68	18.20	-	-
132	1.050	-2.247	17.16	20.96	-	-
133	1.050	0.651	15.79	10.88	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
134	1.050	0.651	15.79	10.88	-	-
135	1.043	5.560	14.15	0.26	-	-
136	1.042	5.029	4.07	0.16	-	-
137	1.043	5.343	10.01	0.18	-	-
138	1.050	13.416	44.56	0.00	-	-
139	1.048	11.761	12.82	0.22	-	-
140	1.048	11.761	12.82	0.22	-	-
141	1.049	12.200	8.55	0.15	-	-
142	1.050	12.797	20.00	0.00	-	-
143	0.911	-26.912	-	-	-	-
144	0.911	-26.912	-	-	-	-
145	0.911	-26.912	-	-	-	-
146	0.911	-26.912	-	-	-	-
147	0.907	-27.583	-	-	-	-
148	0.931	-20.592	-	-	-	-
149	0.930	-23.479	-	-	-	-
150	1.050	10.845	180.00	0.00	-	-
151	1.050	6.761	150.00	13.56	-	-
152	1.050	6.761	150.00	13.56	-	-
153	1.050	2.386	67.64	13.59	-	-
154	1.050	-0.150	19.98	16.48	-	-
155	1.050	-0.150	19.98	16.48	-	-
156	1.050	7.398	180.00	22.93	-	-
157	1.050	7.935	190.00	23.64	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
-----	-------	--------	--------	--------	--------	--------
158	1.050	7.935	190.00	23.64	-	-
159	1.050	0.790	56.55	21.88	-	-
160	1.050	5.619	150.00	6.54	-	-
161	1.050	-5.648	125.00	49.71	-	-
162	1.016	-4.370	-	-	-	-
163	1.050	1.034	48.98	8.76	-	-
164	1.050	1.034	48.98	8.76	-	-
165	1.050	14.725	120.00	0.00	-	-
166	1.021	4.143	10.00	0.00	-	-
			--------	--------	--------	--------
	Total:		5138.74	1891.26	4995.49	3095.87

OPF sample output for using units scheduled by proposed method of scheduling for a peak hour in loading scenario-1 of Table 5.10

Converged in 1.00 seconds

Objective Function Value = 237669.32 $/hr

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| System Summary |

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How many?		How much?	P (MW)	Q (MVAr)
Buses	166	Total Gen Capacity	8215.0	0.0 to 4932.0
Generators	93	On-line Capacity	6129.0	0.0 to 3680.0
Committed Gens	63	Generation (actual)	5133.4	1726.5
Loads	93	Load	4995.5	3095.9
Fixed	93	Fixed	4995.5	3095.9
Dispatchable	0	Dispatchable	-0.0 of -0.0	-0.0
Shunts	49	Shunt (inj)	-0.0	1718.8
Branches	202	Losses (I^2 * Z)	137.89	956.09
Transformers	0	Branch Charging (inj)	-	606.7
Inter-ties	0	Total Inter-tie Flow	0.0	0.0
Areas	1			

	Minimum	Maximum
Voltage Magnitude	0.966 p.u. @ bus 40	1.050 p.u. @ bus 71
Voltage Angle	-34.53 deg @ bus 67	14.20 deg @ bus 165
P Losses (I^2*R)	-	15.36 MW @ line 101-108
Q Losses (I^2*X)	-	86.67 MVAr @ line 100-112

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| Bus Data |

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Bus #	Voltage Mag(pu)	Voltage Ang(deg)	Generation P (MW)	Generation Q (MVAr)	Load P (MW)	Load Q (MVAr)
1	1.033	0.000*	230.00	2.55	16.65	10.32
2	1.029	-0.627	-	-	10.60	6.57
3	1.029	-2.410	-	-	58.00	35.95
4	1.021	-2.715	-	-	21.00	13.01
5	1.015	-3.279	-	-	26.00	16.11
6	1.028	-4.769	-	-	30.00	18.59
7	1.050	-6.457	-	-	24.00	14.87
8	1.011	-3.667	30.00	10.13	78.00	48.34
9	1.013	-3.484	-	-	130.00	80.57
10	1.021	-3.084	22.00	0.00	58.00	35.95
11	1.013	-3.487	-	-	84.00	52.06
12	1.014	-3.412	-	-	10.00	6.19
13	1.015	-3.355	-	-	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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14	1.018	-6.928	22.00	13.00	50.00	30.99
15	1.004	-8.429	-	-	73.00	45.24
16	1.024	-6.292	-	-	61.00	37.80
17	1.021	-7.726	33.00	20.00	113.00	70.03
18	1.003	-8.507	-	-	37.00	22.93
19	1.023	-4.895	-	-	45.47	28.18
20	1.021	-4.864	-	-	85.80	53.17
21	1.009	-6.407	-	-	113.10	70.09
22	1.015	-5.657	-	-	-	-
23	1.011	-6.253	-	-	105.00	65.07
24	1.005	-6.676	-	-	97.50	60.43
25	1.019	-5.954	-	-	-	-
26	1.006	-6.330	-	-	102.00	63.21
27	1.018	-5.293	-	-	16.77	10.39
28	0.994	-7.328	-	-	110.00	68.17
29	1.012	-6.049	-	-	45.00	27.89
30	1.022	-5.873	-	-	71.00	44.00
31	1.010	-6.278	-	-	70.00	43.38
32	1.017	-6.091	-	-	65.00	40.28
33	0.992	-7.759	-	-	83.00	51.44
34	1.005	-7.298	-	-	129.35	80.16
35	1.009	-7.170	-	-	156.00	96.68
36	1.003	-7.131	35.00	21.00	98.67	61.15

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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37	1.012	-6.416	-	-	80.00	49.58
38	1.013	-6.423	105.00	63.00	55.46	34.37
39	0.995	-7.994	-	-	87.00	53.92
40	0.966	-10.202	-	-	114.00	70.65
41	0.980	-9.820	22.00	13.00	80.00	49.58
42	1.033	-3.561	100.00	60.00	54.00	33.47
43	1.006	-6.726	-	-	100.00	61.97
44	1.033	-4.308	90.00	54.00	95.00	58.88
45	1.012	-6.940	-	-	-	-
46	1.041	-0.545	97.00	58.00	63.40	39.29
47	1.035	-1.946	-	-	39.00	24.17
48	1.048	-2.352	202.00	111.79	97.00	60.11
49	1.022	-4.807	-	-	81.00	50.20
50	1.039	-2.842	-	-	29.00	17.97
51	1.041	5.108	17.96	14.26	30.86	19.13
52	1.036	7.447	-	-	30.00	18.59
53	1.045	11.376	-	-	27.76	17.20
54	1.046	11.749	48.69	6.25	-	-
55	1.048	12.423	142.00	61.78	111.00	68.79
56	1.043	12.088	-	-	21.00	13.01
57	1.000	-25.831	-	-	1.20	0.74
58	1.000	-25.773	-	-	70.00	43.38

59	1.003	-26.253	10.00	28.27	30.00	18.59
60	1.002	-26.597	-	-	65.00	40.28

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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61	0.994	-25.233	-	-	44.00	27.27
62	0.992	-22.692	-	-	40.00	24.79
63	0.993	-20.721	-	-	4.58	2.84
64	0.985	-29.974	-	-	50.00	30.99
65	1.008	-34.351	-	-	13.20	8.18
66	1.016	-33.650	-	-	38.00	23.55
67	1.034	-34.528	-	-	36.77	22.79
68	1.005	-32.901	-	-	20.00	12.39
69	1.000	-31.146	-	-	33.00	20.45
70	0.986	-31.796	-	-	20.00	12.39
71	1.050	-34.421	23.00	0.00	15.50	9.61
72	1.003	-24.649	-	-	-	-
73	1.002	-26.086	-	-	19.70	12.21
74	0.999	-18.881	-	-	25.00	15.49
75	0.997	-20.471	-	-	50.00	30.98
76	0.995	-23.408	-	-	65.00	40.28
77	0.998	-24.606	8.00	3.21	44.00	27.27
78	0.984	-19.085	-	-	50.00	30.99
79	0.998	-14.097	11.00	7.00	28.00	17.35
80	1.001	-13.500	-	-	34.56	21.42

81	0.997	-15.008	-	-	27.51	17.05
82	0.998	-17.232	26.23	30.00	113.00	70.03
83	0.985	-19.289	-	-	73.00	45.24
84	0.995	-18.269	-	-	23.00	14.25

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
85	1.004	-18.709	-	-	58.00	35.94
86	0.998	-19.766	-	-	22.40	13.88
87	1.010	-18.942	-	-	40.79	25.28
88	1.007	-19.846	-	-	24.36	15.10
89	1.006	-21.069	-	-	43.00	26.65
90	1.000	-16.966	-	-	-	-
91	1.020	-16.646	-	-	14.00	8.68
92	1.017	-3.261	-	-	7.00	4.34
93	1.048	-2.357	-	-	-	-
94	1.013	-6.485	-	-	33.80	20.95
95	1.013	-5.736	-	-	30.00	18.59
96	0.987	-20.979	-	-	24.80	15.37
97	1.047	1.245	180.00	71.42	30.88	19.14
98	1.042	0.139	-	-	-	-
99	1.043	-3.049	-	-	-	-
100	1.040	-1.831	150.00	90.00	38.05	23.58
101	1.033	-2.731	170.00	102.00	67.73	41.98
102	1.021	-4.642	-	-	-	-

103	1.045	-2.764	360.00	216.00	-	-
104	1.035	-3.994	-	-	-	-
105	1.048	-2.757	450.00	270.00	44.82	27.78
106	1.045	-2.764	-	-	-	-
107	1.034	-3.566	-	-	-	-
108	0.996	-15.977	-	-	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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109	1.002	-13.648	-	-	-	-
110	0.995	-22.008	-	-	-	-
111	1.018	-5.257	-	-	-	-
112	1.008	-12.009	-	-	-	-
113	1.007	-14.296	-	-	-	-
114	1.025	-14.332	112.29	75.00	-	-
115	1.044	-2.773	-	-	12.45	7.72
116	1.023	-4.895	-	-	-	-
117	1.001	-13.500	-	-	-	-
118	1.050	6.733	57.10	0.00	-	-
119	1.024	-4.919	-	-	-	-
120	1.021	-4.864	-	-	-	-
121	1.015	-3.279	-	-	-	-
122	1.024	-4.910	-	-	-	-
123	1.006	-6.726	-	-	-	-
124	1.050	-3.164	35.00	25.55	-	-

125	1.046	-2.958	100.00	50.06	-	-
126	1.045	7.917	120.00	40.83	-	-
127	1.026	4.027	123.09	5.81	-	-
128	1.028	-5.008	33.00	20.00	-	-
129	1.025	-6.362	11.00	7.00	-	-
130	1.037	-6.454	25.00	15.00	-	-
131	1.050	-0.524	58.84	13.72	-	-
132	1.050	-2.752	16.97	16.50	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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133	1.050	0.249	15.98	8.34	-	-
134	1.050	0.249	15.98	8.34	-	-
135	1.043	6.021	17.31	0.31	-	-
136	1.042	5.371	4.98	0.13	-	-
137	1.042	5.688	11.00	0.16	-	-
138	1.050	14.196	46.90	0.00	-	-
139	1.048	12.454	13.50	0.21	-	-
140	1.048	12.454	13.50	0.21	-	-
141	1.049	12.902	9.22	0.14	-	-
142	1.050	13.464	20.00	0.00	-	-
143	1.000	-25.831	-	-	-	-
144	1.000	-25.831	-	-	-	-
145	1.000	-25.831	-	-	-	-
146	1.000	-25.831	-	-	-	-

147	1.004	-25.741	9.00	0.13	-	-
148	0.993	-20.721	-	-	-	-
149	0.995	-23.408	-	-	-	-
150	1.050	10.669	180.00	0.00	-	-
151	1.050	6.032	150.00	5.31	-	-
152	1.050	6.032	150.00	5.31	-	-
153	1.050	1.854	70.74	5.22	-	-
154	1.050	-0.805	20.39	8.17	-	-
155	1.050	-0.805	20.39	8.17	-	-
156	1.050	6.743	180.00	14.62	-	-

Bus	Voltage		Generation		Load	
#	Mag(pu)	Ang(deg)	P (MW)	Q (MVAr)	P (MW)	Q (MVAr)
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157	1.050	7.276	190.00	15.33	-	-
158	1.050	7.276	190.00	15.33	-	-
159	1.050	0.312	58.92	13.47	-	-
160	1.050	5.091	150.00	0.93	-	-
161	1.050	-9.550	91.80	20.43	-	-
162	1.021	-4.864	-	-	-	-
163	1.050	-0.439	48.30	0.00	-	-
164	1.050	-0.439	48.30	0.00	-	-
165	1.050	14.196	120.00	0.00	-	-
166	1.027	4.570	10.00	0.18	-	-
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		Total:	5133.38	1726.55	4995.49	3095.87