CHAPTER V
CO-OPTIMISED FRAMEWORK FOR COMBINED ELECTRICITY MARKET AND EMISSION MECHANISMS WITH COORDINATED DEMAND RESPONSE AND ANCILLARY SERVICES

5.1 Chapter Overview

This chapter presents a comprehensive evaluation of the novel integrated market-clearing framework to validate its performance and quantify its benefits in terms of economic efficiency, environmental outcomes, and grid security. This chapter empirically demonstrates the advantages of co-optimising energy, ancillary services, and demand-side flexibility within a unified market structure incorporating carbon pricing. The evaluation is conducted using the standard IEEE 30-bus test system, which serves as a benchmark for methodological validation. A range of simulation scenarios has been rigorously designed to test the model under various plausible conditions. These scenarios systematically vary key policy and operational parameters, including different carbon tax rates, tiered demand response (DR) incentive levels, and conditions of generator shortage, thereby allowing for a robust assessment of the framework's adaptability.

This chapter is the comparative analysis of different market-clearing strategies. The performance of the proposed integrated co-optimisation approach is benchmarked against a conventional sequential clearing mechanism. Furthermore, each clearing strategy is evaluated under two distinct schemes: a traditional generation-only case and the proposed DR-integrated case, which uniquely allows uncalled DR to serve as spinning reserve capacity. The results section provides a detailed analysis of key performance indicators, including total operational costs, reserve procurement costs, and system-wide carbon emissions. The findings reveal that the integrated DR scenario yields significant economic advantages, achieving cost savings of up to 6.1% and substantially reducing reserve procurement expenditures compared to conventional approaches. Critically, the analysis demonstrates that utilising DR as a co-optimised reserve resource enhances system flexibility and adaptability without adversely affecting environmental performance. The chapter concludes by discussing the implications of these findings and offering vital, policy-relevant insights to support the design of a scalable, economically efficient, and environmentally sustainable electricity market. Figure 5.1 illustrates the ISO's management of energy and reserves, implementation of carbon tax mechanism, and utilisation of active or standby demand response for real-time balancing, enhancing cost efficiency and environmental performance.

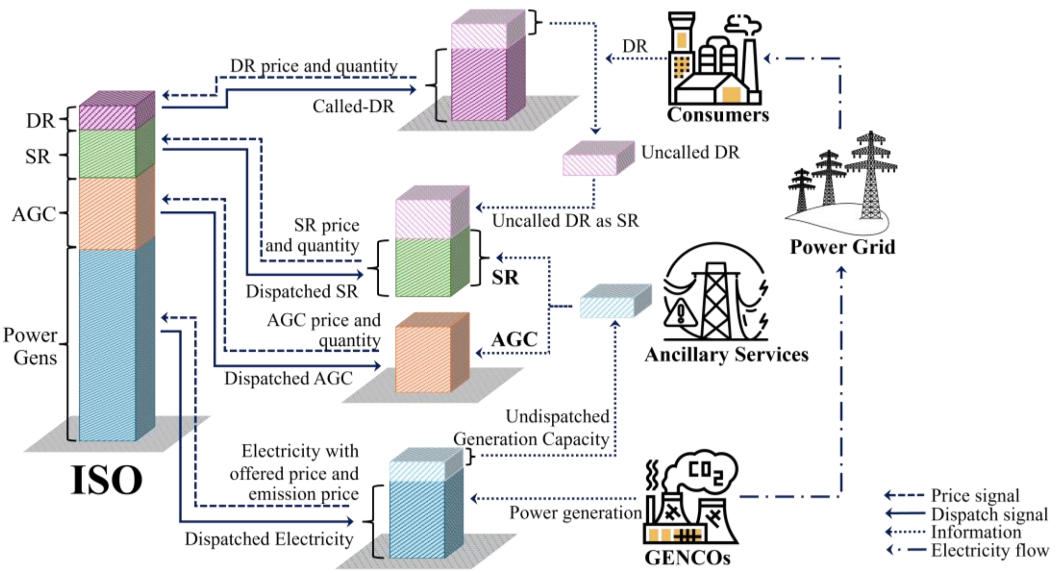

Figure 5.1 Schematic diagram of carbon-accounted optimal power dispatch and spot pricing

5.2 Mathematical Formulation

The proposed optimisation model minimises the total system operating cost, which includes CG, CCE, automatic generation control cost (CAGC), spinning reserve cost (CSR), and demand response cost (CDR). This formulation, containing both quadratic and linear components, is subject to constraints on power balance, generator and reserve capacity limits, and demand response. The calculations for CG and CCE are defined by Equations (3.13) and (3.14), respectively.

5.2.1 Cost of Automatic Generation Control

The cost of automatic generation control (CAGC) represents the financial cost incurred when generation units modulate their dispatch to provide frequency regulation and maintain grid security. The magnitude of this cost is influenced by the technical and economic characteristics of the generators, including their ramp rates and deviations from their optimal economic dispatch points. The CAGC, measured in dollars per hour ($/h), is determined by summing the costs from all participating units, where the cost for each unit i is the product of the market price for AGC service ($AGCP_i$ in $/MWh) and the amount of AGC capacity activated (AGC_i in MW):

$$CAGC(P_{G,i}) = \sum_{i=1}^{NG} AGCP_i \times AGC_i \ , \tag{5.1}$$

where $AGCP_i$ represents the price of automatic generation control at bus i ($/MWh) and AGC_i represents the activated automatic generation control capacity at bus i (MW).

5.2.2 Cost of Spinning Reserve

The spinning reserve utilisation is a critical component of power system reliability management, focusing on strategically activating reserve capacity to address emergent stability challenges. The economic aspect of spinning reserve services is defined by the cost structure of deploying this reserve capacity. Specifically, spinning reserve utilisation (SR_i) refers to the actual quantity of reserve capacity, measured in MW, that is dynamically activated during system contingencies. Meanwhile, the spinning reserve price (SRP_i) is expressed as the willingness to pay for activated services ($/MWh), at a designated bus i. The cost of spinning reserve (CSR) is calculated similarly to AGC, based on actual reserve deployed and its unit price defined as:

$$CSR(P_{G,i}) = \sum_{i=1}^{NG} SRP_i \times SR_i \ , \tag{5.2}$$

where SRP_i represents the unit price for spinning reserve ($/MWh), SR_i represents spinning reserve utilisation at bus i (MW).

5.2.3 Demand Response Cost

The DR cost incorporates incentive payments given to consumers who participate in load reduction under the DR programme. A progressive incentive system is used, with compensation increasing with the level of load reduction, expressed in \$/MWh, for participants in the demand response programme. For instance, early load reductions up to the first $\delta_{i,1}^{\max}$ MW receive \$ $R_{i,1}$ /MWh. Additional reductions beyond this threshold are rewarded at higher rates, at \$ $R_{i,2}$ /MWh and \$ $R_{i,3}$ /MWh, as shown in Figure 5.2. Therefore, the called-DR in step-based pricing, which represents the total cost incurred for reducing electricity consumption, can be described as follows:

$$CDR(\delta_{i,j}) = \sum_{i=1}^{ND} \sum_{j=1}^{NDR} R_{i,j} \times \delta_{i,j} \ , \tag{5.3}$$

subject to:

$$0 \le \delta_{i,j} \le \delta_{i,j}^{\max} \quad , i = 1,2,...,ND, \ j = 1,2,...,NDR \ , \tag{5.4}$$

where ND denotes the number of loads, NDR represents the number of pricing steps in the demand response program, $R_{i,j}$ is the price per unit of electricity reduction for step i by demand response participant j (\$/MWh), $\delta_{i,j}$ represents the amount of load reduction achieved within step i by demand response participant j (MW), $\delta_{i,j}^{\max}$ represents the maximum allowable reduction in step i by demand response participant j (MW).

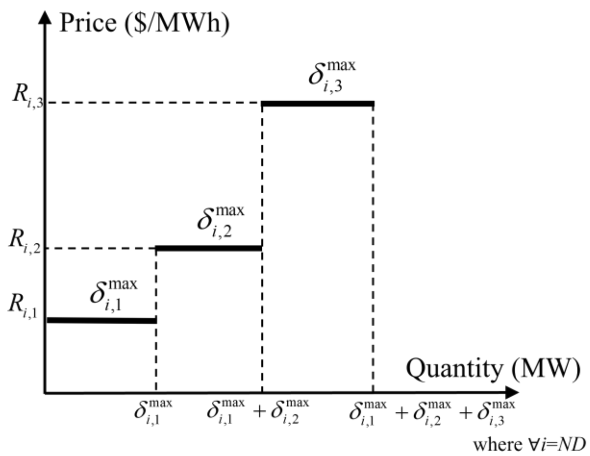

Figure 5.2 Incentive-based demand response with stepwise pricing

5.3 Objective Function and Study Cases

The proposed OPF framework simultaneously optimises economic generator dispatch and environmental objectives, the latter by limiting carbon emissions and incentivising renewable generation. System security is maintained through the integrated management of essential ancillary services, namely SR and AGC. The model internalises the cost of carbon emission, enabling it to identify dispatch portfolios that optimally balance operational expenditures against environmental externalities. Figure 5.3 demonstrates the effect of a demand response program on electricity market pricing and generation expenses. As power demand increases, the marginal cost of generation, which represents the aggregated generation cost, becomes apparent in the blue curve. Without a DR program, market-clearing prices and quantities are determined by the intersection of the demand curve and the aggregated generating cost, resulting in higher prices and quantities. However, implementing a DR programme reduces power demand and total electricity consumption. Market-clearing prices and amounts are reduced due to this decrease in demand. In addition, the market-clearing prices under the DR programme are calculated to reflect the associated DR costs, encompassing the financial incentives offered to participants.

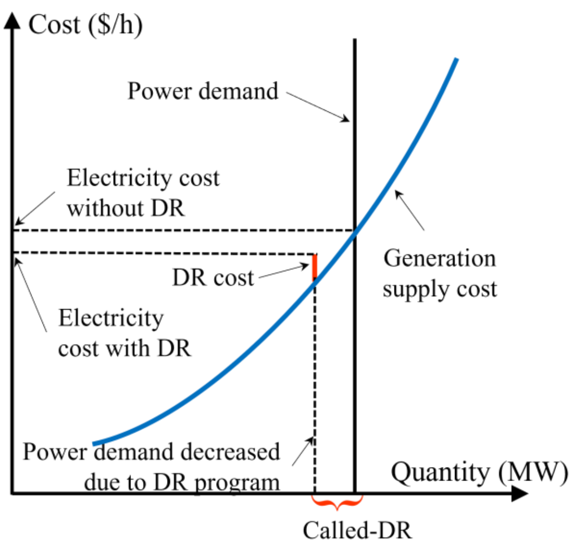

Figure 5.3 Demand response program on the electricity market pricing

To investigate the effects of DR integration, this chapter evaluates two market-clearing schemes: (1) a combined electricity-emission market without DR and (2) a combined electricity-emission market with DR. These schemes are assessed using both sequential and integrated clearing strategies, resulting in four distinct case studies: Sequential Market Clearing (SMC), Co-optimised Market Clearing (CMC), SMC with DR (SMC-DR), and CMC with DR (CMC-DR). Table 5.1 summarises the formulation of these four cases.

Table 5.1 Summary of market-clearing models

Scheme	**Market Model**	**Market Clearing Approach**		
		CM	***AS***	***DR***
1. Combined Electricity-Emission	SMC	Combined	Sequential	Without
	CMC	Combined	Co-optimised	Without
2. Combined Electricity-Emission with DR	SMC-DR	Combined	Sequential	Co-optimised
	CMC-DR	Combined	Co-optimised	Co-optimised

5.3.1 Scheme 1: Combined Electricity-Emission Scheme

Case 5.1a: Sequential Market Clearing (SMC)

In this case, energy dispatch is solved via quadratic programming-based OPF (QP-OPF), followed by separate linear programming-based (LP) procurement of ancillary services, reflecting traditional market operations. Hence, the primary objective function for this case can be formulated as follows:

minimise $$f_{5.1a,1}(x,u)=\left[\sum_{i=1}^{NG}CG(P_{G,i})+\sum_{i=1}^{NG}CCE(P_{G,i})\right]+\mu\cdot\left[g(x,u)\right]^2, \tag{5.5}$$

subject to:

$$\sum_{i=1}^{NG}P_{G,i}=\sum_{j=1}^{ND}P_{D,j}\ . \tag{5.6}$$

Sub-objective function can be described as follows:

minimise $$f_{5.1a,2}(x,u)=\sum_{i=1}^{NG} CAGC(P_{G,i})+\mu\cdot\left[g(x,u)\right]^2, \tag{5.7}$$

minimise $$f_{5.1a,3}(x,u)=\sum_{i=1}^{NG} CSR(P_{G,i})+\mu\cdot\left[g(x,u)\right]^2, \tag{5.8}$$

subject to:

$$\sum_{i=1}^{NG} AGC_i \geq \%AGCR\times\sum_{i=1}^{ND} P_{D,i}, \tag{5.9}$$

$$0\leq AGC_i\leq AGC_i^{\max},\quad i=1,2,...,NG, \tag{5.10}$$

$$P_{G,i}+AGC_i\leq P_{G,i}^{\max},\quad i=1,2,...,NG, \tag{5.11}$$

$$\sum_{i=1}^{NG} SR_i \geq \%SRR\times\sum_{i=1}^{ND} P_{D,i}, \tag{5.12}$$

$$0\leq SR_i\leq SR_i^{\max},\quad i=1,2,...,NG, \tag{5.13}$$

$$P_{G,i}+AGC_i+SR_i\leq P_{G,i}^{\max},\quad i=1,2,...,NG. \tag{5.14}$$

where $CG(P_{G,i})$, $CCE(P_{G,i})$, $CAGC(P_{G,i})$, and $CSR(P_{G,i})$ are formulated as shown in Equations (3.13), (3.15), (5.1), and (5.2), respectively.

<u>Case 5.1b</u>: Co-Optimised Market Clearing (CMC)

In this case, the proposed unified quadratic programming optimal power flow (QP-OPF) model co-optimises energy dispatch and ancillary services, thereby enabling operational synergies and enhancing cost-efficiency. So, the objective function for this case can be formulated as follows:

minimise $$f_{5.1b}(x,u)=\left[\sum_{i=1}^{NG}CG+\sum_{i=1}^{NG}CCE+\sum_{i=1}^{NG}CAGC+\sum_{i=1}^{NG}CSR\right]+\mu\cdot\left[g(x,u)\right]^2\ ,\tag{5.15}$$

subject to:

$$\sum_{i=1}^{NG}P_{G,i}+\sum_{i=1}^{NG}AGC_i+\sum_{i=1}^{NG}SR_i=\sum_{j=1}^{ND}P_{D,j}\ ,\tag{5.16}$$

and AGC and SR requirements are expressed in Equations (5.9)-(5.10) and (5.12)-(5.13), respectively.

5.3.2 Scheme 2: Combined Electricity-Emission with Demand Response Scheme

Case 5.2a: Sequential Market Clearing with demand response (SMC-DR)

In this case, a sequential optimisation approach is employed: an initial OPF-based dispatch is followed by a separate LP model for procuring DR and ancillary services. This decoupled methodology facilitates an assessment of its distinct market impacts. So, the primary objective function for this case can be formulated as follows:

minimise $$f_{5.2a,1}(x,u)=\left[\sum_{i=1}^{NG}CG+\sum_{i=1}^{NG}CCE+\sum_{i=1}^{ND}\sum_{j=1}^{NDR}CDR\right]+\mu\cdot\left[g(x,u)\right]^2,\tag{5.17}$$

subject to:

$$\sum_{i=1}^{NG}P_{G,i}=\sum_{j=1}^{ND}P_{D,j}-\underbrace{\sum_{i=1}^{ND}\sum_{j=1}^{NDR}\delta_{i,j}}_{\text{called DR}}\ .\tag{5.18}$$

Sub-objective function can be described as in Equations (5.7) and (5.8), subject to:

$$\sum_{i=1}^{NG}AGC_i\geq\%AGCR\times\left(\sum_{i=1}^{ND}P_{D,i}-\underbrace{\sum_{i=1}^{ND}\sum_{j=1}^{NDR}\delta_{i,j}}_{\text{called DR}}\right),\tag{5.19}$$

$$\sum_{i=1}^{NG} SR_i + \underbrace{\delta_{i,j}^{\max} - \sum_{i=1}^{ND}\sum_{j=1}^{NDR}\delta_{i,j}}_{\text{uncalled DR as SR}} \geq \%SRR \times \left(\sum_{j=1}^{ND} P_{D,j} - \underbrace{\sum_{i=1}^{ND}\sum_{j=1}^{NDR}\delta_{i,j}}_{\text{called DR}} \right), \tag{5.20}$$

and the active power generation limits of AGC are given in Equations (5.10) and (5.11), respectively. Likewise, the SR and active power generation limits of SR are used in Equations (5.13) and (5.14), respectively. The portion of DR capacity remains unused and is available as a reserve for system reliability.

<u>Case 5.2b</u>: Co-Optimised Market Clearing with DR (CMC-DR)

This case concurrently optimises energy, DR, and ancillary services within a single QP-OPF framework. Such a holistic formulation reflects an integrated, modern market design, thereby enabling the comprehensive utilisation of DR resources. Hence, the objective function can be formulated as follows:

minimise
$$f_{5.2b}(x,u) = \left[\sum_{i=1}^{NG} CG(P_{G,i}) + \sum_{i=1}^{NG} CCE(P_{G,i}) + \sum_{i=1}^{NG} CAGC(P_{G,i}) + \sum_{i=1}^{NG} CSR(P_{G,i}) + \sum_{i=1}^{ND}\sum_{j=1}^{NDR} CDR \right] + \mu \cdot \left[g(x,u) \right]^2, \tag{5.21}$$

subject to:

$$\sum_{i=1}^{NG} P_{G,i} + \sum_{i=1}^{NG} AGC_i + \sum_{i=1}^{NG} SR_i = \sum_{j=1}^{ND} P_{D,j} + P_{loss} - \underbrace{\sum_{i=1}^{ND}\sum_{j=1}^{NDR}\delta_{i,j}}_{\text{called DR}}, \tag{5.22}$$

and AGC and SR requirements are expressed in Equations (5.19) and (5.20), respectively. Moreover, variable limits are expressed in Equations (3.7), (5.10), (5.13), and (5.14).

A comparative analysis of Schemes 1 and 2 is conducted based on the total cost (TC), calculated as the summation of all cost components shown in Equation (5.23):

$$TC = \sum_{i=1}^{NG} CG(P_{G,i}) + \sum_{i=1}^{NG} CCE(P_{G,i}) + \sum_{i=1}^{NG} CAGC(P_{G,i}) + \sum_{i=1}^{NG} CSR(P_{G,i}) + \sum_{i=1}^{ND}\sum_{j=1}^{NDR} CDR(\delta_{i,j}). \tag{5.23}$$

For Scheme 1 (Cases 5.1a and 5.1b), which models a market without DR, the CDR component is inherently zero ($CDR = 0$).

5.4 Methodology

This chapter details the computational framework devised to evaluate the economic and environmental performance of the proposed market structures. The methodology is structured around the analysis of two primary schemes: (1) the combined electricity-emission scheme, detailed in Section 5.3.1, and (2) the combined electricity-emission with demand response scheme, presented in Section 5.3.2. To assess the impact of market design, each of these two schemes is implemented and compared using two distinct computational strategies: SMC and CMC. This structure yields four different case studies, including SMC, CMC, SMC-DR, and CMC-DR. The subsequent subsections will elaborate on the specific procedural steps and formulations adopted for each computational approach.

The control variables (x) are power generation, AGC, SR, and DR, which can be formulated as a quadratic function with linearised constraints. Therefore, the problem can be solved by QP. A standard quadratic programming problem can be expressed mathematically as follows:

$$\text{minimise} \qquad \frac{1}{2}\mathbf{x}^T\mathbf{H}\mathbf{x} + \mathbf{f}^T\mathbf{x}, \tag{5.24}$$

subject to:

$$\mathbf{A}\mathbf{x} \le \mathbf{b},\ \mathbf{A}_{eq}\mathbf{x} \le \mathbf{b}_{eq},\ lb \le \mathbf{x} \le ub. \tag{5.25}$$

5.4.1 Scheme 1: Combined Electricity-Emission Scheme Computation

(1) <u>SMC</u>: The SMC employs a sequential optimisation approach to separately address energy dispatch, ancillary service, and spinning reserves procurement. The procedural steps are as follows:

Step 1: Gather all required system data, including bus data, branch data, generator Variables, and system constraints.

Step 2: Perform a power flow analysis to determine the total active power generation $(P_{G,i})$ and demand $(P_{D,j})$.

Step 3: The control variables are $P_{G,i}$, AGC_i, and SR_i as follows:

$$\mathbf{x}_{P_G} = \left[P_{G,1},\ldots,P_{G,NG}\right], \tag{5.26}$$

$$\mathbf{x}_{AGC} = \left[AGC_1,\ldots,AGC_{NG}\right], \tag{5.27}$$

$$\mathbf{x}_{SR} = \left[SR_1,\ldots,SR_{NG}\right]. \tag{5.28}$$

Step 4: Minimise the combined CG and CCE as in Equations (5.5) and (5.6), using QP formulation in Equation (5.24) as follows:

$$\mathbf{H}_{5.1a,1} = \begin{bmatrix} 2A_1 & 0 & \cdots & 0 \\ 0 & 2A_2 & \cdots & 0 \\ \vdots & \vdots & \ddots & \vdots \\ 0 & 0 & \cdots & 2A_{NG} \end{bmatrix}_{NG\times NG}, \tag{5.29}$$

$$\mathbf{f}_{5.1a,1} = [B_1 \ldots B_{NG}]^T, \tag{5.30}$$

where:

$$\mathbf{x}_{5.1a,1} = \mathbf{x}_{P_G}, \tag{5.31}$$

$$A_i = a_i + C_{Tax}(\alpha_i \times 0.01^2),\; B_i = b_i + C_{Tax}(b_i \times 0.01),\; i = 1,\ldots,NG. \tag{5.32}$$

Step 5: Compare the sum of $P_{G,i}$ from the QP solution with the initial power flow results. If the difference exceeds 0.001, recompute the QP until convergence.

Step 6: Minimise CAGC solving for AGC_i using LP as in Equations (5.7), (5.9), (5.10), and (5.11).

Step 7: Minimise CSR solving for SR_i using LP as in Equations (5.8), (5.12), (5.13) and (5.14).

Step 8: Calculate total operation cost, as in Equation (5.23).

Step 9: Verify all results against system constraints, including power balance, AGC and SR requirements, and operational limits.

(2) CMC: The CMC simultaneously integrates energy dispatch and AS procurement within a single optimisation framework. The procedural steps are as follows:

Step 1: Gather all required system data.

Step 2: Perform a power flow analysis to determine the $P_{G,i}$ and $P_{D,j}$.

Step 3: Define the control variables are $P_{G,i}$, AGC_i, and SR_i as in Equations (5.26)-(5.28).

Step 4: Minimise the objective function, as in Equations (5.15) and (5.16), using QP as follows:

$$\mathbf{H}_{5.1b} = \begin{array}{ccc} \scriptstyle P_G & \scriptstyle AGC & \scriptstyle SR \end{array} \begin{bmatrix} \mathbf{H}_{5.1a,1} & \overbrace{0_{NG\times NG}} & \overbrace{0_{NG\times NG}} \\ 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NG} \\ 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NG} \end{bmatrix}_{3\cdot NG\times 3\cdot NG}, \tag{5.33}$$

$$\mathbf{f}_{5.1b} = [B_1 \ldots B_{NG} \;\; AGCP_1 \ldots AGCP_{NG} \;\; SRP_1 \ldots SRP_{NG}]^T, \tag{5.34}$$

where:

$$\mathbf{x}_{5.1b} = \left[\mathbf{x}_{P_G} \;\; \mathbf{x}_{AGC} \;\; \mathbf{x}_{SR}\right]. \tag{5.35}$$

Step 5: Verify that the optimised values satisfy the power balance constraint, reserve requirements, and operational limits for $P_{G,i}$, AGC_i, and SR_i. If any constraints are violated, refine the QP setup and resolve.

5.4.2 Scheme 2: Combined Electricity-Emission with Demand Response Scheme Computation

(1) SMC-DR: SMC-DR follows a sequential optimisation approach, incorporating DR explicitly in the process. The steps include:

Step 1: Gather all required system data.

Step 2: Perform a power flow analysis to determine $P_{G,i}$ and $P_{D,j}$.

Step 3: The control variables are $P_{G,i}$, AGC_i, SR_i and $\delta_{i,j}$ as in Equations (5.26)-(5.28) and

$$\mathbf{x}_{DR} = [\delta_{1,1} \ldots \delta_{ND,NDR}]\,. \tag{5.36}$$

Step 4: Minimise the combined CG, CCE, and CDR as in Equations (5.17) and (5.18) using QP as follows:

$$\mathbf{H}_{5.2a,1} = \begin{array}{c} \begin{array}{cc} P_G & \qquad \overbrace{\phantom{0_{NG\times NDR}}}^{DR} \end{array} \\ \begin{bmatrix} \mathbf{H}_{5.1a,1} & 0_{NG\times NDR} \\ 0_{NDR\times NG} & 0_{NDR\times NDR} \end{bmatrix}_{(NG+NDR)\times(NG+NDR)} \end{array} , \tag{5.37}$$

$$\mathbf{f}_{5.2a,1} = [B_1 \ldots B_{NG} \;\; R_1 \ldots R_{NDR}]^T , \tag{5.38}$$

where:

$$\mathbf{x}_{5.2a,1} = [\mathbf{x}_{P_G} \;\; \mathbf{x}_{DR}]\,. \tag{5.39}$$

Step 5: Compare the sum of $P_{G,i}$ from the QP solution with the initial power flow results. If the difference exceeds 0.001, recompute the QP until convergence.

Step 6: Minimise CAGC solving for AGC_i using LP as Equation (5.7), subject to as in Equations (5.10), (5.11), and (5.19).

Step 7: Minimise CSR solving for SR_i using LP as Equation (5.8), subject to as in Equations (5.13), (5.14), and (5.20).

Step 8: Calculate TC integrating DR as Equation (5.23).

Step 9: Verify all results against system constraints, including power balance with DR, AGC, and SR requirements and operational limits.

(2) CMC-DR: The CMC-DR adopts a fully integrated optimisation strategy incorporating DR into market-clearing. Procedural steps include:

Step 1: Gather all required data.

Step 2: Perform a power flow analysis to determine the $P_{G,i}$ and $P_{D,j}$.

Step 3: Define the decision variables are $P_{G,i}$, AGC_i, SR_i and $\delta_{i,j}$ as in Equations (5.26), (5.27), (5.28) and (5.36).

Step 4: Minimise the objective function as in Equation (5.21), subject to Equation (5.19), (5.20), and (5.22) using QP as follows:

$$\mathbf{H}_{5.2b} = \begin{array}{c} \begin{array}{cccc} \quad P_G \quad & \quad \overbrace{\quad\quad}^{AGC} \quad & \quad \overbrace{\quad\quad}^{SR} \quad & \quad \overbrace{\quad\quad}^{DR} \quad \end{array} \\ \begin{bmatrix} \mathbf{H}_{5.1a,1} & 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NDR} \\ 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NDR} \\ 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NG} & 0_{NG\times NDR} \\ 0_{NG\times NDR} & 0_{NG\times NDR} & 0_{NG\times NDR} & 0_{NDR\times NDR} \end{bmatrix}_{(3\cdot NG+NDR)\times(3\cdot NG+NDR)} \end{array}, \qquad (5.40)$$

$$\mathbf{f}_{5.2b} = [B_1 \ldots B_{NG} \;\; AGCP_1 \ldots AGCP_{NG} \;\; SRP_1 \ldots SRP_{NG} \;\; R_1 \ldots R_{NDR}]^T, \qquad (5.41)$$

where:

$$\mathbf{x}_{5.2b} = [\mathbf{x}_{P_G} \;\; \mathbf{x}_{AGC} \;\; \mathbf{x}_{SR} \;\; \mathbf{x}_{DR}]. \qquad (5.42)$$

Step 5: Verify that the optimised values satisfy the power balance constraint, reserve requirements, and operational limits for $P_{G,i}$, AGC_i, SR_i and $\delta_{i,j}$. If any constraints are violated, refine the QP setup and resolve the issue.

5.5 Simulation Results and Discussions

The proposed market-clearing framework is evaluated on the IEEE 30-bus test system to assess its performance in terms of cost efficiency, emission reduction, and system reliability under various market-clearing strategies and DR levels. The IEEE 30-bus system comprises 30 buses, 41 transmission lines, six generators, and 24 load buses. A baseline carbon tax of \$50/ton CO_2 is applied, while the requirements for AGC and SR are each set at 5% of the total active power dispatch. DR is implemented through a stepwise incentive structure, with incentive rates of \$2, \$4, and \$6/MWh corresponding to load reductions of 5 MW, 10 MW, and 15 MW, respectively. To examine the robustness of the proposed framework, additional sensitivity analyses are performed under varying generator availability conditions by systematically reducing the generation capacity of the Bus 2 generator $(P_{G,2})$ from 100% of its rated capacity to 75%, 60%, 50%, and 40%, simulating progressive capacity shortage scenarios. This subsection presents the simulation results from the IEEE 30-bus test system, analysing four market scenarios under two primary market schemes: the combined electricity–emission scheme (with and without DR). Each scheme is evaluated under both sequential (SMC and SMC-DR) and integrated (CMC and CMC-DR) clearing strategies. Simulations are conducted under progressively reduced generation availability at Bus 2, with $P_{G,2}$ outputs ranging from 100% to 40% of their maximum capacity.

The CMC consistently yields lower total operating costs compared with the SMC, particularly under conditions of limited generation availability as shown in Table 5.2. At 40% PG,2 capacity, the CMC approach achieves a 2.65% reduction in total system cost relative to SMC. Although SMC results in slightly lower emissions, the CMC scheme demonstrates greater stability in ancillary service procurement, especially in AGC and SR, thereby enhancing overall system security. Further improvements are observed when DR is incorporated, as summarised in Table 5.3. At 40% $P_{G,2}$ capacity, total operating cost decreases from \$966.01/h under SMC-DR to \$940.14/h under CMC-DR, representing a 2.68% cost reduction. The CMC-DR also eliminates the need for SR procurement by effectively utilising uncalled DR as reserve capacity, without compromising emission performance. The emission levels remain comparable between the sequential and integrated approaches, confirming that DR integration provides both economic and environmental benefits when co-optimised with other market components. Figure 5.4 illustrates the total cost performance across all simulation scenarios. DR-integrated strategies consistently yield lower system costs, while integrated clearing approaches outperform their sequential counterparts under all conditions. Among all configurations, CMC-DR delivers the most favourable outcomes in terms of cost reduction, reliability enhancement, and reserve optimisation. These findings substantiate the effectiveness of the proposed fully integrated market-clearing framework in co-optimising carbon pricing, ancillary services, and demand response to achieve sustainable, economically efficient electricity market operations.

Table 5.2 Comparison of combined electricity-emission scheme for IEEE 30-bus system

Variable	Scheme 1: Combined Electricity-Emission Scheme									
	Case 5.1a: SMC					Case 5.1b: CMC				
	$P_{G,2}$ *capacity (%)*					$P_{G,2}$ *capacity (%)*				
	100%	*75%*	*60%*	*50%*	*40%*	*100%*	*75%*	*60%*	*50%*	*40%*
$P_{G,1}$ (MW)	185.96	185.96	186.96	191.65	196.34	185.96	185.96	189.68	190	190
$P_{G,2}$ (MW)	49.71	49.71	48	40	32	49.71	49.71	43.36	35.36	27.35
$P_{G,5}$ (MW)	20.03	20.03	20.1	20.40	20.71	20.03	20.03	20.27	20.94	21.53
$P_{G,8}$ (MW)	15.00	15.00	15.48	17.72	19.98	15.00	15.00	16.79	21.69	26.11
$P_{G,11}$ (MW)	10.17	10.17	10.33	11.08	11.84	10.17	10.17	10.77	12.42	13.91
$P_{G,13}$ (MW)	12.00	12.00	12	12	12	12	12	12	12.46	13.94
AGC_1 (MW)	6.00	6.00	6	6	3.66	6	6	6	6	6
AGC_2 (MW)	4.64	4.64	0	0	0	4.64	4.64	4.64	4.64	4.64
AGC_5 (MW)	0	0	4.64	4.64	5	0	0	0	0	0
AGC_8 (MW)	0	0	0	0	1.98	0	0	0	0	0
AGC_{11} (MW)	0	0	0	0	0	0	0	0	0	0
AGC_{13} (MW)	4	4	4	4	4	4	4	4	4	4
SR_1 (MW)	4	4	4	2.35	0	4	4	4	4	4
SR_2 (MW)	0	0	0	0	0	0	0	0	0	0

Table 5.2 Comparison of combined electricity-emission scheme for IEEE 30-bus system (Continued)

Variable	**Scheme 1: Combined Electricity-Emission Scheme**									
	Case 5.1a: SMC					**Case 5.1b: CMC**				
	$P_{G,2}$ capacity (%)					***$P_{G,2}$ capacity (%)***				
	100%	***75%***	***60%***	***50%***	***40%***	***100%***	***75%***	***60%***	***50%***	***40%***
SR_5 (MW)	5	5	5	5	5	5	5	5	5	5
SR_8 (MW)	5.64	5.64	5.64	6	6	5.64	5.64	5.64	5.64	5.64
SR_{11} (MW)	0	0	0	0	0	0	0	0	0	0
SR_{13} (MW)	0	0	0	1.29	3.64	0	0	0	0	0
CG *($/h)*	800.24	800.24	800.22	801.62	805.55	800.24	800.24	800.72	804.26	810.70
CE *(t/h)*	0.348	0.348	0.349	0.358	0.368	0.348	0.348	0.354	0.354	0.354
CCE *($/h)*	17.38	17.376	17.464	17.91	18.400	17.376	17.376	17.714	17.700	17.688
$CAGC$ *($/h)*	113.08	113.08	117.72	117.72	131.4	113.08	113.08	113.08	113.08	113.08
CSR *($/h)*	128.43	128.43	128.43	134.31	143.72	128.43	128.43	128.43	128.43	128.43
TC *($/h)*	1,059.12	1,059.12	1,063.83	1,071.5	1,099.06	1,059.13	1,059.13	1,059.94	1,063.46	1,069.9

Table 5.3 Comparison of combined electricity-emission with demand response scheme for IEEE 30-bus system

Variable	Scheme 2: Combined Electricity-Emission with Demand Response Scheme									
	Case 5.2a: SMC-DR					Case 5.2b: CMC-DR				
	$P_{G,2}$ capacity (%)					*$P_{G,2}$ capacity (%)*				
	100%	*75%*	*60%*	*50%*	*40%*	*100%*	*75%*	*60%*	*50%*	*40%*
$P_{G,1}$ (MW)	183.23	183.23	183.93	188.72	193.41	185.76	185.76	189.45	194	194
$P_{G,2}$ (MW)	49.084	49.084	48	40	32	49.664	49.664	43.376	35.376	27.376
$P_{G,5}$ (MW)	19.854	19.854	19.899	20.210	20.515	20.018	20.018	20.258	20.575	21.208
$P_{G,8}$ (MW)	13.698	13.698	14.034	16.325	18.572	14.910	14.910	16.676	19.017	23.684
$P_{G,11}$ (MW)	10	10	10	10.614	11.371	10.136	10.136	10.732	11.521	13.095
$P_{G,13}$ (MW)	12	12	12	12	12	12	12	12	12	13.126
AGC_1 (MW)	6	6	6	6	6	6	6	6	6	6
AGC_2 (MW)	4.393	4.393	0	0	0	4.624	4.624	4.624	4.624	4.624
AGC_5 (MW)	0	0	4.393	4.393	4.393	0	0	0	0	0
AGC_8 (MW)	0	0	0	0	0	0	0	0	0	0
AGC_{11} (MW)	0	0	0	0	0	0	0	0	0	0
AGC_{13} (MW)	4	4	4	4	4	4	4	4	4	4
SR_1 (MW)	0	0	0	0	0.593	0	0	0	0	0
SR_2 (MW)	0	0	0	0	0	0	0	0	0	0

Table 5.3 Comparison of combined electricity-emission with demand response scheme for IEEE 30-bus system (Continued)

Variable	Scheme 2: Combined Electricity-Emission with Demand Response Scheme									
	Case 5.2a: SMC-DR					Case 5.2b: CMC-DR				
	$P_{G,2}$ capacity (%)					*$P_{G,2}$ capacity (%)*				
	100%	*75%*	*60%*	*50%*	*40%*	*100%*	*75%*	*60%*	*50%*	*40%*
SR_5 (MW)	4.393	4.393	4.393	4.393	3.800	0	0	0	0	0
SR_8 (MW)	0	0	0	0	0	0	0	0	0	0
SR_{11} (MW)	0	0	0	0	0	0	0	0	0	0
SR_{13} (MW)	0	0	0	0	0	0	0	0	0	0
δ_1 (MW)	5	5	5	5	5	0.38	0.38	0.38	0.38	0.38
δ_2 (MW)	0	0	0	0	0	0	0	0	0	0
δ_3 (MW)	0	0	0	0	0	0	0	0	0	0
CG ($/h)	783.09	783.09	783.05	784.26	788.01	798.95	798.95	799.41	802.28	808.39
CE (t/h)	0.343	0.343	0.344	0.353	0.363	0.347	0.347	0.354	0.363	0.363
CCE ($/h)	17.150	17.150	17.212	17.655	18.139	17.360	17.360	17.694	18.150	18.136
CAGC ($/h)	110.33	110.33	114.72	114.72	114.72	112.87	112.87	112.87	112.87	112.87
CSR ($/h)	35.146	35.146	35.146	35.146	35.146	0	0	0	0	0
CDR ($/h)	10	10	10	10	10	0.751	0.751	0.751	0.751	0.751
TC ($/h)	955.71	955.71	960.13	961.78	966.01	929.93	929.93	930.73	934.05	940.14

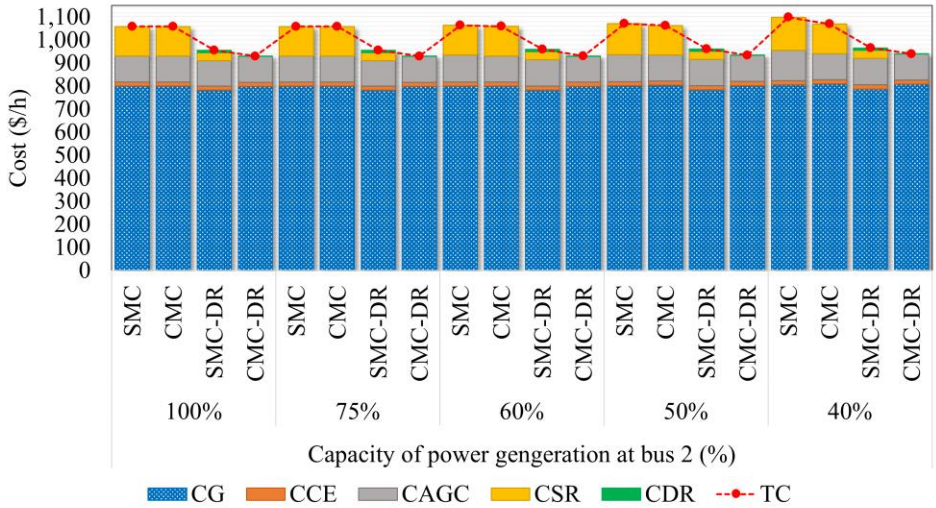

Figure 5.4 Comparison of cost across different scenarios under varying power generation capacity for IEEE 30-bus system

5.5.1 Sensitivity Analysis on Combined Electricity-Emission Scheme

This section investigates the influence of carbon pricing on system performance under the combined electricity-emission scheme (Scheme 1). The analysis evaluates how variations in the carbon tax rate affect total system cost (TC) and emission levels under two market-clearing strategies: the sequential market clearing (SMC) and the combined market clearing (CMC) approaches. The carbon tax rate is varied incrementally from \$10/ton CO_2 to \$90/ton CO_2, representing a wide range of potential policy scenarios for carbon regulation.

Table 5.4 summarises the outcomes of this sensitivity analysis. Increasing the carbon tax rate leads to a modest consistent reduction in total emissions, from 0.357 ton/h at the lowest tax level to 0.338 ton/h at the highest, indicating a gradual shift toward lower-emission generation units, even without the inclusion of demand response. This pattern underscores the effectiveness of carbon pricing in promoting cleaner generation dispatch. Conversely, total system cost rises steadily with increasing carbon tax rates in both SMC and CMC schemes. At \$10/ton, the TC is approximately \$1,046.5/h, whereas at \$90/ton, it reaches \$1,072.8/h, representing an overall increase of about 2.5%. Although the CMC approach consistently yields slightly lower costs than SMC across all tax levels, the results highlight the typical trade-off between emission reduction and operational expenditure associated with carbon pricing policies.

The carbon-emission component exhibits the greatest variation across tax levels, whereas the costs of AGC and SR remain constant at \$113.08/h and \$128.43/h, respectively. Notably, both SMC and CMC yield identical outcomes at all tax levels, indicating that in the absence of demand-side flexibility mechanisms such as DR, the advantages of integrated optimisation are minimal in terms of cost reduction when only carbon-related constraints are considered. These results imply that although carbon taxation leads to moderate emission reductions, its impact on total system cost is linear mainly, and the generation-only framework lacks sufficient operational flexibility to respond effectively to carbon pricing signals. Figure 5.5 illustrates the distribution of total cost components, including generation, emission, AGC, and SR costs, under five carbon tax levels within the combined electricity-emission scheme, comparing sequential and integrated clearing approaches. As the carbon tax rate increases, total cost rises gradually across both cases. However, the integrated clearing approach consistently maintains slightly lower or equivalent costs relative to the sequential method, reflecting enhanced coordination in reserve procurement and more efficient system operation.

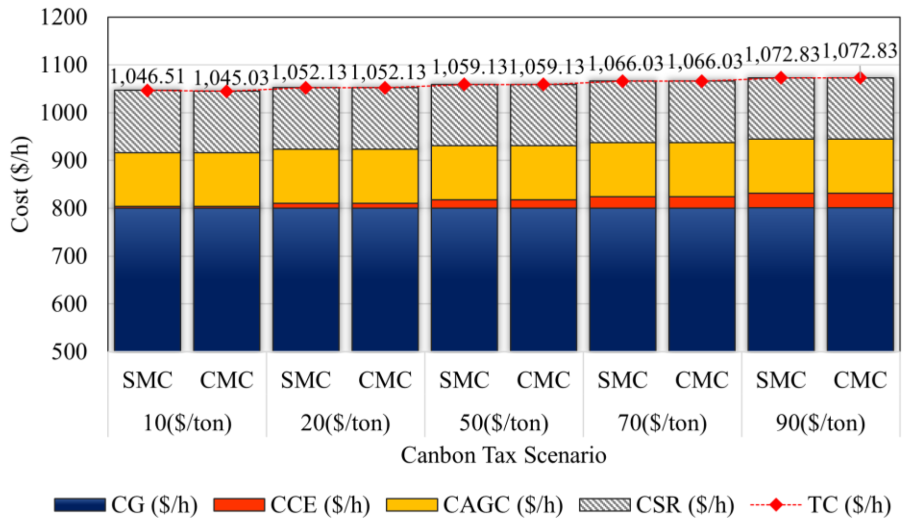

Figure 5.5 Impact of carbon tax on market-clearing costs in combined electricity-emission scheme

5.5.2 Sensitivity Analysis on Combined Electricity-Emission with Demand Response Scheme

This section investigates the influence of carbon pricing on combined electricity-emission with demand response scheme (Scheme 2). Table 5.5 presents the results of the sensitivity analysis conducted under the combined electricity-emission scheme with DR integration. The study explores the joint effects of varying carbon tax rates and DR incentive levels on overall system performance. Two market-clearing strategies, SMC-DR (sequential DR clearing) and CMC-DR (integrated DR clearing), are evaluated across nine scenarios corresponding to three DR incentive structures: [1, 2, 3], [2, 4, 6], and [3, 6, 9] \$/MWh.

The results indicate that CMC-DR consistently achieves lower or equal total costs than SMC-DR across all carbon tax levels. The cost advantage of CMC-DR becomes increasingly evident as the DR incentive level rises. For instance, at a carbon tax of \$90/ton, the total system cost in SMC-DR ranges from \$969.24/h to \$1,034.76/h, depending on the incentive level, whereas CMC-DR maintains a significantly lower range of \$943.24/h to \$943.99/h. Despite the higher DR payment rates, the CMC-DR framework preserves cost efficiency through more effective co-optimisation, selecting DR resources strategically to minimise overall system expenditure. Consequently, the DR cost (CDR) in CMC-DR is notably lower than in SMC-DR, reflecting superior utilisation of demand-side flexibility.

Emission reductions are moderate but consistent across all DR-inclusive scenarios, with average emission levels declining from approximately 0.357 t/h to 0.333 t/h as carbon tax rates and DR incentives increase. These results demonstrate the synergistic benefits of combining carbon pricing with incentive-based DR programs. The CMC-DR exhibits a stronger and more dynamic response to both carbon tax and DR price signals, effectively leveraging demand-side flexibility to reduce dependence on costly spinning reserves while maintaining cost-effectiveness under diverse policy conditions.

The sensitivity analysis confirms that carbon pricing alone produces limited impacts on system costs and emissions. However, integrating with structured DR incentives significantly enhances operational flexibility and economic performance.

The proposed integrated DR framework demonstrates strong robustness across varying policy parameters, offering a scalable, practical solution to improve the environmental and economic efficiency of electricity market operations. Figure 5.6 illustrates the distribution of total cost components under different combinations of carbon tax and DR incentive levels for the SMC-DR and CMC-DR cases. While SMC-DR is more sensitive to incentive variations, CMC-DR consistently achieves lower, more stable total costs, with notably reduced spinning reserve and DR procurement costs.

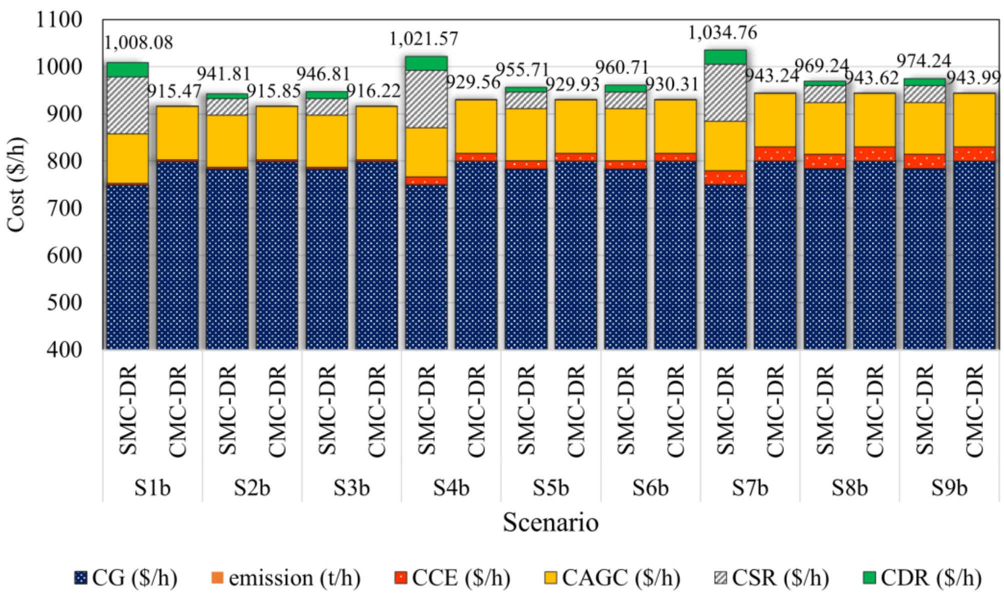

Figure 5.6 Combined impact of carbon tax and DR incentives on cost composition for combined electricity-emission with demand response scheme

Table 5.4 Sensitivity of carbon tax rates under the combined electricity-emission scheme for IEEE 30-bus system

Scheme 1: Combined Electricity-Emission Scheme								
Carbon tax ($/ton)	*Scenario*	*Case*	*CG ($/h)*	*CE (ton/h)*	*CCE ($/h)*	*CAGC ($/h)*	*CSR ($/h)*	*TC ($/h)*
10	S1a	SMC	799.950	0.357	3.574	113.076	129.916	1,046.515
		CMC	799.966	0.356	3.561	113.076	128.432	1,045.035
20	S2a	SMC	800.048	0.352	10.573	113.076	128.432	1,052.129
		CMC	800.048	0.352	10.573	113.076	128.432	1,052.129
50	S3a (Baseline)	SMC	800.245	0.348	17.376	113.076	128.432	1,059.129
		CMC	800.245	0.348	17.376	113.076	128.432	1,059.129
70	S4a	SMC	800.550	0.342	23.970	113.076	128.432	1,066.028
		CMC	800.550	0.342	23.970	113.076	128.432	1,066.028
90	S5a	SMC	800.935	0.338	30.385	113.076	128.432	1,072.828
		CMC	800.935	0.338	30.385	113.076	128.432	1,072.828

Table 5.5 Sensitivity of carbon tax and DR incentives under the combined electricity-emission with demand response scheme for IEEE 30-bus system

Scenario 2: Combined Electricity-Emission with Demand Response Scheme										
Carbon tax ($/ton)	*DR Incentive ($/MW)*	*Scenario*	*Case*	*CG ($/h)*	*CE (t/h)*	*CCE ($/h)*	*CAGC ($/h)*	*CSR ($/h)*	*CDR ($/h)*	*TC ($/h)*
10	**1,2,3**	S1b	SMC-DR	748.930	0.340	3.396	104.826	120.932	30	1,008.084
			CMC-DR	798.659	0.357	3.570	112.869	0	0.376	915.473
	2,4,6	S2b	SMC-DR	782.811	0.352	3.523	110.326	35.146	10	941.806
			CMC-DR	798.659	0.357	3.570	112.869	0	0.751	915.849
	3,6,9	S3b	SMC-DR	782.811	0.352	3.523	110.326	35.146	15	946.806
			CMC-DR	798.659	0.357	3.570	112.869	0	1.127	916.224
50	**1,2,3**	S4b	SMC-DR	749.121	0.334	16.693	104.826	120.932	30	1,021.572
			CMC-DR	798.952	0.347	17.360	112.869	0	0.376	929.556
	2,4,6	S5b (Baseline)	SMC-DR	783.088	0.343	17.150	110.326	35.146	10	955.709
			CMC-DR	798.952	0.347	17.360	112.869	0	0.751	929.932
	3,6,9	S7b	SMC-DR	783.088	0.343	17.150	110.326	35.146	15	960.709
			CMC-DR	798.952	0.347	17.360	112.869	0	1.127	930.307

Table 5.5 Sensitivity of carbon tax and DR incentives under the combined electricity-emission with demand response scheme for IEEE 30-bus system (Continued)

Scenario 2: Combined Electricity-Emission with Demand Response Scheme										
Carbon tax (\$/ton)	*DR Incentive (\$/MW)*	*Scenario*	*Case*	*CG (\$/h)*	*CE (t/h)*	*CCE (\$/h)*	*CAGC (\$/h)*	*CSR (\$/h)*	*CDR (\$/h)*	*TC (\$/h)*
90	**1,2,3**	S7b	SMC-DR	749.673	0.326	29.334	104.826	120.932	30	1,034.765
			CMC-DR	799.640	0.337	30.358	112.869	0	0.376	943.243
	2,4,6	S8b	SMC-DR	783.742	0.334	30.031	110.326	35.146	10	969.244
			CMC-DR	799.640	0.337	30.358	112.869	0	0.751	943.619
	3,6,9	S9b	SMC-DR	783.742	0.334	30.031	110.326	35.146	15	974.244
			CMC-DR	799.640	0.337	30.358	112.869	0	1.127	943.994

5.6 Conclusion

This study develops an integrated electricity market framework that jointly optimises generation dispatch, carbon pricing, ancillary services, and incentive-based DR. The proposed model, tested on the IEEE 30-bus system, demonstrates that integrated optimisation consistently outperforms conventional sequential market-clearing approaches regarding cost efficiency, system reliability, and environmental performance. In particular, the co-optimised scenario incorporating DR (CMC-DR) achieved the lowest total operating cost, reducing system expenditure by up to 6.1% compared with traditional generation-only models under generation shortage conditions. This improvement is primarily attributed to using uncalled DR capacity as spinning reserve, effectively minimising reliance on generation-based reserves without compromising reliability.

The simulation results also confirm the cost-effectiveness of implementing stepwise DR incentives. These incentives enable significant load reductions while maintaining economic efficiency. When combined with carbon pricing, DR further enhances emission-reduction outcomes, underscoring the synergies of integrating environmental and demand-side mechanisms. From a policy perspective, the findings advocate a transition from generation-centric market structures to more flexible, integrated frameworks. Such reforms would enable better coordination between energy, reserve, and environmental markets, supporting decarbonisation and operational efficiency.

This study demonstrates that an integrated operational approach is technically viable and economically advantageous. By co-optimising supply- and demand-side resources under carbon constraints, the framework offers a practical and scalable pathway for electricity market reform, enhancing system efficiency, environmental sustainability, and long-term energy security.