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Various Approaches to Addressing Unit Commitment Issues in Electric Power Plants

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***Abstract*— In this work, the Unit Commitment (UC) problem has been investigated. In order to ensure that the demand for energy is constantly met at the lowest feasible cost, the challenge is in determining which subset of generating units within a power system is particularly effective. Additionally, heuristics, dynamic programming, and Lagrangian relaxation are some of the approaches that are being researched. The uniform convergence (UC) problem is characterized by a number of intrinsic complexities, and each of these techniques is designed to accommodate those complexities. There are a great number of operational restrictions that are responsible for these levels of complexity. These kinds of limitations include things like the requirements for the spinning reserve, the restraints on the thermal unit, the availability of fuel, and the emission regulations. The purpose of this research is to provide light on the effectiveness of a number of contemporary optimization approaches, including enumeration methods, integer programming, and evolutionary algorithms, among others. This research examined how a regional power system operated normally and under emergency situations by studying distribution of power loads alongside generator capacity as well as backup reserves and inter-regional power transfer. The analysis examined both major power plant outages which disrupt the system balance especially when units 7 and 8 fail and what happens when power demand exceeds capacity. The analysis demonstrated that the system has acceptable performance during regular operations but significantly depends on Southern region resources after unit failures cause reduced spinning reserves with substantial interchanges occurring. Tests of increased power demand confirmed that Eastern and Western regions faced essential power deficits reaching 650 MW. System reliability depends on proper distribution of generating sources combined with strategic reserve margin reinforcement together with improved power flow flexibility between regions.**

Keywords—Unit Commitment (UC), Power system optimization, Generating units, Heuristics, Dynamic programming, Lagrangian relaxation, Operational constraints, Spinning reserve, Thermal unit constraints, Fuel availability, Emission regulations, Optimization techniques, Enumeration methods, Integer programming, Evolutionary algorithms, Power load distribution, Generator capacity, Backup reserves, Inter-regional power transfer, Power plant outages, System reliability, Reserve margin reinforcement, Power flow flexibility.

1. INTRODUCTION

Operation and planning tasks for electric power systems face an essential operational difficulty named Unit Commitment (UC) [1]. The problem sets times for when power units should be turned on or off and sets their operating levels during a planning period of 24 to 168 hours while seeking to minimize operating expenses without exceeding system demand or operational limitations [2]. Optimization unit commitment in power systems is presented in Figure 1. The scheduling procedure requires adjustments to match different energy usage patterns shaped by day-to-day and week-to-week as well as seasonal changes. Power companies need to select actively or idle their power generators and determine operational hours in order to achieve reliable operations and economic efficiency at the same time [3]. The Utility Cut problem uses mathematical modeling through mixed-integrity programming to evaluate technical constraints that include generator limitations together with resource adjustment capabilities and machine operation duration requirements and power backup policies [4]. Numerous solution techniques exist for dealing with the complex UC problem because of its difficult nature. Industrial use of the priority list and dynamic programming approaches prevails because such techniques deliver robust solutions while maintaining practical computational times [5].

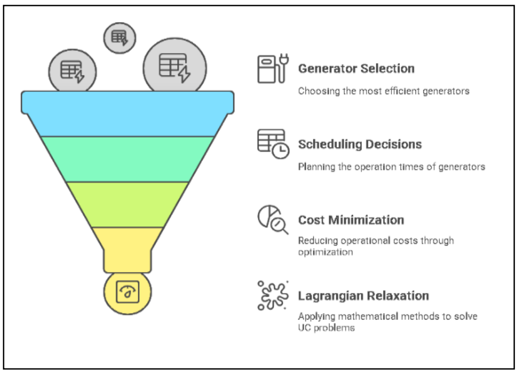

Fig. 1. Optimization unit commitment in power systems

Adopted techniques need improvement because power systems become increasingly sophisticated while renewable energy connects to traditional systems along with limited operational abilities of nuclear power plants [6]. Lagrangian Relaxation stands out as one of the most effective approaches to solve this problem. The method repurposes the initial problem into a dual function by adding cost constraints and setting weights through Lagrange multipliers to solve it more efficiently. A diverse set of modeling methods for the unit commitment (UC) problem has been developed by [7] with different strengths and weaknesses. The analysis presented essential research areas that require improvement to enhance computational speed under uncertain situations and advance startup procedures modeling along with storage technologies and non-dispatchable power integration into systems. The research established that UC planning periods need to match medium-term operational needs. The comparative assessment delivered definitive standards about modeling detail as well as problem scale and computational performance to establish solid bases for power system optimization advancement.

Virtual power plants (VPPs) with demand response programs, energy storage devices, and wind farms (WFs) have been discussed in [8] in relation to energy management. The method considered the unpredictability of system and VPP loads, WF power output, and day-ahead market energy and reserve prices as factors. This method was used at the electrical power transmission level as a hybrid stochastic-robust scheduling for the VPP. The uncertainties of the load and WF power are represented by bounded uncertainty-based robust optimisation, while the uncertainties of the day-ahead market prices are modelled by scenario-based stochastic programming. Evidence from these markets indicates that the proposed method can successfully coordinate VPPs.

The best way to schedule power plants and virtual power plants for the next day and for extra services was through a complex planning method that uses a multi-stage approach, as shown in another study [9]. The manufacture of solar panels and the ancillary services market's requests for unpredictability were both replicated in the scenarios. The difficult multistage stochastic program is addressed by proposing a new decomposition approach. The approach is tested on three major types of power plants: a virtual power plant that integrates a combined cycle with battery and solar fields, a combined heat and power combined cycle with thermal storage, and a natural gas-fired combined cycle. In the end, the results showed that the conventional power plant's revenues could be raised by as much as 13.58% using the proposed stochastic optimisation method. For the combined heat and power (CHP) and virtual power plant (VPP) scenarios, the method helped identify a practical and effective operating schedule as presented in Figure 2.

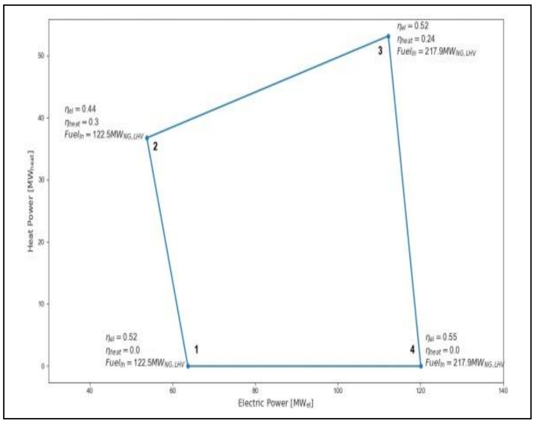

Fig. 2. Operating map of the CHP generator according to [9]

Research today aims to establish UC strategies which adapt to systems requiring fluctuating or low net demand profiles particularly in power systems utilizing high levels of renewable resources. The introduced enhancement strategies strive to boost power system reliability alongside economic stability under uncertain conditions. This paper presents a comprehensive review of various methods used to address the UC problem, from classical mathematical approaches to modern metaheuristic and relaxation-based techniques. The objective is to explore the strengths and limitations of each approach in real-world applications and to highlight the need for adaptable and intelligent UC models that can meet the evolving demands of contemporary power systems. Industrial and mathematical approaches to handle the UC problem together with contemporary metaheuristic schemes and relaxation-oriented algorithms receive thorough analysis in this research. The discussion will demonstrate the advantages and challenges of different methodologies in practical power system operations prior to advocating for adjustable intelligent UC models which adapt to

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modern power grid requirements. For this regard, this study presents a case study that includes a detailed operational analysis of power generation units distributed across the Southern, Eastern, and Western regions within a unified power grid. It examines the configuration and coordination of active units in each region under varying system conditions, including normal operation, unit outages, and increased load demand. The study focuses on generation capacity, regional demand coverage, spinning reserve availability, and the role of power interchange between regions. By simulating multiple scenarios, the case study provides insight into the operational dynamics and interdependencies of regional generation units within the broader system framework.

2. EVOLUTION OF UNIT COMMITMENT STRATEGIES IN POWER SYSTEMS

Multiple studies have proven that power usage depends substantially on human behavior patterns. The nighttime demand level remains low until morning when it rises while reaching its maximum in evening hours before returning to lower levels during late night. Short and long-term forecasting methods for electric load predictions must be established because electricity demand fluctuates based on weekend days and varies according to weather conditions [5].

The first priority for operating power-generating units relied solely on obtaining maximum efficiency from units. Research advances led to the selection of input-output cost curves as the key decision-making basis for optimal operations. These analytic solutions enabled both better planning of unit operations and decreased operational expenditures [3].

Operating electrical power systems requires addressing the unit commitment problem as their most significant operational challenge. The procedure seeks to define the best timeline of generating unit operations that satisfies customer requirements at minimum expense. The unit commitment problem has been solved through dynamic programming and the branch-and-bound method together with Lagrangian relaxation. Current research finds that power system performance and computational speed must improve along with improved operating algorithms for startup replication and lengthened unit commitment periods to support medium-term activities involving water management in hydropower operations and fuel acquisitions and financial arrangements. The representation of immediate power demand changes for thermal power facilities stands as essential because current and upcoming electricity markets incorporate rising levels of uncontrollable energy sources [10].

The implementation of these innovations enables the successful adoption of alternative energy storage methods which enhances operational systems while decreasing financial expenses (See Figure 3).

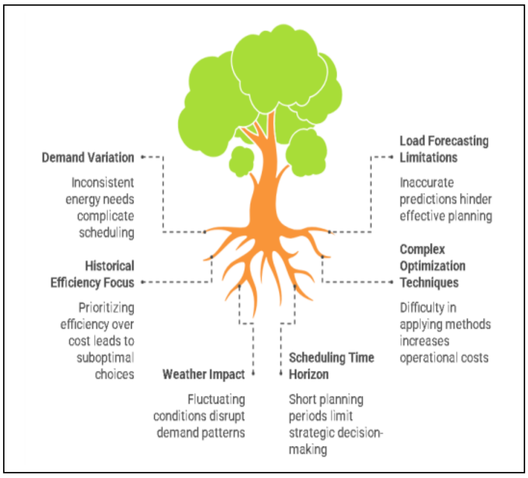

Fig. 3. Inefficient Unit in power system.

3. THE UNIT COMMITMENT (UC) DEFINITION AND ITS PROCESS

The goal of solving the Unit Commitment (UC) problem is to minimise operational costs for a given day by figuring out the optimal sequence for bringing in and shutting down units over time. It is defined as "the problem of finding the order in which the units are to be brought in and the order in which the units are to be shut down over a period of time so that the total operating cost involved on that day is minimum" when discussing the Unit Commitment (UC) problem [11].
Unit commitment problem plans for the best set of units to be available to supply the predicted or forecast load of the system over a future time period.

- When the load increases, the utility has to decide in advance the sequence in which the generator units are to be brought in.
- When the load decreases, the operating engineer needs to know in advance the sequence in which the generating units are to be shut down.

The power system operations rely on Unit Commitment (UC) scheduling to determine which generating units will provide electricity based on forecasts that cover durations between 24 hours and one week. The main objective of the UC system involves selecting the lowest cost mix of operating units for each time interval and maintaining system reliability throughout every operational period.
The forecasting phase starts with load forecasting to obtain projected electricity demand numbers per hour for the planned duration. Operators need to decide the units for

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commitment and decommitment which requires determining their start and stop sequences according to projected load data. System operators need to consider all the expenses from start and stop operations in addition to operating limits and maintenance plans as well as minimum operation periods and backup requirements and speed constraints.

The formulation of the UC problem consists of mixed-integer optimization using binary variables for unit status control and continuous variables for power output levels. Minimizing operational costs that include fuel expenditure and start-up/shut-down expenses with other adjustable operating expenses stands as the main objective [12].

The UC problem receives solutions through various developed approaches which include [13]:

- Priority list methods serve as a generation scheduling approach that positions various power generators by their operational efficiency and cost reduction potential.
- Dynamic programming splits up the optimization problem into stages before locating the best solution route.
- Lagrangian relaxation approaches the problem by dividing it into smaller independent sub-parts through reduced coupling restrictions.
- Complex large-scale systems benefit from solution algorithms known as Metaheuristic algorithms including Genetic Algorithms Particle Swarm Optimization and Simulated Annealing [14].

Modern unified control processes now unite renewable energy systems together with energy storage solutions with demand management protocols thus making the problem adaptable yet challenging to solve. Multiple challenges from increasing wind and solar power adoption in the power grid demand UC strategies which combine flexibility with adaptability for managing unpredictable circumstances as presented in Figure 4.

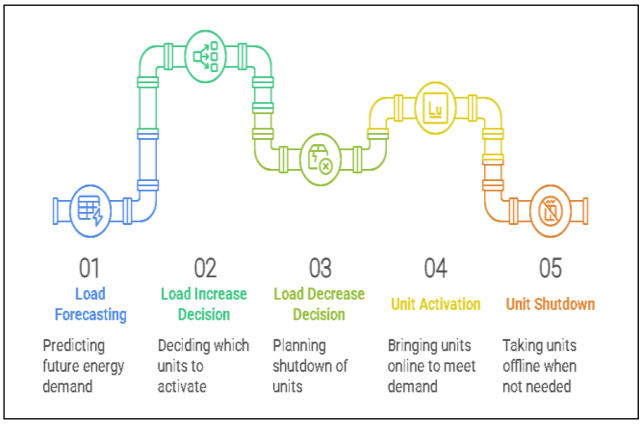
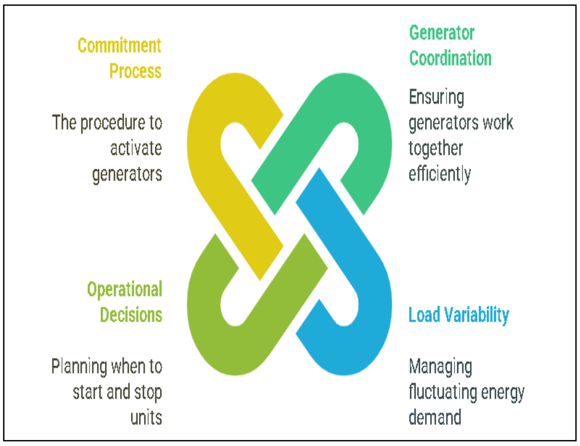


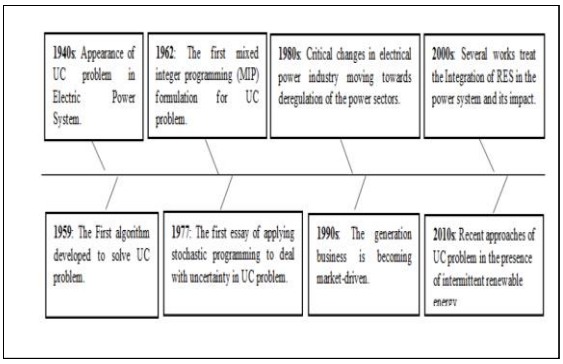
Fig. 4. The process of unit in power system.

4. STATEMENT OF UNIT COMMITMENT (UC) PROBLEM

The Unit Commitment (UC) problem conducts efficient operating decisions for numerous generation units that serve the fluctuating electricity demand aimed at reducing costs or achieving maximum operational revenue. The power system confronts a substantial change in electricity load through each day as specific time periods experience maximum usage requirements. The reliability of the system depends on creating advance plans for generating unit activation timing along with grid connection protocols and procedures to safely deactivate units after service. Retailers use UC computational tools to determine essential scheduling decisions which control the system operations. A generating unit becomes committed to operation when the scheduling process puts it into service. Starting up a unit means beginning its operation followed by synchronization with the electric grid to allow power delivery. The principal issue in unit commitment processes requires finding the best sequence of unit operations to meet projected demands across different operational boundaries [15]. Figure 5.a shows component of unit commitment problem, and Figure 5.b presents UC problem's evolution through time.



(a)



(b)

Fig.5. (a) component of unit commitment problem, (b) Summary of UC problem's evolution through time.

5. COMPARISON WITH ECONOMIC LOAD DISPATCH

The ELD procedure distributes system load among available generating units that are in operation with the goal to reduce operating expenses. All units are assumed to be available for power generation and the system operates

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from an hourly perspective as a short-term horizon [16]. ELD establishes the power levels at each generator for peak efficiency according to present system requirements. The longer planning timeframe of Unit Commitment (UC) establishes which units should be activated or deactivated starting from 24 to 168 hours. The process of Unit Commitment works to incorporate diverse operational boundaries which define start-up and shut-down expenses and mandatory operation times and system backup needs [17]. The continuous power output variables in ELD are a simpler problem compared to UC which needs optimization for both continuous and binary decisions [18]. Figure 6 shows economic dispatch vs. unit commitment.

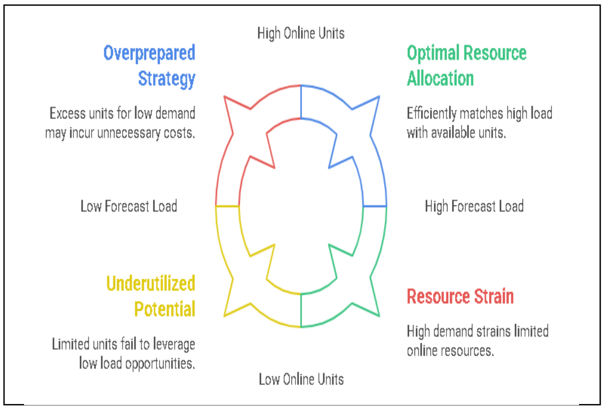

Fig. 6. Economic dispatch vs. unit commitment.

Utility systems, such as electric power, undergo cyclical demand as a result of the regular cycles that human activity follows. The demand is higher during the day and early evening, and it is lower during the late night and on the weekends. It is not feasible from a financial standpoint to have all of the generation units operating in order to meet peak demand at all times. Instead, units are either committed (turned on) or decommitted (shut off) depending on the customer's need. The primary difference between economic dispatch and unit commitment is that the former optimises the output of units that are already operating, whilst the latter specifies which units should be turned on in the first place over a period of time, such as a day or a week, in order to get the lowest possible overall cost. Testing various combinations of available units and applying economic dispatch within each subset are both necessary steps in the process of finding a solution to the unit commitment dilemma. Based on the example, it is not necessarily the most cost-effective approach to run all of the units; rather, it is contingent upon the cost of fuel, the capacity of the units, and the operational constraints [19].

Modern power system optimization technology has exposed growing difficulty levels and computational requirements of unit commitment (UC) scheduling particularly in thermal power plants. The rising incorporation of renewable power systems causes unpredictable load patterns which requires advanced scheduling methods to address this system behavior. Scientists have developed enhanced unit commitment solutions by integrating mixed-integer programming with machine learning reinforcement learning methods to boost speed and reliability [20].

The creation of weekly, monthly and seasonal scheduling patterns has acquired paramount importance because it helps handle recurring load demand cycles along with seasonal changes. Strategic unit decommitments in low-demand periods allow businesses to save considerable expenses. The implementation of this practice delivers substantial benefits to thermal power companies because thermal units require expensive startup and shutdown activities but hydroelectric facilities maintain low operating costs.

Spatial-temporal deep learning frameworks assist in generator commitment schedule predictions because they address power system data requirements for space and time relationships. By employing these models, the security-constrained unit commitment process becomes faster yet achieves equivalent solution quality results [21].

Power system operators now use enhanced UC scheduling methods that combine data science methods alongside classical optimization methods to optimize both economic performance and operational efficiency in power grids coping with complex system dynamics and renewable integration as presented in Figure 7.

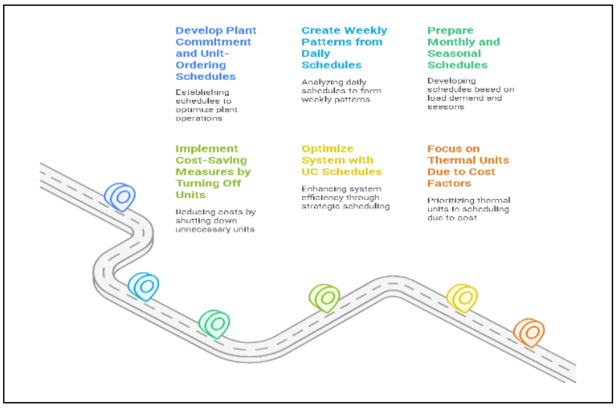

Fig. 7. Unit Commitment Optimization in Thermal plants.

6.HEURISTIC METHODS

Heuristic methods are ways that are empirical and computer-assisted. They are used to guide decisions on unit commitment (UC) through a priority list, while also including operational constraints in a manner that is not rigorous. As shown in [17], these approaches often begin by turning off all of the units and restarting them in accordance with a predetermined priority order. This priority order is frequently decided by the average full-load cost of each unit, which is derived by multiplying the net heat rate at full load by the fuel cost. In order to reduce operational expenses as much as possible, the recommended technique begins with a schedule that is realistic and then iteratively adjusts the hours at which it starts up and shuts down. A sub-optimizer is incorporated into this process in order to establish a viable and almost optimal commitment. This is then followed by an optimiser, which refines the timetable through repeated iterations until there is no further cost savings noticed.

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Additionally, heuristic strategies have been used to short-term UC problems through the utilisation of expert systems. Figure 8 shows the methods of heuristic for unit commitment.

Several benefits can be gained from using heuristic methods :[13]

- The capacity for adaptability in the face of operational restrictions
- The possibility of producing solutions that are feasible is high.
- Memory and computational time requirements that are relatively low.

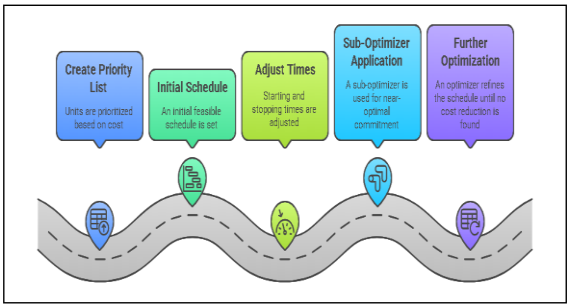

Fig. 8. Methods of heuristic for unit commitment.

A research effort succeeded in resolving the Security-Constrained Unit Commitment (SCUC) problem through its approach to the difficult mixed-integer nonlinear programming application with various operational restrictions including load balancing alongside spinning reserves and voltage control and ramping restrictions. The introduced approach applies single and multi-objective evolutionary algorithms (EAs) through a unique hybrid framework containing real-coded and binary operators that operate through coevolution in both directions. A proposed ensemble scheme handles opposing optimization needs by finding minimum power generation prices, start-up/shut-down expenses and power quality issues and voltage fluctuations while assessing IEEE test cases for both daily and weekly operational schedules. The simulation tests showed that the proposed algorithm achieved near-global optimal solutions which proved superior to multiple existing multi-objective evolutionary algorithms as presented in Figure 9 [22].

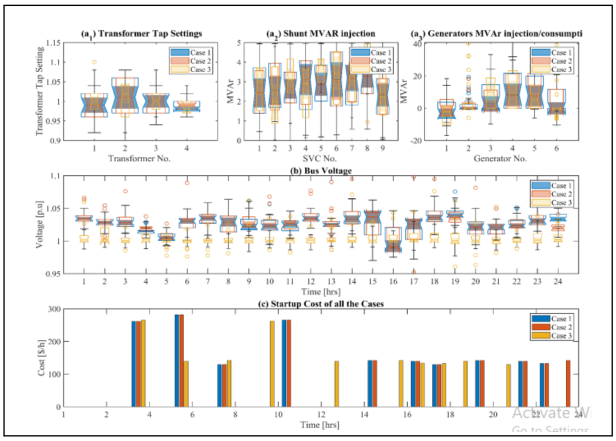

Fig. 9. Single-Objective Decision Variables: Transformer Tap Ratio, Shunt MVAr Injection, Generator Reactive Power, Bus Voltage Profile, and Total Startup Cost Over the Time Horizon.

7. CONSTRAINTS IN U.C.

To effectively address the Unit Commitment (UC) issue, it is necessary to take into account a wide variety of constraints, including those that are technical, economic, and operational in nature. The feasibility and efficiency of scheduling generation units across a predetermined planning horizon are both influenced by these limits for scheduling purposes [20]. The UC problem's primary purpose is to reduce the entire operating cost of the power system as much as possible. This cost typically includes the following components [22]:

$$\text{Total Production Cost} = \text{Fuel Cost} + \text{Start} - \text{up Cost} + \text{Shutdown Cost} + \text{Maintenance Cost}$$

Additional cost components, such as fines for unserved load and long-term investment costs, may also be incorporated into more extensive UC formulations in order to more accurately reflect the dynamics of the real-world system and the objectives of policy [21].

7.1 Requirements for the Reserves of the Power System:

a. Spinning Reserve

The term "spinning reserve" refers to the surplus generating capacity that is generated by synchronised generators that are already online and are able to react rapidly to sudden changes in load or generator outages. This is how it is computed:

$$\text{Spinning Reserve} = (\sum \text{Generation Output of All Online Units}) - (\text{System Load} + \text{Transmission Losses})$$

The presence of this reserve guarantees the dependability of the system and the stability of the grid in the event of crisis [20].

b. Static Reserve

On the other hand, static reserve is the additional installed generation capacity that is in excess of the annual peak demand that is predicted. For the purpose of managing equipment failures or unanticipated outages, this reserve margin is essential since it provides a buffer to ensure that there is sufficient supply over the long term [18].

7.2 Thermal Units

Because of their physical and mechanical features, thermal power units create a unique set of operational issues. These include the following [1]:

- Due to thermal stress and startup expenses, a thermal unit must be in that condition for a predetermined amount of time after it has been turned on or off. This is the minimum amount of time that it can be in either state.

- There are limitations to the ramping process during startup and shutdown. Thermal generators are unable to achieve full load instantly; instead, they require a ramp-up phase in order to reach steady output. It is also necessary for them to have regulated ramp-down procedures in order to shut down.
- Temperature Sensitivity: Excessive cycling or sudden variations in temperature can lead to wear and damage, which requires careful scheduling in order to preserve longevity and reduce the costs of maintenance.

As a result of these limitations, the scheduling of thermal units requires not only economic considerations but also the feasibility of their functioning.

a) MINIMUM UP TIME

- Once the unit is running, it should not be turned off immediately.

b) MINIMUM DOWN TIME

- Once the unit is decommitted, there is a minimum time before it can berecommitted.

c) CREW CONSTRAINTS

- If a plant consists of 2 or more units, they cannot be turned on at the same time
- since there are not enough staff to attend all the units at a time.

d) START UP COST

- A start-up cost is incurred when a generator is put into operation. The cost is dependent on how long the unit has been inactive.
- While the start-up cost function is nonlinear, it can be discretized into hourly periods, giving a stepwise function.
- The start-up cost may vary from a maximum to a very small value if the unit was only turned off recently, and it is still relatively close to the operating temperature.
- Two approaches to treating a thermal unit during its down state:
- The first approach (cooling) allows the unit ‘s boiler to cool down and then heat back up to a operating temperature in time for a scheduled turn-on.
- The second approach (banking) requires that sufficient energy be input to the boiler to just maintain the operating temperature. Similarly, shut-down cost is incurred during shutting down generating units. In general, it is neglected from the unit commitment decision [2].

I. OTHER CONSTRAINTS

In addition to system and unit constraints, there are other constraints that need to be considered in the UC decision. They are described as follows:

A. FUEL CONSTRAINTS:

- Due to the contracts with fuel suppliers, some power plants may have limited fuel or may need to burn a specified amount of fuel in a given time.
- A system in which some units have limited fuel, or else have constraints that require them to burn a specified amount of fuel in a given time, presents a most challenging unit commitment problem.

B. MUST RUN UNITS:

- Some units are given a must-run status during certain times of the year for reason of voltage support on the transmission network or for such purposes as supply of steam for uses outside the steam plant itself.
- The must run units include units in forward contracts, units in exercised call/put options, RMR units, nuclear power plants, some cogeneration units, and units with renewable resources such as wind- turbine units and some hydro power plants.

C. MUST-OFF UNITS:

- Some units are required to be off-line due to maintenance schedule or forced outage. These units can be excluded from the UC decision.

D. EMISSION CONSTRAINTS:

- There are some emissions like Sulphur dioxide, nitrogen oxides, carbon dioxide, and mercury which are produced by fossil-fueled thermal power plants.
- The amount of emission depends on various factors such as the type of fuel used, level of generation output, and the efficiency of the unit.
- The production cost minimization may need to be compromised in order to have the generation schedule that meets the emission constraints [2].

8. UNIT COMMITMENT SOLUTION METHODS

The Unit commitment problems are very difficult to solve, for that consider the following situation,

1. A loading pattern for the M periods using load curve must be established.
2. Number of units should be committed and dispatched to meet out the load.
3. The load period and number of units should

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supply the individual loads and anycombination of loads.

There are many classical approaches have been developed and implemented successfully. Some of the approaches are [15] as presented In Figure 10.

- Enumeration Technique or Brute Force technique
- Priority List Method
- Dynamic Programming
- Lagrange Relaxation
- Integer and Mixed integer programming
- Bender's decomposition
- Branch and Bound

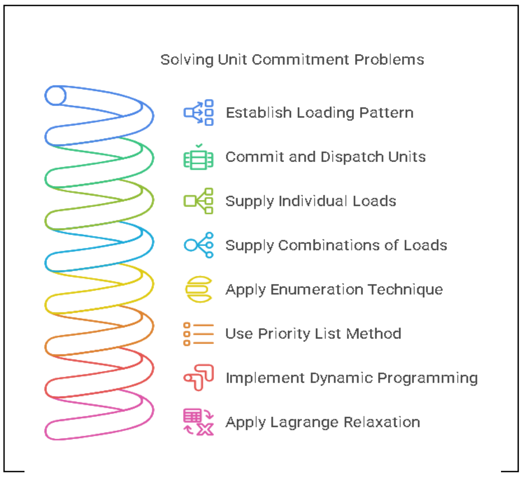

Fig. 10. Solving Unit Commitment Problems.

- **Other non – classical approaches are**

1. Genetic Algorithms
2. Greedy random adaptive search procedure
3. Particle swarm optimization
4. Simulated annealing

The unit responsibility issue is a particularly difficult streamlining issue. This is due to the numerous ways in which the power system's producing units can be turned on or off. These concerns have been investigated using various exact and approximative arrangements. Some of the current efforts to solve the problem are discussed below:

A. Order of Priority:

Priority ordering, which loads the most efficient unit first and subsequently the less efficient units in ascending order as the load increases, is a simple but optional solution to the problem. The need request is based on the typical creation of each unit, neglecting the least up-or-margin time, starting cost, and so on. Most need list plans are built around a simple shut down calculation, which may be as follows [1, 3]:

- Check to verify if lowering the next unit on the priority list will leave enough generation to fulfill the load while still meeting the spinning reserve requirement. In the event that not, keep working; presuming yes, proceed to the next stage.
- Determine how many hours it will be before the dropped unit requires another servicing call. • Proceed to the last step if the number of hours is less than the minimum shut down period; otherwise, proceed to the following step.
- Determine the two costs, the first of which is the unit's up-state hourly production for the following "h" hours. Second is the same amount for "down state," and when you factor in the initial cost of cooling or banking the unit, it should be turned off; otherwise, leave it running.
- Perform the same steps for each subsequent unit on the priority list and for the remaining units. By grouping or combining two or more units, the priority list method can be improved in a number of ways.

B. Programming with Dynamism:

Dynamic programming is based on the principles of optimality explained by Bellman in 1957. It states that 'an optimal policy has the property, that, whatever the initial state and the initial decisions are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision.

This method can be used to solve problems in which many sequential decisions are required to be taken in defining the optimum operation of a system, which consists of a distinct number of stages. However, it is suitable only when the decisions at the later stages do not affect the operation at the earlier stages.

It states that subsequent decisions cannot be influenced by the initial decision, regardless of the beginning state or decisions. This method can be used to tackle problems requiring a large number of judgments to identify the system's best operation over multiple stages. However, it is only suitable when decisions made later in the process have no impact on previous phases of operations. It has numerous advantages, the most significant of which is that the problem is reduced in scope. If the priority list was arranged in descending order of average cost rate, the shipment and bond would be correct [13, 10].

- There are no load charges.
- The attributes of the unit's input and output are linear.
- There are no constraints.
- The initial costs are fixed. The DP approach's fundamental steps for preparing the UC table are as follows:
- Begin at any time with any two units in mind.
- Set up two units' combined output at distinct load levels.
- Choose the cheapest combination of the two units. At each level, it is observed that the in economics, a unit or both units are run with a certain load shared between them. •Get the expense bend of the two units that can be treated as the expense bend of the same unit.
- Presently Add third unit and rehash the methodology, note the working blend with third unit are not needed to be worked out, which saved time in computation.

- Repeat the procedure until all of the available units have been used up. The best thing about this method is that it has the best way to load "k" units, and it will be easy to find the best way to load "k+1" units (See Figure 11).

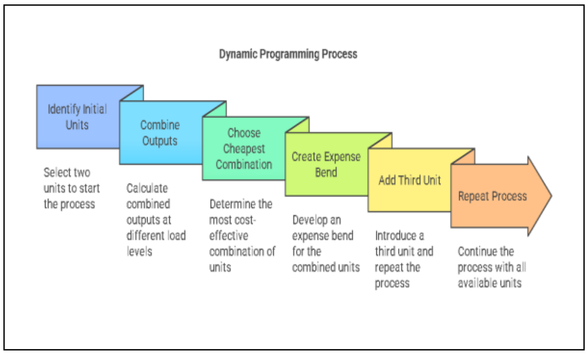

Fig. 11. Dynamic Programming Process.

- **Dynamic programming in unit commitment**

This method can be used to solve problems in which many sequential decisions are required to be taken in defining the optimum operation of a system.

Generally, Dynamic programming in unit commitment is a systematic way of deciding the unit to start or stop.

If a system has n units, there would be 2n – 1 combination which the dynamic programming method enumerates (itemize) feasible schedule alternatives and comparing them in terms of operating costs.

C. Lagrange's Relaxation:

The Unique Programming strategy has many drawbacks for enormous power frameworks with many creating units. This is because the dynamic programming solution had to be forced to reduce the number of combinations that needed to be tested in each time period [20]. Lagrange's method eliminates all of these drawbacks. The Dual optimization approach underpins this numerical approach (See Figure 12). The linear programming problems are broken down into master problems and subproblems that are easier to handle using this approach. Lagrange's multiplier, which can be added to the master problem to produce the dual problem, can be linked to the subproblems. After that, this dual issue is resolved. Unit commitment problems are changes in terms of the cost function, a set of constraints associated with each unit, and a set of system constraints that are divided into a primal problem and a dual problem in order to achieve the best possible solution. The objective function of the unit commitment problem is the primal subproblem, and the constraints and objective function are combined with Lagrange multipliers in the dual problem. By "relaxing," or ignoring, the coupling constraints, the Lagrange relaxation method solves the unit commitment problem. Dual optimization is used to accomplish this [1].

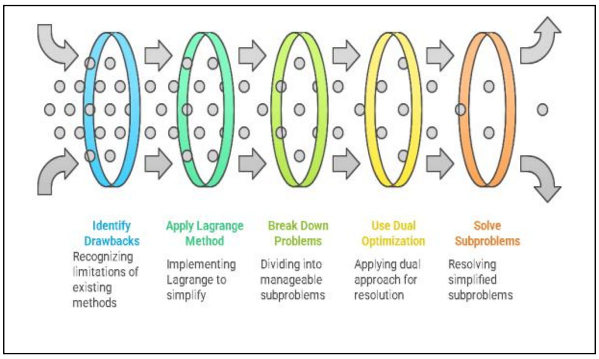

Fig. 12. Optimizing Unit Commitment Through Lagrange and Dual Methods.

9. CASE STUDY: OPERATION UNITS FOR SOUTHERN, EASTERN, AND WESTERN REGIONS IN LIBYA COUNTRY

The study examines electrical power generation management and load balancing between three interconnected areas of Southern and Eastern and Western regions as shown in Figure 13. The regions contain multiple generating units that operate within their predefined capacity constraints linked to their corresponding load requirements. The energy transmission network consists of different power lines that enable power transmission between zones but maintain certain operational limits. The system attempts to balance operations and reduce economic expenses by implementing unit commitment strategies and dispatch procedures to handle power outages or increasing loads.

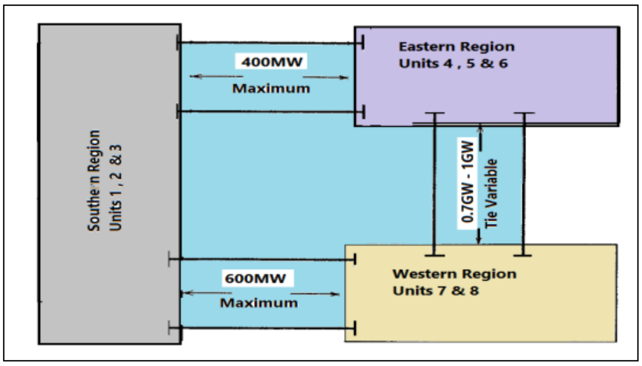

Fig. 13. Case Study: Operation Units for Southern, Eastern, and Western Regions.

Case A: Normal Operation – Load Demand (5050 MW)

Under base conditions the system has 5050 MW of total demand and all units operate. The Southern power region delivers excess energy equivalent to 450 MW which matches the electricity deficit of Eastern region. The entire Western region shows perfect balance between supply and demand. The tie-line between South and East helps balance the 450 MW short supply in Eastern region but operates under the 400 MW transfer cap. A total of 50MW additional local power generation will come from Eastern units 5 or 6 until the demand reaches 5050MW. The proposed operational approach achieves system stability through technical and economic boundaries involving the information provided in Table 1.

Table. 1. Normal Operation – Load Demand (5050 MW).

Region	Unit Outputs (MW)	Unit Capa-cities (MW)	Gener-ation (MW)	Demand (MW)	Spinning Reserve	Inter-change
Southern	300, 700, 300 (1–3)	400, 800, 500	1300	850	450	450 MW Out → East
Eastern	800, 600, 250 (4–6)	1000, 900, 500	1650	2100	—	450 MW In ← South
Western	1200, 1200 (7–8)	1200, 1500	2100	2100	0	Balanced

Case B: Unit 7 Offline

The simulation demonstrates the conditions that occur following Unit 7's outage within Western region totaling 900 MW power production. The interrupted supply zone needs power transfers from nearby functioning zones as a safety precaution. The 900 MW power shortfall in the Western region becomes apparent after Unit 7 goes offline as Table 2 displays. The generation output from Eastern and Southern regions combined helps transfer 700 MW power to the Western zone for resolution. The network operation stays within constraints but reserve capacity operates at reduced levels as compared to the base case configuration.

Table. 2. Unit 7 Offline – Load Demand (5050 MW).

Region	Active Units	Generation (MW)	Demand (MW)	Spinning Reserve	Interchange
Southern	Units 1–3	1400	850	550	550 MW Out → West
Eastern	Units 4–6	2250	2100	150	150 MW Out → West
Western	Unit 8 only	1400	2100	0	700 MW In ← South+East

Case C: Unit 8 Offline

The deactivation of Unit 8 (which has a power capacity of 1200 MW) occurs within this case. The Western power region depends exclusively on Unit 7 operations which creates an extensive energy deficiency according to Table 3. The Western region lacks enough power supply to meet its needs by 900 MW. The Eastern and Southern regions bear the entire power demand while increasing their own energy production to meet the needs and transmitting electricity across the interconnection. The system stays in equilibrium though it functions right at its maximum transfer capacity boundaries

.

Table. 3. Unit 8 Offline – Load Demand (5050 MW).

Region	Active Units	Generation (MW)	Demand (MW)	Spinning Reserve	Interchange
Southern	Units 1–3	1450	850	600	600 MW Out → West
Eastern	Units 4–6	2400	2100	300	300 MW Out → West
Western	Unit 7 only	1200	2100	0	900 MW In← South &East

Case D: The system demand reaches 5700 MW

During this scenario the power demand across the whole system grows from 5050 MW to reach 5700 MW. The calculated estimated demands stem from historical analysis of demand proportions (See Table 4). Each regional power demand amount reaches 2370 MW with the Eastern and Western areas but the Southern area increases its request to 960 MW. System operators have insufficient power generation capacity of 650 MW as the Eastern region faces the most severe shortages. The Southern region has an excess electrical capacity of 340 MW that does not fulfill the existing shortfalls. The available spinning reserves cannot substitute the loss of a major unit. System frequency can drop enough to cause outages because generation capacity remains the same along with tie-line capabilities.

Table. 4. Case study – Load Demand Increase to 5700 MW.

Region	Generation (MW)	Estimated Demand (MW)	Surplus/ Deficit (MW)
Southern	1300	960	340
Eastern	1650	2370	-720
Western	2100	2370	-270
Total	5050	5700	**-650 MW (Total Deficit)**

10. DISCUSSION

This section discusses the main results obtained of the study cases as following:

- Case A: Normal Operation – Load Demand (5050 MW)

In a normal state of play, the system has managed to cover 100 percent of their demands and generate 5050 MW of total generation. Mathematically, 25.7 percent of total generation comes out of the Southern region, 32.7 percent out of the Eastern region and 41.6 percent out of the Western region. The Southern region experiences a surplus of 450 MW (53% more than the local demand), which is transferred to the Eastern one. Eastern region has a deficit of 450 MW (21.4 percent of its demand) and the Western region is perfectly balanced. The spinning reserve capacity is 450 MW or 8.9 percent of system demand which is

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healthy. Quantitatively, such a scenario is the most stable and present in terms of the system with the interregional transfers overcoming surpluses and deficit in regions.

- **Case B- Unit 7 Offline**

The generation loss as a result of the outage in Unit 7 is 900 MW in Western regions. The Western demand (2100 MW) is satisfied with the generation capacity of 1400 MW, that is a shortage by 700 MW (33.3%). The Southern region is compensated with a surplus of 550 MW (64.7 percent of its demand) and the Eastern region illustrates the additional 150 MW (7.1 percent of its demand). With the outage, the system still enjoys a full 100 percent overall demand coverage, however, additional dependence on interregional transfers to all rise to 700 MW (13.9 percent of total load). The spinning reserve capacity is 700 MW (13.8 % of the demand), but the share of such reserve is biased towards the South and it creates less flexibility of operations. Statistically, this scenario points out how the system latches on to Southern exports and how the Western grid is vulnerable since failure deters one-third of its total demand.

- **Case C- Unit 8 Offline**

With Unit 8 out of service, Western region will have only 1200 MW generation capacity to supply its 2100 MW demand translating to 57.1% sufficiency. This creates a 900 MW shortage (42.9 % of demand). The Southern region has excess capacity of 600 MW (70.6% of its demand) and the Eastern region has capacity of 300 MW (14.3% of its demand). Total interregional transfers are 900 MW (17.8% of system demand) making it the highest transfer reliance recorded. In most circumstances spinning reserve is at 900 MW (17.8% total demand) but due to the tie-lines being at saturated maximum transfer capacity, this reserve is practically limited. Statistically, this scenario demonstrates the precarious nature of the Western operations with the loss of a single unit resulting in almost 43 percent gap in the demand which puts the whole system right on the edge of its performance capabilities.

- **Case D - Increase of Load to 5700 MW**

With demand at 5700 MW, the total generation is maintained at 5050 MW and in this case generating a short change of 650 MW (11.4 percent of system shortage). Regionally, the Southern area can meet its requirement with large amounts of excess capacity (340 MW or 35.4 percent of its requirement). The deficit in the Eastern region is however 720 MW (30.4% deficit) as compared with the generation and demand of 1650 MW and 2370 MW, respectively. The Western area generates 2100 against a demand of 2370 MW giving a shortfall of 270 MW (11.4 percent shortfall). More importantly, spinning reserves are down to almost zero (0 per cent of system demand), they have run practically dry with no reserves left to cover any other contingencies. This situation lowers coverage to 88.6%, with the Eastern region having the lowest coverage of 55.4%.

Accordingly, the quantitative analysis in the four cases demonstrates the most important insights about operational resilience of the interconnected grid in Libya. In Cases A-C, coverage is restricted to 100%, even during outages, because of the non-decreasing representative growth factor, but drops to 88.6 percent in Case D, where the representative growth factor grows at a faster rate than the installed generation capacity. Cases B and C demonstrate the vulnerability of the Western region as unit outages result in deficits that cover 33-43% of Western demand, and hence their high reliance on interregional transfers. The proportion of the total demand affected by this transfer dependency will increase between Case A and C to a maximum of 17.8%. At the same time, the reserve margins become less effective, beginning at 8.9% in Case A and falling down to zero in Case D, there will be no operational buffer left to cover contingencies. Lastly, the magnitude of the deficit focus is highly felt in Case D as the Eastern region constitutes over 55 percent of the overall system deficit, which points to the necessity of focused capacity addition and reinforcement in the Eastern region.

Based on the quantitative study findings, it can be concluded that in Cases A and B as well as Case C, the system coverage stays unaffected by power exchange between the regions at 100 percent, whereas in Case D, the system coverage is only 88.6 percent since the sum of total loads (650 MW) exceeds the available power (700 MW). The western region is the most exposed with the coverage dropping to 66.7 percent when Unit 7 is out and deficit soars to 900 MW (42.9 percent coverage of demand) when unit 8 is out. The percentage reliance on interconnection slightly grows over time in each of the three Cases to 8.9 in Case A, 12.0 in Case B, and 17.8 in Case C, indicating the straining of the interconnection lines. In Case D, however, transmission capacity is insufficient. In Cases B and C operating reserve rises temporarily to 900 MW (17.8 percent of the load) but virtually evaporates with the additional load in Case D, breaking any emergency response margin. Lastly, the maximum deficit gap also falls in the Eastern Region in Case D, which alone suffers a gap of 720 MW (55% of the total gap), indicating a strong necessity to plan towards increasing production capacity in this region as in Table 5.

11. COMPARSION BETWEEN THE CURRENT STUDY AND RECENTLY STUDIES

This case study differs remarkably compared to the other reviewed studies *[1, 2, 7, 10, 13]* because it focuses on the real-world operational approach of the Libyan power system. This paper directly offers quantitative measure of system coverage, spinning reserves and transfer dependencies in several scenarios (A-D) that most theoretical models do not actually look into concrete grids.
The in-text citations to *[4]*, and *[5]* are referencing papers that are discussing using renewable energy and storage to

support unit commitment, but our study illustrates regional imbalances and weaknesses of a typical generation system lacking this backup flexibility. This difference is useful in demonstrating the vulnerability on practicability of non-diversified systems especially in developing world such as Libya.

Another addition is the clear quantification of vulnerability in the Western regions and concentration of deficit in the East, which has not been stated in the other reviews like *[6]* and *[8]*, which focus more on how solutions should be applied rather than what to address operationally. Demonstrating how shortages due to individual unit breakdown translate into demand shortfalls serving as a case to show that our research identified a level of systemic risk that purely algorithmic studies cannot identify (33-43 % demand shortfall).

In addition, our research is useful as it represents a baseline statistical framework that can be complemented with more sophisticated approaches to resilience, such as those advanced by recent research *[9]*, *[18]*. The means of statistics such as coverage ratios, reserves margins, and dependents in transfer, may be used in the future as input thresholds in the algorithm solution that may be provided toward fragile systems.

Lastly, global reviews *[21, 20]* also have a focus on the improvement of resilience and energy storage as the means toward achieving reliability. This study results strengthen this argument by proving empirically that without storage or additional reserve capacity, the Libyan grid cannot sustain growing demand (Case D, 88.6% coverage). This evidence-based gap underscores the urgency of capacity expansion in the Eastern region and investment in storage/renewables for long-term resilience.

Table 5. Comparative Statistical between study cases.

	Case A – Normal (5050 MW)	Case B – Unit 7 Offline	Case C – Unit 8 Offline	Case D – Demand 5700 MW
System Coverage (%)	100%	100%	100%	88.6%
Total Surplus/Deficit (MW)	0	0	0	-650
Transfer Dependency (% of Demand)	8.9% (450 MW)	13.8% (700 MW)	17.8% (900 MW)	Import needed (capacity capped)
Largest Regional Deficit (MW / % Demand)	East: -450 (21.4%)	West: -700 (33.3%)	West: -900 (42.9%)	East: -720 (30.4%)
System Spinning Reserve (MW / % Demand)	450 (8.9%)	700 (13.8%)	900 (17.8%)	0 (0%)

12. CONCLUSION

The Unit Commitment (UC) issue is quite crucial in the framework of the effective and risk-free running of power systems. It means choosing the mix of producing units that is the most affordable to meet the expected demand over a certain planning period while following a range of technical constraints. By means of a good UC system, one can significantly save running expenses and enhance grid efficiency. This paper aimed to investigate some well-known and innovative methods of problem solving including Lagrangian relaxation and dynamic programming as well as to go over their benefits and drawbacks. Though there are several methods now accessible, the development of computationally efficient algorithms that provide high-quality responses within limited runtimes remains a vital field of research. Incorporation of intelligent optimisation algorithms, especially those that balance speed, accuracy, and constraint handling, is increasingly important for the aim of extending UC practices in modern and future power systems. By evaluating the case study, it concluded that, under routine operations the power system functions dependably but requires maximum support from the Southern areas after major outages happen in Western units.

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The power system requires extensive power interchange and lowers spinning reserve margins after Unit 7 or Unit 8 experiences any outage. The system deficit reaches 650 MW when demand reaches 5700 MW because both the Eastern and Western regions lack sufficient power supply. The study reveals a critical need for balanced regional power capacities, additional emergency reserves and improved power grid reliability in the power system.

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