Emerging Electricity Markets: Including New Energy Storage Technologies & Integrating DERs via ISO-DSO Coordination

by

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Author's Declaration

This thesis consists of material all of which I authored or co-authored: see Statement of Contributions included in the thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Statement of Contributions

Anshul Goyal was the sole author for Chapters 1, 2, and 7 which were written under the supervision of Prof. Kankar Bhattacharya and were not written for publication.

This thesis consists in part of four manuscripts written for publication. Exceptions to sole authorship of material are as follows:

Research presented in Chapters 3 and 4:
The research works presented in these chapters were conducted at the University of Waterloo by Anshul Goyal under the supervision of Prof. Kankar Bhattacharya.

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Abstract

Most countries have set a vision of net-zero Greenhouse Gas (GHG) emissions by 2050; however, based on current trends, many of them are lagging in meeting the targets, even for 2025. Energy transition, shifting from fossil-fuel based to clean resources, is a critical step toward achieving Net-Zero Emission (NZE) targets, and is being explored worldwide. The ongoing effort to support the transition to a decarbonized system is to deploy large-scale Renewable Energy Sources (RES); but even after the remarkable increase in deployment of RES, it still seems impossible to achieve decarbonization targets. Various countries, including Canada, have pledged to achieve NZE grid by 2035 and system operators have developed their decarbonization pathways with target objectives and timelines to attain this goal. In this context, green hydrogen-based systems emerge as a potential zero-carbon solution to meet the CO_2 emission reduction targets.

The electricity sector is recognized as vital for energy sector transformation, in order to achieve NZE goals, as there are already low and emission free resources in this sector such as RES, hydro, etc., and it can easily integrate with other sectors (heat, transport, etc.) as part of the electrification drive. The continuously growing demand for electricity is a challenge to energy security, grid resiliency and results in exorbitant energy prices during peak demand periods. The intermittent nature of RES imposes limits on their use and their variability leads to imbalances between the grid demand and supply. To meet these challenges, the power system requires flexible resources, for which, various alternatives have been proposed including Distributed Energy Resources (DERs), Demand Response (DR) and Energy Storage Systems (ESSs), which seem to be the most promising ones. Also, there have been remarkable advancements in the arena of smart grid, which encourages consumers to deploy DERs and re-profile themselves as prosumers. Different regulating bodies and utilities worldwide are re-organizing their electricity markets to be future-ready with high-DER vision, and are developing coordination models between the Independent System Operator (ISO) and Distribution System Operators (DSOs) to integrate DERs and realize their true potential for the whole system (transmission and distribution).

This thesis first presents a novel, Green Hydrogen Systems (GHSs) integrated, Uniform Marginal Price (UMP)-based Day-Ahead Market (DAM) framework and the mathematical model for electricity market auction. The wholesale electricity market participation of GHSs, comprising electrolyzers, storage tanks and fuel cells, is examined considering their bids and offers for charging and discharging modes, respectively. To support transition toward achieving an NZE grid, the effects of inclusion of GHS in the DAM with different emission control strategies, such as emission cap and carbon pricing are examined. Two real systems with distinct characteristics, Alberta and Ontario provinces of Canada,

are considered. Subsequently, this thesis presents an extension of the GHS integrated UMP-based market model to Hydrogen-based Emission Free Resources (HEFRs) included Locational Marginal Price (LMP)-based DAM model by formulating appropriate mathematical model, complying with the existing market rules. Comprehensive case studies and sensitivity analysis are carried out to examine the impact of integration of HEFRs on market settlement, marginal prices and system emissions during normal, congestion and under RES uncertainties scenarios.

Next, this thesis presents a novel framework with new mathematical models that integrate DR and Battery Energy Storage Systems (BESSs) simultaneously in an LMP-based Multi-Settlement Market (MSM), i.e. a coordinated DAM and Real-Time Market (RTM). A new set of generator ramping constraints, developed from the DAM settlement, and referred to as Day-Ahead Load-Following (DALF) Ramp, are included in the RTM auction model. The performance of the mathematical models are tested on the IEEE 24-bus Reliability Test System (RTS) by carrying out various case studies and scenarios, uncertainty and sensitivity analyses. Effect of DR and BESS characteristics such as level of participation, initial State-of-Charge (SOC), discharge rate, etc. on market settlement is examined. The results demonstrate the merits of the proposed framework, and the impact of the DALF Ramp, DR and BESS inclusion in the MSM auction models on marginal prices, market settlement and system operation.

Finally, the thesis presents a new *Cooperation Algorithm* and a parallel-hierarchical framework for coupling the wholesale and retail electricity markets in order to facilitate the participation of DERs including small-capacity Behind-the-meter DERs (BTM-DERs), in a competitive and equitable manner. The detailed mathematical models of ISO-DSOs coordinated, wholesale and retail market settlements for day-ahead period are developed. The models are tested on the IEEE 24-bus RTS (wholesale market) and multiple 33-bus distribution systems (retail markets). Results demonstrate the effectiveness of the proposed framework over a centralized wholesale market in terms of computational time and over the sequential structure, in terms of DERs' increased participation, reduced market prices, congestion management, emissions reduction and overall system operation.

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ॐ हनुमते नमः॥

Om Hanumate Namah!

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List of Acronyms

BESS Battery Energy Storage System

BAU Business As Usual

BTM Behind-the-Meter

DALF Day-Ahead Load-Following

DAM Day-Ahead Market

DC-OPF DC Optimal Power Flow

DCR Discharge Rate

DR Demand Response

DOD Depth-of-Discharge

DER Distributed Energy Resource

DERA Distributed Energy Resource Aggregator

DLMP Distributed Locational Marginal Price

DSO Distribution System Operator

ESS Energy Storage System

ESTs Energy Storage Technologies

FERC Federal Energy Regulatory Commission

GAMS General Algebraic Modeling System

GHG Greenhouse Gas

GHS Green Hydrogen System

HEFR Hydrogen-based Emission-Free Resource

HtP Hydrogen-to-Power

HSS Hydrogen Storage System

ISO Independent System Operator

IFM In-Front-of-Meter

LCOE Levelized Cost of Energy

LMP Locational Marginal Price

LSEs Load Serving Entities

LDCs Local Distribution Companies

MCP Market Clearing Price

MIP Mixed-Integer Programming

MCS Monte-Carlo Simulation

MSM Multi-Settlement Market

NZE Net-Zero Emissions

PV Photovoltaic

P2G2P Power-to-Gas-to-Power

PtH Power-to-Hydrogen

PtH-HtP Power-to-Hydrogen-to-Power

PRD Price-Responsive Demand

RTO Regional Transmission Organization

RTM Real-Time Market

RTS Reliability Test System

RES Renewable Energy Sources

RDAM Retail Day-Ahead Market

SCUC Security Constrained Unit Commitment

SMD Standard Market Design

SMR Steam Methane Reformation

SR Spinning Reserve

SOC State-of-Charge

SCC Social Cost of Carbon

UMP Uniform Marginal Price

UC Unit Commitment

WDAM Wholesale Day-Ahead Market

Chapter 1

Introduction

1.1 Motivation

Carbon dioxide (CO_2) emissions from the energy sector increased by 321 Mt in 2022, exceeding the past years' and climbing to a new level above 36.8 Gt globally [1]. The largest contributors to this increase were from the electricity and heating sectors, raising concerns and a challenge to find innovative and sustainable solutions. Most countries have set a vision of net-zero Greenhouse Gas (GHG) emissions [2] by 2050; however, based on current trends, many of them are lagging in meeting the targets, even for 2025 [3]. The ongoing effort to support the transition to a decarbonized system is to deploy large-scale Renewable Energy Sources (RES); but even after the remarkable increase in deployment of RES, it still seems impossible to achieve decarbonization targets [4]. Also, the energy transition requires stakeholders to explore paths to switch from fossil fuel-based to clean resources, that presents opportunities and challenges. Various countries, including Canada, have pledged to achieve Net-Zero Emissions (NZE) grid by 2035 and system operators have developed their decarbonization pathways with target objectives and timelines to attain this goal [5, 6]. Decarbonization in the context of the power sector refers to limiting the GHG emissions from energy generation. Complete decarbonization of a sector is achieved when the net GHG emissions of the sector is zero, referred to as *carbon-neutral system* [2].

In this context, green hydrogen-based systems emerge as a potential zero-carbon solution to meet the CO_2 emission reduction targets. Green hydrogen is a flexible energy carrier with potential applications in several fields [7] and is expected to be a ground-breaking technology for a sustainable world [8]. However, in contrast to renewable electricity, there is still no provisions for market entry for green hydrogen systems [9]. Till date, deployment

of hydrogen-based technologies in the power system has been to a limited extent only, because of their low overall efficiency, high Levelized Cost of Energy (LCOE), limited scale of production of electrolyzers and fuel cells, and lack of government policies/incentives. However, with advancements in fuel cell technology and hydrogen storage methods, it is anticipated that by 2030 the LCOE for hydrogen will be at par with RES [7]. Furthermore, initiatives such as the (US) Inflation Reduction Act of 2022 (IRA 2022) [10] and the (US) Hydrogen Earthshot programme (*'111'* Hydrogen Shot) [11], and country-wise hydrogen strategies especially in Europe [12] and Canada [13], are attracting a lot of investors and industrialists to deploy hydrogen-based energy systems. Furthermore, hydrogen is economically more viable for long storage periods, since it has high energy storage capacity (highest energy unit per mass among other available storage options) [14]. It is anticipated that hydrogen can potentially help achieve a decarbonized economy.

The electricity sector is recognized as vital for energy sector transformation, in order to achieve carbon-neutrality goals, as there are already low and emission free resources in this sector such as RES, hydro, etc., and it can easily integrate with other sectors (heat, transport, *etc.*) within the electrification drive. High penetration of RES (especially solar and wind technologies) into the power system is being witnessed over the past decade and it is expected to keep increasing because of their decreasing costs, low/zero carbon footprint, and various initiatives by governments and regulating bodies [15]. Increasing penetration of RES and rising electricity demand under the electrification drive, introduces critical challenges in power system operation, planning and stability. The growing demand are continuously challenging the energy security, grid resiliency and results in exorbitant energy prices during peak demand periods. The intermittent nature of RES imposes limits on their use and their variability leads to imbalances between the grid demand and supply. To meet these challenges, the power system requires flexible resources to meet the fluctuations and maintain reliable grid operations, for which, various alternatives have been proposed including Distributed Energy Resource (DER), Demand Response (DR) and Energy Storage System (ESS)[1], which seem to be the most promising and easily configurable, for grid applications, since they offer fast ramping, quick-start ability and flexibility in both downward and upward responses [16, 17].

DR can be briefly defined as change in consumption patterns of customers over time in response to varying electricity prices [18]. Numerous research and studies indicate that deployment of DR services during periods of high prices (peak hours) can result in lower electricity prices for all consumers, irrespective of participating in DR programs [19–24]. In the PJM market, DR contributed 3.8% (6,568 MW) in delivery year 2021-22 and increased to 5.0% (7,066 MW) in 2022-23 as percentage of total PJM committed capacity

[1] In this thesis, energy storage resource is referred as energy storage system (ESS).

[25]. An amount of 5,586 MW was provided by DR services in 2022 in CAISO real-time market settlement [26]. Energy Storage Technologies (ESTs) are emerging as key resources and have the potential to contribute to various applications in power systems through seasonal storage, frequency regulation, demand shifting and peak shaving, voltage support, arbitrage/storage trades, congestion relief and infrastructure investment, black start and off grid applications [27]. Based on such important advantages that can be offered by ESTs, many researchers have explored various ESS technologies and their roles in tackling ongoing issues [28]. Additionally, with the Federal Energy Regulatory Commission (FERC) Order 841 [29, 30] and Order 2222 [31, 32] issued, there is a thrust to facilitate the integration of ESS and participation of Distributed Energy Resource Aggregator (DERA)s in various markets (energy, ancillary services and capacity). However, each ESS has its merits and challenges based on operational, physical and thermal characteristics. Hence, there is no *one-size fits all* solution. This leads to configuring different types of ESTs in the system to tackle the different problems in power system [28]. For example, the Compressed Air Energy Storage (CAES) facility is an attractive option for grid operation because of its bulk capacity, high efficiency, low operating and energy costs, and low emission [33,34]. Whereas, the dominant reasons for Battery Energy Storage System (BESS) to be widely accepted and deployed, in comparison to other ESTs are flexibility in installation, relatively high ramp rate and maturity of technology [35]. Despite significant amount of work being done related to DR and BESS involvement in electricity markets, still there are substantial aspects which are not explored yet. For example, many works considered their participation individually and in specific markets. The need to capture operational and physical characteristics of market participants in their cost functions as per market rules and correlated detailed models for Standard Market Design (SMD) structure are other aspects which have been not adequately considered in the reported DR and BESS models, which are essential for their proper participation.

Also, there have been remarkable advancements in the arena of smart grid, which encourages consumers to deploy DERs and re-profile themselves as *prosumers* [36]. Governmental acts such as (US) FERC Order 841 [29,30] and Order 2222 [31,32] are catalysts in accelerating DER deployment. The rapid growth of DERs, especially at the distribution level, pose both a challenge and an opportunity for the power system. The uncontrolled and unplanned adoption of DERs can strain the existing infrastructure and lead to question the operating practices of distribution utilities (discos/Load Serving Entities (LSEs)/Local Distribution Companies (LDCs)). Some of the main challenges are load balancing, time-sensitive peaks, bidirectional power flows, congestion management, volt-var compensation and resource visibility. On the other hand, DERs offer a chance to unlock flexibility, clean resources, power regulation, reserves, capacity and may assist in mitigating conges-

tion issues with optimal siting [37–39]. Different regulating bodies and utilities worldwide are re-organizing their electricity markets to be future-ready with high-DER vision, and are developing coordination models between the Independent System Operator (ISO) and Distribution System Operator (DSO)s to integrate DERs and utilize their true potential for the whole system (transmission and distribution) [38, 40–42]. Some jurisdictions have allowed the participation of DERs in the wholesale electricity market via aggregators (US FERC Order 2222) while others have explored their role by developing local energy markets (LEMs) (also referred as retail markets) or in terms of a transactive energy market (based on peer-to-peer trading) [39, 43–45]. The framework of aggregator-based market integration of DERs is still undergoing development stage to establish an effective mechanism for better utilization of DERs. Whereas, the retail and transactive energy markets primarily utilize DERs at the distribution level. Globally, various pilot projects are being carried out to examine different ISO-DSO coordination models; EU SmartNet project in Europe [46], six different cooperation schemes in UK [47] and FERC Order 2222 aggregator-based participation in wholesale market in US [48]. The benefits and demerits of these approaches have been examined by researchers without reaching a conclusion on which method yields an effective utilization of DERs. Another challenge is the magnitude and extent of information exchange between the ISO and DSOs considering the privacy concerns of DERs [37]. Most of the currently reported coordination schemes can be grouped as follows:

- DERs depend on marginal bid/offer of aggregator, for clearance in the wholesale electricity market
- Hierarchical structure, in which DSOs respond to the wholesale market Locational Marginal Price (LMP)s at coupling buses, thereby, limiting the true potential of DERs.

The centralized ISO managed wholesale market wherein the DERs and distribution networks are integrated within the same market settlement model is not a workable option due to its large computational effort, privacy concerns of DERs and practical scalability issues associated with large real systems [49]. Thus, there is a need to explore innovative and implementable coordination schemes that exploit DERs services optimally and re-define the roles of the entities (ISO and DSOs) involved.

From the above discussions, it is evident that there is a need to understand the techno-economic impacts and develop mechanisms for including different DERs, DR and ESSs (mainly, BESS and Hydrogen Storage System (HSS)) in various types of electricity markets. There is also an urgent need to understand and develop a framework for effective coordination between the ISO and DSOs to facilitate market participation of small-scale

DERs. This thesis proposes appropriate frameworks and models for enabling the effective integration of different DERs and ESTs into electricity markets to meet the requirements of the present day complex power system and to contribute to achieving the carbon neutrality targets.

1.2 Literature Review

1.2.1 Hydrogen-based System Integration in Electricity Markets

Hydrogen is gaining a lot of attention from researchers, investors, energy sector participants and policymakers due to its potential of being a low-carbon energy carrier and its applications in several fields [7]. In [8], a solar-based Electric Vehicle (EV) charging station with hydrogen integration, as an energy storage alternative, is developed. The model considered energy and exergy-based thermodynamic analysis for performance evaluation. The authors examined two operational periods: (a) hydrogen production using electrolyzer during daytime via solar-based station, and (b) power generation through hydrogen fuel cells during low output periods of solar energy. The results demonstrate the relationship between hydrogen production, Photovoltaic (PV) panel area and EV charging station capacity. Despite incorporating thermodynamic aspects and green electricity production, the developed HSS model is not suitable for electricity market applications because it does not include any appropriate cost or bid/offer structure or model.

The authors in [50] examined the techno-economic aspects of coupled RES and hydrogen-based energy systems. The impact of inclusion of hydrogen energy in the grid-connected system toward power smoothing is examined, considering RES uncertainty. Optimal sizing of electrolyzers and Proton-Exchange Membrane (PEM)-type fuel cell is proposed based on the Particle Swarm Optimization-Chemical Reaction Optimization Algorithm (PSO-CROA) technique. While in [51], decarbonization of three coupled energy sectors, namely electricity, heating/industrial and transport are examined using numerical optimization techniques. Hydrogen production from electrolysis and fossil fuels with Carbon Capture Storage (CCS) is considered in view of sector coupling. And paper [52] presented a multivariate coupled economic model for a hydrogen system wherein RES coupled with off-peak electricity are considered for hydrogen production. A scheme is proposed therein, to determine the range of off-peak electricity consumption hours. The economic model takes into account the cost of carbon related to off-peak electricity utilization. All these works have examined the role of HSS either for power smoothing in the grid due to presence of RES or for analyzing its impact on decarbonization in multiple sectors. However, none of

them specifically proposes any framework or model that enables HSS to participate as a decoupled, individual participant in wholesale electricity markets.

Reference [53] proposed a green Hydrogen Credit (HC) system coupled with a Carbon Credit (CC) system for green hydrogen trading in the international market. The model takes into account hydrogen economics, life cycle and other aspects such as transportation. However, the illustrated framework is basic and needs to be comprehensively developed for practical implementation in electricity markets particularly. In [14], a Power-to-Gas-to-Power (P2G2P) system for green electricity production through hydrogen and RES was modeled. The P2G2P system was integrated into an existing microgrid (Baja, California) to evaluate its performance. The LCOE was used as a criterion for examining the feasibility of the hydrogen system. The analysis shows that the capital cost of P2G2P system components (electrolyzer, hydrogen tanks and fuel cells) needs to be reduced by 50%, for this technology to be economically viable and competitive. Nevertheless, the authors believe that the LCOE of the P2G2P system will follow the same pattern as for RES and BESS, *i.e.*. with the increased adoption and bulk production of P2G2P system components; the costs will decrease. The work in [14] discusses a specific study only; while the operational aspects can affect the overall system mechanism, which was not considered.

Some research works [54, 55] investigated the integration of hydrogen into energy systems, focusing on blending into natural gas with the concept of integrated electricity-gas systems. These works evaluated the reliability of the integrated systems with hydrogen. However, these studies did not examined the role of hydrogen-based systems in the electricity markets. In [56], the performances of BESS and HSS are evaluated for a single dwelling application with PV installation. The results demonstrate that BESS allows more PV energy to be utilized by the load as compared to the HSS, mainly due to the lower round-trip efficiency of the latter. It was illustrated that storage installations assisted in minimizing the daily gap/mismatch between demand and PV supply. The model presented was limited to a single dwelling application and commercial aspects like capital and operational costs are not taken into account in this work. Reference [57] analyzes the environmental and economic benefits of consuming energy from the grid for hydrogen production when RES is unavailable. The paper introduces a new metric/cost function *LCOH&E*, defined as the addition of Levelized Cost of Hydrogen (LCOH) and carbon-dioxide emission cost for hydrogen production. The case study highlights the benefits of using the proposed metric over LCOH for periods when RES are not obtainable for hydrogen generation. However, the thermodynamic aspects and operational constraints of HSS components are not evaluated.

Reference [58] evaluated the economic viability of hydrogen storage and BESS (Li-ion) in Poland. The operating profits and net present values for both kinds of storage technologies were compared wherein it was concluded that based on current cost metrics and

efficiencies of both technologies, BESS was more profitable as compared to hydrogen storage systems for short-term operations due to their higher efficiency and lower cost. However, based on decarbonization pathways released by different system operators globally and governmental initiatives (as discussed earlier), there is a need for alternative sources of energy in addition to BESS for achieving a decarbonized economy wherein hydrogen is considered to be a promising technology and is projected to be an essential part of the emissions reduction plan and the decarbonized supply mix of the future [5, 6, 59].

Many works have explored the role of hydrogen in decarbonization, through their integration in hybrid systems for smoothing RES intermittency or scheduling the hydrogen production process and hence its load [60]. The impact of power-to-gas process (electrolyzer aspects) on gas and electricity markets were considered in [61]. Some earlier works focused on hydrogen storage and transportation [61] while others analyzed the hydrogen-to-power aspects and proposed optimal sizing of PEM-type fuel cells [50]. In summary, most of the works explored the role of hydrogen sub-processes in providing grid services, but only independently, and not in a comprehensive manner, while neglecting their physical and operational attributes, assuming them non-bidding market entities. FERC Order 841 requires the physical and operational characteristics of ESSs participating in electricity markets as discrete market participant, and Order 2222 outlines the DERs' minimum sizing criteria to be met for wholesale market participation; which have been mostly not considered in the reported works.

1.2.2 DR and BESS Participation in Electricity Markets

With the advancement of smart grids, release of FERC Order 745 [62] and establishment of electricity markets, the participation of consumers offering DR services has been continuously increasing. DR programs have been adopted and offered by many countries and utilities across the world, in which every market has its unique features and specific attributes [63–68]. DR options practiced currently can be broadly classified in two ways: (a) Price-Responsive Demand (PRD) bids, and (b) Curtailment-based DR offers [69]. It is expected that this kind of interaction would further scale-up with the availability of technology and enabling policies/agreements. In [70], the authors propose an Energy Management System (EMS) for minimizing the energy cost of a household or a small business, which uses the rolling window technique to interact on an hourly basis. Although, the proposed model is effective from a customer point of view, it is not appropriate for examining the role of DR inclusion in wholesale electricity markets.

In [19], a stochastic model was developed to schedule Spinning Reserve (SR) provision by DR resources in wholesale electricity market. The proposed model was formulated as

a two-stage stochastic Mixed-Integer Programming (MIP) problem. The first stage is a network-constrained Unit Commitment (UC) while the second stage takes into consideration security constraints for each scenario. Monte-Carlo Simulation (MCS) approach is implemented to simulate random scenarios of generating units and transmission line outages. The benefits to DR providers in the ancillary service demand response program of ISO are evaluated. However, the proposed model examines the participation of DR in providing reserves only. DR deployment in a co-optimized energy-SR market is not evaluated. DR has been investigated in [20,21] to provide reserve offers in a joint energy-reserve market design. The proposed model is formulated as a mixed-integer optimization program and the results show the benefits of including demand-side reserve offers on social welfare. However, the work examines the role of DR for reserve services only, and not in energy market. Whereas, in [22], a bidding framework for DR services in Day-Ahead Market (DAM) is proposed considering customers' preferences. Despite considering customers' preferences, the proposed model examines the role of DR in energy market only, and not in reserve market. In [23], the impact of PRD shifting bidding on congestion and LMP in pool-based DAM is investigated. The proposed model considers the power system network constraints and AC power-balance equations. The results shows that the use of PRD bidding mechanism leads to reduction in peak LMPs and helps in congestion management. However, the proposed model do not take into consideration UC constraints.

Reference [71] presents a framework and a price-based self-scheduling model for DR aggregators to offer multiple contracts and services in DAM. Four types of DR contracts are considered, namely load curtailment, load shifting, utilizing ESSs, and utilizing on-site generation. Though the framework involves multiple services by DR, however constraints such as customers' preferences and DR role in reserve service are ignored. In [72], a co-optimized energy and SR day-ahead market design is proposed with DR participation. The model considers the load recovery periods while scheduling and clearing the forward market. The authors propose that the load reduction period shall be followed by a load recovery period. Hence, the recovery consumption needs to be taken into account for the adequate balance. However, the proposed model could be more effective if various DR scenarios taking into account customers' behavior were considered. In [73], a comprehensive overview of frameworks and programs for DR and ESS in North American electricity markets are discussed. DR participation modalities in each ISO can be categorized by procurement mode, participation time-frame, operational domain, and program type, as summarized in Table 1.1 [63–67].

Reference [74] presented a model for BESS co-located with a wind facility to participate in day-ahead and real-time electricity markets. The sizing of BESS was determined using 1-year historical data of wind generation and electricity prices from Mid-Continent

Table 1.1: Summary of DR Programs in Different ISOs in US [73]

ISOs	DR Programs	Min. size	Min. reduction	Trigger	Response time	Compensation
NYISO	DADRP	1 MW	1 MW	Price-based	2 hrs	DA LMP
	DSASP	1 MW	1 MW	Price-based	2 hrs	Respective reserve market clearing price
	EDRP	100 kW	100 kW	Extreme emergency operating conditions	15 min-2 hrs	Maximum of real-time zonal LMP or 500 $/MWh
	ICAP	100 kW	100 kW	Extreme emergency operating conditions	2 hrs	Maximum of real-time zonal LMP or 500 $/MWh
PJM	Economic DRP	0.1 MW (energy), 1 MW (reserve)	0.1 MW (energy), 1 MW (reserve)	Price-based	1 hr (energy), 5-10 min (reserve)	LMP for energy/ reserve market clearing price
	Emergency DRP	100 kW	100 kW	Extreme emergency operating conditions	1-2 hrs	Maximum of real-time zonal LMP or 500 $/MWh
ISO-NE	RDR	100 kW	100 kW	Price-based	5 min-1 hr	Maximum of real-time LMP or 50 $/MWh
	RPR	100 kW	100 kW	Extreme emergency operating conditions	5 min	Maximum of real-time LMP or 50 $/MWh
	DA Load Response	100 kW	100 kW	Price-based	30 min	LMP bid price: 50 $/MWh (min) - 1000 $/MWh (max)
MISO	DRR Type-II	100 kW	100 kW	Price-based	5 min-2 hrs	LMP
CAISO		100 kW (energy), 500 kW (reserve)	100 kW (energy), 100 kW (reserve)	Price-based	10 min, 15 min or 1 hr	LMP

Independent System Operator (MISO). BESS integrated Uniform Marginal Price (UMP)-based [75] and LMP-based [35] markets which co-optimized energy and SR in the day-ahead settlement were reported. The papers proposed a cost function for BESS based on its degradation, and corresponding bid/offer structures for it to participate in the markets. The papers noted increase in social welfare and the important role of BESS in flexibility provisions compared to a case with no BESS. Moreover, inclusion of BESS reduced the energy and SR prices. However, the above works did not consider the presence of RES, and the market framework considered DAM only, not examining the aspects of an Multi-Settlement Market (MSM), in particular, real-time operation. Reference [76] presented a framework for scheduling and controlling of BESS, deployed for multiple services simultaneously. In the first phase of the proposed algorithm, the allocation of BESS power and energy capability to each service (operation-scheduling) were determined. In the second phase, different services were deployed into the grid in real-time.

In [77], BESS was considered as a price-taker participant in DAM and Real-Time Market (RTM), in which BESS owner aimed to maximize its profit while exposed to price uncertainty. Reference [78] proposed a two-stage stochastic bi-level programming to determine the optimal size and site of BESS using signals from Distributed Locational Marginal Price (DLMP)s. References [79–81] investigated the role of BESS in different electricity markets as price-taker/price-maker and few references [82,83] implemented machine learning algorithms to evaluate BESS participation in markets. Reference [84] modeled BESS degradation by considering the discharge cycle of the BESS exclusively; however, the con-

sideration of degradation is absent from its cost function. Whereas, references [85, 86] proposed bidding strategy considering battery cycle life and its participation in day-ahead energy, spinning reserve, and regulation markets. However, these works did not take into account crucial aspects of BESS operation, including degradation from discharge rates and Depth-of-Discharge (DOD), within the BESS cost function frameworks.

1.2.3 ISO-DSO Coordination

In the conventional grid, the aggregators' (also referred as *agents* or *retailers* in different regions and jurisdictions) role was limited to aggregating the loads and submitting buy bids to the wholesale market. However, with the transition to smart grids, and integration of DERs and grid-scale DR, RES and BESS, *etc.*, they also participate in the wholesale market by submitting supply offers. Increased interest in DERs, technology advancements and consequent increased deployment of Behind-the-Meter (BTM)-DERs led to the new role of aggregators, and hence the need for formulating appropriate market designs where these resources can participate [38, 42]. In [87], various methodologies have been reviewed to integrate DERs into different level markets (wholesale and retail; [88, 89]), and it noted that most of the works pertaining to BTM-DERs have considered two approaches, as briefly described below:

- Direct participation in wholesale markets (operated by ISO) through aggregators, while satisfying the capacity limit criterion.
- Participation in retail markets operated by DSOs; no participation in the wholesale markets.

The merits of the above approaches have been examined by researchers without a conclusion on which method yields a more accessible and competitive market for BTM-DERs to participate.

Reference [42], examined the DER capabilities, their roles and official definition set by regulating bodies, considering market access and competition. It highlighted the need for establishing detail standards to avoid market entrants from undermining competition. The retail and wholesale markets are mostly *sequentially coupled*, wherein these two markets are considered to be one following other *i.e.* one market is solved considering at upper-level optimization problem and the other market at lower-level [90–95]. References [96–98] explored different roles of the DSO ranging from network management to independent

market operator and various models of ISO-DSO coordination varying from no involvement (decoupled) to different levels of coupling. These roles could be broadly classified as non-strategic DSO/decoupled markets, price-taker DSO, price-maker DSO and single centralized ISO managed. Several studies [89, 99–103]evaluated the impact of coupled operation of transmission and distribution systems, implementing sequential (hierarchical) coordination approaches.

Reference [99] proposed an algorithm for ISO-DSOs coordination for restoration of the transmission and distribution systems after an event, and method to utilize DERs capability for voltage regulation. In [104], the DSO was considered to manage distribution congestion only, considering the European electricity market structure. In [105], considers load aggregators in wholesale markets and DR provisions for controllable loads at the retail level. The first approach of direct participation (as discussed earlier) is considered in their work, but BTM-DERs are only limited to DR provisions. Similarly, [106] presents a decentralized hierarchical framework based on transactive energy control to balance electric vehicle charging loads locally through DERs; limiting their participation to the need of electric vehicle requirement only. In [107], a hierarchical power management model is proposed for cooperation among various microgrids and the wholesale market through a utility mediator. In [108], a framework for maximizing the agent's profit by sequential coupling of the two markets was considered. Reference [109] presents a sequential operational framework for wholesale and retail markets in the presence of a DSO, which interacts with the wholesale market by submitting an aggregated bid after settling the retail market. This is a sequential, bottom-up approach in contrast with the top-down approach reported in [108]. Reference [110] presents an interaction model between wholesale and retail markets for residential controllable thermal loads. The model integrated the optimization sub-problems of ISO, retailer and residential consumers in a single framework. The models in [111] and [112], presented a day-ahead retail market considering variable generation and utilization constraints of distributed RES.

1.2.4 Discussion

From the literature review, it can be noted that several works have been proposed for analyzing the environmental and economic impact of hydrogen systems. Some works examine their integration with renewables in microgrids or in single dwelling applications. However, while most of the works consider the emission, cost, coupling with RES and carbon capture, they neglect the operational and physical characteristics of a Green Hydrogen System (GHS) and its components. Some works suggest the participation in hydrogen

markets for low carbon hydrogen production and their deployment for multiple applications. However, there are no reported works, to the best of the author's knowledge, that proposes a framework or model for participation of GHSs in wholesale electricity markets. Thus, there is need to develop new frameworks which enable Hydrogen-based Emission-Free Resource (HEFR)s[2], *i.e.,* green hydrogen-based loads, storage and generation, as bidding participants in electricity markets in an equitable manner like other market entities, complying to the existing market rules. It is anticipated that HEFRs will assist in achieving NZE grid by reducing system emissions, in stabilizing energy prices, in reducing RES curtailment, in improving grid resiliency by providing flexibility and overall effective system operation.

From the presented literature review and discussions, it can be inferred that DR and BESS have proved to be important assets for improving grid operations. While previous works have examined their roles individually, in specific markets or simultaneous involvement in DAM, they have not considered the simultaneous participation of DR and BESS in an LMP-based MSM. Some previous works explored the role of DR to provide frequency regulation, system security and SR while neglecting their potential to offer services in the energy markets. Some works neglected the UC constraints and customers' preferences, while other works that considered the participation of DR in energy-cum-SR markets, but did not examine the benefits of simultaneous participation of DR and BESS. In the case of BESS, several works explored their participation in a system with RES, but neglecting their full potential as an individual market participant. Some works did not consider the effect of BESS attributes such as DOD and Discharge Rate (DCR), which makes the BESS model incomplete. On the other hand, works that incorporated these BESS attributes, considered them individually in LMP markets or with DR in UMP markets for a single-settlement system. To the best of the author's knowledge, the simultaneous participation of DR and BESS, in an LMP-based MSM is yet to be explored. The authors envisage that their simultaneous inclusion would result in reduction of energy market prices, more flexibility to system operators and enhanced grid reliability in the context of a modernized grid; as each resource has its own benefits and limitations.

Also, earlier works implementing MSM framework have considered the cleared schedule of generators from DAM as input to the RTM for its settlement. That means, all 5-min RTM settlement intervals within an hour were settled with the same DAM cleared dispatch of that hour. This assumption compromised the RTM model accuracy as it did not capture the ramp effect within an hour. The reported models also did not utilize the resulting 5-min ramp up/down schedules for balancing the real-time deviations between demand and

[2]In this thesis, the terms green hydrogen system (GHS) and hydrogen-based emission-free resource (HEFR) are used interchangeably.

supply, which resulted in need for additional resources to be dispatched in the RTM. These additional dispatches and consequently, additional cost and emissions, in the RTM could have been avoided if there was a suitable mechanism to include the effect of DAM 1-hour ramp into RTM settlement intervals. Thus, the RTM model needs to be appropriately modified to include the 5-min ramp in the FERC's SMD structure.

From a review of the literature, it is noted that most of the research works explored the penetration of DERs in the power grid, wherein the clearance of BTM-DERs was either dependent on the marginal cost curve of the aggregator or on the *ex-ante* wholesale LMP. Such mechanisms, although encouraged the participation of BTM-DERs, did not achieve their large-scale market penetration. Also as per FERC Order 2222, any DER or DERA participating in the wholesale market must bid/offer a minimum capacity of 100 kW. Consequently, small-capacity DERs have to be represented by aggregators and their individual bid/offer is camouflaged within the aggregator's bid curve; the wholesale market does not have the opportunity to utilize/clear the cheaper DERs. On the other hand, the centralized ISO managed wholesale market is computationally involved especially for real large systems and needs significant details and network information; which makes it an unfavourable choice in practicality. Thus, there is a need to explore new and effective mechanisms and develop appropriate frameworks for equitable participation of DERs, especially BTM-DERs. It is envisaged that the coupling of wholesale and retail markets in a combination of parallel (simultaneous) and hierarchical (sequential) settlements and enhanced coordination between ISO and DSOs will overcome the above issues and result in equitable opportunity for DERs to participate in the markets.

1.3 Research Objectives

Based on the presented literature review and discussions, it is noted that there is a need to examine the participation of emerging DERs, DR, BESS and HSS in electricity markets and to develop innovative coordination scheme between the ISO and DSOs for their effective utilization. To this effect, appropriate frameworks and mathematical models are required and accordingly the main objectives of the present research are the following:

- Develop a generic market framework to integrate GHSs in the wholesale electricity markets with the inclusion of different emission control strategies, such as emission cap and carbon pricing, to explore their role in achieving an NZE grid. The two real systems, Alberta and Ontario provinces of Canada, are considered to examine the benefits of the proposed framework.

- A comprehensive mathematical model to integrate GHSs in an UMP-based DAM will be formulated considering the physical, operational and energy arbitrage characteristics of GHS components. The proposed model will take into account the minimum size criteria as per FERC Order 2222 and energy arbitrage and market constraints inspired by FERC Order 841. Investigate the impact of GHS participation in DAM on market settlement attributes such as dispatch schedules, Market Clearing Price (MCP) profiles and system emissions.

- Extend the GHS (also referred to as HEFR) integrated UMP-based market model to LMP-based DAM model by inclusion of appropriate network constraints. Comprehensive case studies and sensitivity analysis are carried out to examine the impact of integration of GHSs on market settlement, LMPs and system emissions during normal, congested and RES uncertainties scenarios.

- Develop a generic framework and detailed mathematical models for LMP-based, loss included, multi-settlement wholesale electricity markets for 24-hour ahead DAM scheduling and 5-min ahead RTM dispatch, considering simultaneous participation of DR and BESSs, incorporating consumers' bid/ DR offer structures and BESS cost models based on DOD and DCR; complying with FERC Order 745 and Order 841.

- Formulate novel and realistic ramp constraints of generators, referred to as Day-Ahead Load-Following (DALF) Ramp, to take into account the contribution of resulting 5-min ramp availability from the cleared DAM generators schedules of each hour while settling of the RTM. Evaluate the effect of DALF Ramp constraints on RTM settlement (prices and dispatch). Also examine the contribution of the DALF Ramp to market attributes, such as RTM efficiency, vis-a-vis the case without it. Examine the impact of operational and physical characteristics of DR and BESS participants, such as their level of participation, initial State-of-Charge (SOC), DCR, etc. on the market settlements and overall dispatch through detailed sensitivity analyses.

- Develop a novel ISO-DSOs Cooperation Algorithm through exchange of minimal information on marginal prices and availability of cheap surplus energy resources at different market levels (wholesale and retail) to establish competitive and accessible (including BTM-DERs) wholesale-retail coupled electricity markets.

- Formulate detailed mathematical models for wholesale and retail market settlements to implement the proposed, interactive parallel-hierarchical, ISO-DSO coordinated framework considering comprehensive market constraints, DERs operational constraints and their inter-relationship constraints.

- Examine and compare the performance of the proposed framework in facilitating increased BTM-DERs penetration *vis-a-vis* the sequential structure. Examine the scalability of the proposed framework considering ISO's simultaneous coordination with multiple DSOs and compare the computational efficiency of the framework *vis-a-vis* the centralized ISO managed wholesale market.

1.4 Outline of the Thesis

The rest of the thesis is organized as follows:

- Chapter 2 presents key definitions of terminologies referred and an overview of the relevant background topics for the proposed research including electricity markets, DR, ESTs (in particular detail the BESS and HSS) and coordination schemes between ISO and DSOs.
- Chapter 3 presents a market framework to integrate GHSs in the UMP-based DAM with different emission control strategies, such as emission cap and carbon pricing. Detailed simulation case studies and analyses are presented considering two real systems, Alberta and Ontario provinces of Canada.
- Chapter 4 presents a modified mathematical model to integrate GHSs in an LMP-based DAM, considering appropriate network constraints.
- Chapter 5 presents a novel coordinated framework involving participation of DR and BESS in an LMP-based MSM (DAM+RTM). Detailed mathematical models for the proposed market design are formulated. Further, in order to validate the proposed model, multiple case studies under different scenarios are demonstrated in detail.
- Chapter 6 presents detailed mathematical models for wholesale and retail market settlements to implement the proposed, interactive parallel-hierarchical, ISO-DSOs coordinated framework considering comprehensive market constraints and DERs operational constraints are presented. Both the wholesale and retail market models are developed for day-ahead time horizon. Comprehensive case studies are demonstrated to show the performance of the proposed approach.
- Finally, Chapter 7 presents the main conclusions and contributions of this thesis, and identifies some directions for future research work.

Chapter 2

Background

2.1 Nomenclature

Sets & Indices

i, k	Buses, $i \in I$.
e	BESS, $e \in E$.
j	Generators (Gen), $j \in J$.
q, t	Time (hour), $q \in Q$.
h	Blocks of consumer bids, $h \in N_{CB}$.
n	Blocks of Gen offers, $n \in N_{GO}$.
l	Index for segments in piece-wise linear approximation, $l \in L$.

Parameters

C^D	Demand bid price, \$/MWh.
C^G	Gen energy offer price, \$/MWh.
$C^{SU/DN}$	Gen start-up/shut-down cost, \$.
$C^{ch/Dch}$	BESS charging/discharging bid/offer price, \$/MWh.
C^{BESR}	BESS SR offer price, \$/MWh.

a, b, c, d	BESS cost coefficients.
$\overline{P}^{D}$	Demand bid quantity of consumer, MW.
$\overline{P}^{G}$	Gen offer quantity for energy, MW.
$\overline{SOC}, \underline{SOC}$	BESS SOC upper/lower limits, p.u.
$\overline{P}_{ch/Dch}$	Maximum BESS charging/discharging power limits, MW.
$\eta^{ch/Dch}$	BESS charging/discharging efficiency, %.
B	Element of susceptance matrix, p.u.
g	Real part of the admittance of line (i, k), p.u.
α	Slope of the lth segment (or block) of the linearized voltage angle difference relative to the nodes i and k.
$\pi^{E/SR}$	Price of energy/SR market at time t, \$/MWh.
$N_{max}^{hyd,EL}$	Maximum number of hydrogen moles produced by the electrolyzer, mol.
$\eta^{hyd,EL/FC}$	Efficiency of electrolyzer/fuel cell, %.
LHV^{hyd}	Minimum thermal energy content of hydrogen, MW/mol.
$P_{max}^{hyd,EL}$	Maximum power of the electrolyzer, MW.
$P_{min}^{hyd,EL}$	Minimum power of the electrolyzer, MW.
Pr_{max}^{hyd}	Maximum pressure of the hydrogen storage tank, Pa.
Pr_{min}^{hyd}	Minimum pressure of the hydrogen storage tank, Pa.
$P_{max}^{hyd,FC}$	Maximum power generated by the fuel cell, MW.
$P_{min}^{hyd,FC}$	Minimum power generated by the fuel cell, MW.
$N_{max}^{hyd,FC}$	Maximum number of hydrogen moles consumed by the fuel cell, mol.
T^{hyd}	Average temperature of hydrogen, K.
V^{hyd}	Volume of the hydrogen storage tank, m^3.
$\Re$	Constant of gases, $JK^{-1}mol^{-1}$.

Variables

P^D	Demand cleared, MW.
P^G	Gen offer cleared for energy, MW.
$P^{ch/Dch}$	BESS charging/discharging power, MW.
P^{BESR}	BESS SR cleared, MW.
$E^{ch/Dch/SRC}$	BESS charging/discharging/SR energy, MWh.
DCR	BESS discharge rate, p.u.
SOC	BESS SOC, p.u.
w	1, if Gen energy offer cleared, 0 otherwise.
U, V	1, if Gen start/shut-down, 0 otherwise.
X	1, if demand bid cleared, 0 otherwise.
$Z1, Z2$	1, if BESS charging/discharging, 0 otherwise.
P^{loss}	Power loss in the transmission line between buses i and k, MW.
δ	Voltage angle, radian.
$P^{hyd,EL}$	Power consumed by the electrolyzer, MW.
$H^{EL/FC}$	1, if HSS charging/discharging, 0 otherwise.
$N^{hyd,EL}$	Number of hydrogen moles produced by the electrolyzer, mol.
Pr^{hyd}	Pressure of the hydrogen storage tank, Pa.
$N^{hyd,FC}$	Number of hydrogen moles consumed by the fuel cell, mol.
$P^{hyd,FC}$	Power generated by the fuel cell, MW.

2.2 Introduction and Key Definitions

Some key definitions of the terminologies and governmental policies referred in this thesis are presented at the outset, in this section. In Section 2.3, different types of electricity markets classified based on levels, operational time horizons and pricing schemes with mathematical models are discussed. In Section 2.4, the role of DR participation in electricity markets is described. This is followed by a discussion on new and emerging ESTs (BESS & HSS) and their participation in electricity markets in Section 2.5. In Section 2.6,

an overview of different coordination schemes between the ISO and DSOs are presented. Finally, Section 2.7 summarizes this chapter.

- *NZE*: "refers to balancing anthropogenic GHG emissions released into the atmosphere with removals of these emissions over a specified period" [2].
- *Prosumer*: is defined as "an energy user that can consume and produce energy through the use of RES, and either store the surplus energy for future use or engage in trade with interested energy customers in smart grid" [39, 113].
- *DR*: is defined as "changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" [18].
- *ESS*: is defined as "a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid" [29, 30].
- *DERs*: "are small-scale power generation or storage technologies (typically from 1 kW to 10,000 kW) that can provide an alternative to or an enhancement of the traditional electric power system. These can be located on an electric utility's distribution system, a subsystem of the utility's distribution system or behind a customer meter. They may include electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage or electric vehicles and their charging equipment" [32].
- *DERA*: is "an entity that aggregates one or more DERs for purposes of participation in the capacity, energy and/or ancillary service markets of Regional Transmission Organization (RTO)/ISOs" [114].
- *ISO*: "is an independent, federally (or as appropriate) regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system" [115].
- *DSO*: is an entity that "conducts physical dispatch of the distribution system to facilitate market access for DERs and may also undertake DER-related commercial activities" [42].
- *FERC Order 745*: addresses the compensation for DR resource participation in the organized wholesale energy markets. This rule requires "each RTO and ISO to pay

a DR resource for its services at the market price for energy (LMP) when the DR resource can balance supply and demand as an alternative to a generation resource and dispatch of the demand response resource is cost-effective" [62].

- *FERC Order 841*: facilitates the participation of ESS in RTO and ISO operated markets such as capacity, energy and ancillary service markets [29, 30]. This rule "requires each RTO/ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of ESSs, facilitates their participation in the RTO/ISO markets" [30].

- *FERC Order 2000*: established the minimum characteristics and functions for being an RTO, with the aim of promoting efficiency in the wholesale electricity market and reliability in the electricity supply with the lowest price possible [116, 117].

- *FERC Order 2222*: removes barriers preventing DERs from competing on a level playing field and enables them to participate in the electricity markets (capacity, energy and ancillary services markets) run by regional grid operators [31, 32]. It authorized RTO/ISOs to establish DERA as a type of market participant, with minimum size requirement of 100 kW, and outline coordination schemes among system operators, DERAs, distribution utility and retailers [48].

2.3 Electricity Markets

Electric industry restructuring led to the emergence of electricity markets around the world. Previously, a single utility operator oversaw generation, transmission, and distribution, ensuring energy provision across the entire service area. Tariffs were determined through regulatory processes rather than market dynamics, aiming to cover production costs and capital expenditures. Deregulation of the electric power industry resulted in the emergence of companies offering unbundled electrical services and a clear division between generation, transmission, and distribution, fostering competition through various market mechanisms. While transmission remains a regulated monopoly to guarantee fair access for all market participants, the concept of "retail competition" encompasses full market liberalization, transmission unbundling, regulated network access, and open electricity trading [118, 119]. According to economists, the markets are one of the finest methods to trade any commodity, including electricity.

An electricity market can be generally defined as a mechanism to trade electricity among various market participants or players [118]. Different kinds of markets are practiced across

the world to meet several system requirements, such as energy, regulation, capacity and ancillary services [119]. However, with the transition to smart grids, and integration of RES and ESTs, many other system requirements have to be captured along with the earlier ones. In an energy market, the objective is to maximize the social welfare while ensuring that the demand is matched with power supply, subject to a set of operating constraints [120]. An MCP is determined, which forms the basis for calculating payments by consumers, earnings by suppliers and congestion hedging [70].

There are several mechanisms for electricity trading such as bilateral contracts, power pools, power exchange or a combination of them [121]. Bilateral contract markets involve settlement among parties usually through a negotiation process, and without a central entity. Whereas, power pools are settled by a central-clearing entity, wherein buyers and sellers submit their energy bids and offers respectively. The pool determines the market settlement: prices, demand cleared and generation schedules and dispatch based on an auction mechanism [118]. With the progress in these organized markets and release of FERC Orders 888/889, the ISO was formed as the central, independent body to manage and operate the competitive electricity markets [122].

2.3.1 Multi-Settlement Market: Day-Ahead and Real-Time Markets

The MSM framework essentially refers to the settlement of the DAM one day ahead of actual operation, followed by dispatches settled through an RTM at close to real-time, typically 5-minute ahead. It has been reported that the MSM framework can reduce the vulnerability of price fluctuations in RTM and limit the exercise of market power by participants, and also has been adopted within the SMD of USA, as per FERC Order 2000 [116, 117]. In an MSM, the participants secure prices in the DAM, which then acts as a hedge against real-time price volatility.

The DAM is settled for each hour of the next operating day, that determines the MCP for each zone/node (in an LMP market) or for the system as a whole (in a UMP market) [123]. The market participants submit their respective bids and offers the day before, by a certain time as specified by the ISO. The outputs of the DAM model comprise the UC decisions, scheduled dispatches of winning generators, cleared consumers' demand, market prices (locational/uniform) and congestion rents/charges related to binding transmission lines, for each hour of the next day [17, 119]. For the LMP markets, the market prices and other DAM results are calculated using optimization algorithms with the objective to maximize social welfare considering a set of operational constraints [118, 124]. Typically

these models are equivalent to the well-known Security Constrained Unit Commitment (SCUC) problems [125]. The DAM prices and schedules are financially and contractually binding to all market participants.

The RTM, also sometimes known as balancing market, is settled as close to real-time typically 5-minute to 15-minute ahead [123]. The market participants submit their respective bids and offers for real-time energy imbalance and for ancillary services. The consumers pay at RTM rates for any demand exceeding their DAM schedules and receive payments at RTM rates for load curtailments in real-time *vis-à-vis* their DAM schedules. Likewise, the gencos receive payments at RTM rates for any generation increase in real-time as compared to their DAM dispatch schedules and pay at RTM rates for any generation decrease in real-time *vis-à-vis* their DAM dispatch schedules [17, 118, 119].

The energy markets considered for present studies are for short term, day-ahead and real-time (balancing) market. The DAM is settled for each hour of the next operating day typically 24-hour ahead, while the RTM is settled as close to real-time, typically 5-minute to 15-minute ahead [126].

2.3.2 Wholesale and Retail Electricity Markets

In the restructured electric power system, a wholesale market provides a platform wherein the bulk trade of electricity is carried out, either in a pool structure or through a bilateral/multilateral contract [118, 119]. The pool-type wholesale market is operated and/or settled by a Market Operator (MO). In North American electricity markets (Canada and USA), which is the focus of the studies presented in this thesis, the market operations and settlement functions are undertaken by the ISO or the RTO [122]. The functions of an ISO may include facilitating transactions and market operation, ensuring reliability, security of system operation, energy auction, generation dispatch, system security & control, provision for ancillary services, etc. in different operational time-frames, depending upon jurisdictions and regulations being followed [117, 127].

In a wholesale market, different market participants such as gencos, retailers, discos / LSEs / LDCs, large consumers, DERAs, etc. submit their respective buy bids and/or supply offers for trading energy, grid services, etc., typically at transmission level in a competitive framework. Upon receipt of the bids and offers, the ISO performs the market settlement and releases the outcomes such as MCP, dispatch schedules and other associated market attributes based on the market under consideration [128–130].

Conventionally, the retailers played a vital role in bridging the gap between the wholesale market and end-users. The energy flow was unidirectional from transmission to dis-

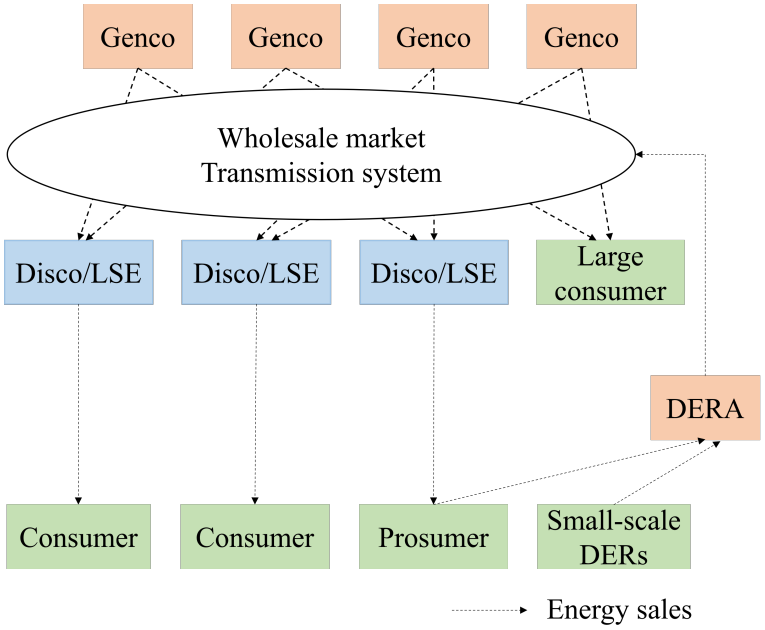


Figure 2.1: Wholesale electricity market competition structure [118, 119]

tribution and the discos' / LSEs' / LDCs' role was primarily to operate the distribution network. With the advent of a smart grid, as consumers are being transformed to *prosumers* and there has been significantly increased deployment of DERs at the distribution level, leading to emergence of the DSOs to manage and operate the retail electricity markets [131].

Figures 2.1 and 2.2 illustrate the structure of wholesale and retail competition electricity markets [118, 119], including DERA (with the release of FERC Order 2222).

2.3.3 Pricing Schemes: Uniform and Locational Marginal Prices

Electricity markets are classified in different ways based on various criteria. One of the classifications is based on pricing schemes which broadly categorizes into UMP and LMP [126, 132]. In UMP or single-price markets, there is one price (referred to as MCP) determined for the entire market. The MCP is obtained by a merit order algorithm where all participating consumers' bids are stacked in decreasing order of prices and all participating generators' offers in increasing order. The point of intersection of the demand and supply curves corresponds to maximum social welfare and hence, the MCP is ob-

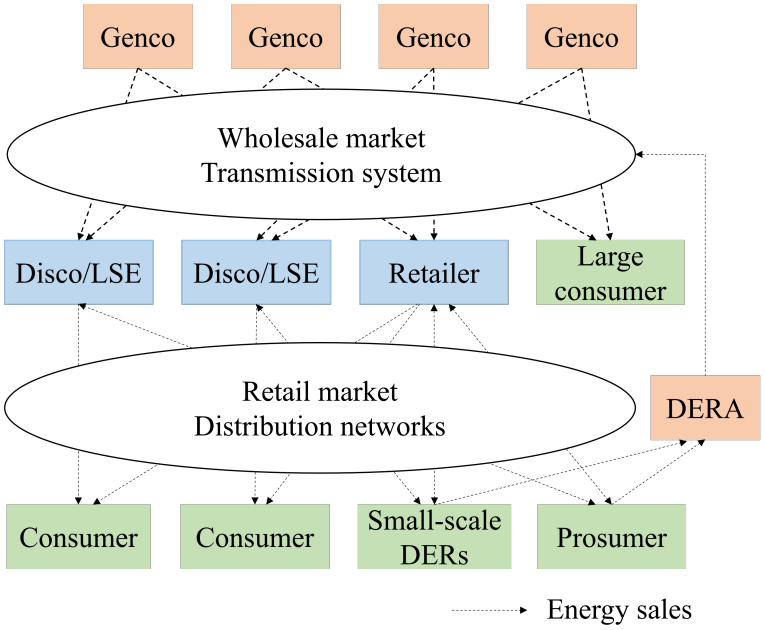


Figure 2.2: Wholesale and retail electricity market competition structures [118, 119]

tained [133]. The MCP is the dual variable associated with the demand-supply equality constraint. In perfect markets, these offers/bids are assumed to be their true benefits/costs respectively [132].

Whereas, in LMP markets, the energy price is determined at each node by solving a DC Optimal Power Flow (DC-OPF) problem. The DC-OPF seeks to maximize the social welfare subject to set of constraints. The LMP-based market model can easily capture the effect of line congestions by incorporating the transmission line flow constraints. It is to be noted that all the LMP-based markets in US are co-optimized energy-cum-operating reserve markets by design. The suppliers submit their offers both for energy market and for ancillary services. The market determines the LMPs for energy and operating reserve provision, dispatch schedules and ancillary services commitment of the cleared generation units at each node; subject to operational, technical and other relevant set of constraints [134–136].

Comparisons of UMP and LMP markets on some key attributes [136, 137]:

- UMP-based market requires separate technique to account for the effect of transmission congestions and losses. These separate heuristic methods result in approximate and non-optimal nodal prices and therefore, makes single-price merit order approach

economically less efficient. On the other hand, LMP-based market model implicitly takes into account the transmission congestions and losses while defining the model. And, therefore the output obtained is economically more efficient.

- UMP-based merit order approach is relatively very simple and computationally fast in comparison to the LMP-based market model.

2.3.4 Electricity Market Models

The basic mathematical models for LMP and UMP-based electricity markets are discussed next [75, 120, 133–136]:

LMP Market Model

Objective Function: The objective function to maximize social welfare is given as follows:

$$J = \sum_{q\epsilon Q} \sum_{h\epsilon N_{CB}} \sum_{i\epsilon I} (C^{D}_{i,h,q} P^{D}_{i,h,q}) - \sum_{q\epsilon Q} \sum_{j\epsilon J} \sum_{n\epsilon N_{GO}} (C^{G}_{n,j,q} P^{G}_{n,j,q}) - \sum_{q\epsilon Q} \sum_{j\epsilon J} (C^{SU}_{j,q} U_{j,q} + C^{DN}_{j,q} V_{j,q}) \tag{2.1}$$

The first term in (2.1) shows the gross surplus of consumers and the second term represents the generators' cost of supplying energy. The start-up and shut-down cost of generators which are given in the last term, shall be considered if LMP-based DAM is considered. Otherwise, typical an LMP model objective function comprises the first two terms only. The model is subject to the following set of constraints.

Demand-Supply Balance: This constraint ensures the balance between demand and supply at a bus, for each 'q' (market clearing interval); formulated using dc load flow equations wherein the line losses may be included using a linearized technique [120]. The dc load flow equations are used instead ac power flow equations in order to reduce the computational burden.

$$\sum_{j\epsilon J_i} P^{G}_{j,q} - P^{D}_{i,q} = \sum_{k\epsilon I} (0.5 P^{loss}_{i,k} + B_{i,k}(\delta_{i,q} - \delta_{k,q})) \qquad \forall q \,\epsilon\, Q \tag{2.2}$$

where,

$$P^{loss}_{i,k} = g_{i,k} \sum_{l\epsilon L} \alpha_{i,k}(l)(\delta_i(l) - \delta_k(l)) \qquad \forall i, k \,\epsilon\, I \tag{2.3}$$

and

$$\alpha_{i,k}(l) = (2l-1)\Delta\delta \qquad \forall i, k \,\epsilon\, I,\ \forall l \,\epsilon\, L \tag{2.4}$$

Market Clearing Constraints: Following constraints ensure that the market cleared quantities of consumers' purchase and generators' sell are within their respective maximum bid/offer quantities.

$$P^{G}_{n,j,q} \leq \bar{P}^{G}_{n,j,q}\, w_{n,j,q} \qquad \forall j \,\epsilon\, J,\ \forall q \,\epsilon\, Q,\ \forall n \,\epsilon\, N_{GO} \tag{2.5}$$

$$P^{D}_{i,h,q} \leq \bar{P}^{D}_{i,h,q}\, X_{i,h,q} \qquad \forall i \,\epsilon\, I,\ \forall q \,\epsilon\, Q,\ \forall h \,\epsilon\, N_{CB} \tag{2.6}$$

Other Constraints: These constraints include ensure transmission line limits and generalized UC constraints such as ramp-rate limits, minimum-up/down-time constraints, generation limits, reserve and coordination constraints. The ramping limits of generators denote the allowable MW increase/decrease across consecutive operating periods as per their technical characteristics. The minimum-up/down-time constraints of generators denote the minimum time for which a unit has to remain in the ON/OFF state before de-committing/committing respectively; formulated using a linearized technique presented in [120]. The generation limit constraints ensure that the power generation from a unit at any interval is within its maximum and minimum limits.

The Lagrangian multipliers associated with the demand-supply constraint are obtained from solving this DC-OPF problem and they denote the marginal cost of supplying an extra MWh at each bus, also referred to as LMPs. It can be noted that the above formulated mathematical model corresponds to the DAM model. Excluding the UC constraints and with some minor changes, this model can be formulated to represent an RTM model.

UMP Market Model

The mathematical model of the UMP-based market is similar to the LMP-based model with the major difference being in the demand-supply balance constraint. In the UMP model, a single price is determined for the whole system by considering the total generation equal to the total demand, irrespective of nodes or buses. The rest of the mathematical model (objective function and constraints) except the demand-supply balance for UMP model is almost same as the LMP model. The demand-supply balance constraint for the UMP model is as follows:

Demand-Supply Balance: This constraint ensures that the total cleared demand is equal to the total cleared generation at each 'q' (market clearing) intervals for the whole system.

$$\sum_{i \epsilon I} P^{D}_{i,q} = \sum_{j \epsilon J} P^{G}_{j,q} \qquad \forall q \, \epsilon \, Q \tag{2.7}$$

If the system loss function is known, then the above equality constraint can be modified to incorporate the losses by adding the loss term on left-hand side of (2.7).

2.4 Demand Response (DR)

DR can be briefly referred as "the act of shifting loads from one time period to another in response to an incentive" [114]. DR was founded as one of the effective solutions to demand side control in smart grids. DR programs can be classified into following categories depending upon price response, load response and customers' participation [63–67, 138]:

- Time-based: These programs notify the customers by sending a price signal or offering payments to alter their demand at a pre-determined period. Some of the main programs are:
  - Time-of-Use (TOU) Pricing: In this program, the electricity tariffs depend on the time of the day and season of the year. Typically, the low load period will have cheap electricity price, during mid-peak periods it will be moderate and the peak period will be high price. By participating in such programs, the customers adjust their demand by transferring their consumption from peak to mid-peak or low-demand periods.
  - Critical-Peak Pricing (CPP): It is a dynamic pricing scheme in which the electricity prices are determined by superimposing critical peak rates on TOU tariffs. Usually, the utilities implement such program for emergency cases or instances when high market prices are forecasted. For example, Ontario market practices such type of DR program, namely Industrial Conservation Initiative program, in which large consumers of electricity are charged Global Adjustment (GA) costs based on their usage during the five coinciding peaks in the system. Their overall GA charge decrease with the reduction of their demand during high demand days [139].

- Real-Time Pricing (RTP): is a dynamic pricing mechanism in which the retail price for electricity is updated depending upon the wholesale market clearing price, in close to real time.

- Incentive-based: These DR programs require customer to adjust their consumption and in return, are rewarded by incentives. Some examples of these programs are:

  - Direct Load Control (DLC): In this program, both the utilities and customers contractually agrees that the end-use appliance may be shut-down or operated in cycle control mode during critical periods. Generally, the customers are provided incentives in the form of electricity bill credits for providing such service. Typically, DLC notice is sent 15 min in advance. For example, Ontario market started such DR program, namely Peaksaver PLUS®, in which residential customers' loads such as air conditioner and water heater are remotely controlled by the Independent Electricity System Operator (IESO) to lower the customers' energy consumption during peak demand periods. After running this program for 10 years, it was discontinued in December, 2017 [140].
  - Interruptible/Curtailable Service (I/C): DR control mechanism in which utilities send interruption/curtailment request signals to the customers during critical peak hours, and interrupt power supply upon receipt of customers' responses.
  - Demand Side Biding/Buy Back: This program allows demand side resources to actively participate in the electricity markets, to obtain economic benefits by changing/reducing their consumption patterns. Once cleared in the auction, they are scheduled and dispatched in similar way as generators.
  - Emergency Demand Response Program (EDRP): This program requires customers to voluntarily alter their demand by shifting or reducing, in response to emergency request from utilities. The incentives are predetermined and there is no penalty on the customers for not adjusting their consumption [66].

2.5 Energy Storage Systems (ESSs)

Applications of ESS in the power system are gaining a lot of attention of utilities, policy makers, ISOs and researchers [141]. Various recent research focuses on examining the benefits of integrating ESSs in power systems [16]. Some of the key factors which are encouraging the operators to integrate ESSs into the power grid are high penetration of non-dispatchable and stochastic RES, decarbonization goals and finally, enhancing system

security and reliability [28]. Typically, ESS can be defined as a device/system which can store energy and later-on release it based on the requirements [30].

2.5.1 Energy Storage Systems (ESSs) Characteristics

Some of the fundamental terminologies associated with ESSs (in reference to their inclusion into the power grid), are briefly described below [142]:

- Power Capacity: maximum instantaneous power output that can be provided by ESS, and is generally expressed in kW or MW.
- Energy Storage Capacity: amount of electrical energy that can be stored by the ESS, and is usually expressed in kWh or MWh.
- Response Time: is the length of time required by the ESS to respond/react, and typically ranges from seconds to minutes.
- SOC/DOD: SOC represents the amount of energy remaining in the ESS, and usually expressed in percent or per-unit (p.u.). The DOD represents the amount of energy required to fully recharge the ESS or it can be defined as the ESS capacity discharged as a fraction of its maximum capacity, and typically expressed in percent or per-unit (p.u.). Therefore, DOD and SOC can be mathematically equated as SOC = 1 - DOD.
- Ramp Rate: is the rate of change of ESS output power, and generally represented in kW/s.
- Round-trip Efficiency: denotes the quantity of energy that can be retrieved as a fraction of total energy used to charge and discharge the ESS.
- Cycle life: is the number of charge-discharge cycles that ESS can undergo before it reaches a stage when it no longer meets the specified requirements.
- C-Rate: represents the energy depletion rate of the ESS. For example, C-Rate = 1 means the energy capacity of ESS is depleted in 1 hour. Further, C-Rate = 2 denotes that the depletion rate has doubled *i.e.*, the ESS depletes in 30 minutes, and so forth.
- Derating Factor: is used to take into account the effect of degradation and/or State-of-Health (SOH) of the ESS. It is a multiplier which is applied to the ESS rated capacity to obtain the derated capacity.

2.5.2 Operational Aspects and Model of BESS

A typical BESS will comprise battery, Battery Management System (BMS), power converter and controller [143]. Each component has its own specific role in the BESS. The battery pack constitutes many cells connected in various configurations based on the type of requirements. The controller acts as the brain of the system and includes the operation and control logic architecture. The other important component is power converter which functions as an inverter/rectifier depending upon the BESS discharging/charging operation, respectively. Finally, monitoring and managing of the BESS is performed by the BMS which monitors various characteristics such as SOC, temperature, SOH, etc. The BESS operates in following three modes:

- Charging Mode: In this mode, the BESS acts as a load and consumes electrical energy. The SOC increases, depending on the amount of energy consumed.
- Discharging Mode: In this mode, the BESS serves as a generator by supplying the energy to the grid. Based on the amount of energy supplied, the SOC decreases.
- Idle Mode: In this mode, the BESS is neither charging nor discharging, but remains connected to the grid. Thus, it is able to provide SR services.

Apart from the SOC, there are some key attributes that need to be considered when defining the operational model for BESS. These include discharge rate, derating factor and cycle life. Below is the basic mathematical model of Li-Ion BESS from an operational point of view [35, 144]:

The objective function is generally to maximize the profit of BESS owner from its participation in the markets, given as follows:

$$J = \sum_{t \epsilon Q} \sum_{e \epsilon E} \left[(P_{e,t}^{Dch} - P_{e,t}^{ch}) \pi_t^E + P_{e,t}^{BESR} \pi_t^{SR} \right] \tag{2.8}$$

OR

$$J = \sum_{t \epsilon Q} \sum_{e \epsilon E} (C_{e,t}^{Dch} E_{e,t}^{Dch} - C_{e,t}^{ch} E_{e,t}^{ch} + C_{e,t}^{BESR} E_{e,t}^{SRC}) \tag{2.9}$$

Equation (2.8) illustrates the participation of BESS as a price-taker while the objective function in (2.9) represents the BESS participation by submitting bids/offers in energy

and SR markets. The above-mentioned objective functions are subject to the following operational constraints:

$$SOC_{e,t+1} - SOC_{e,t} = (P^{ch}_{e,t}\eta^{ch}_{e} - P^{Dch}_{e,t}/\eta^{Dch}_{e})\Delta t \qquad \forall e \,\epsilon\, E,\ \forall t\ > 0 \tag{2.10}$$

Equation (2.10) represents the SOC of BESS at each interval 't' based on the state at previous interval and the operation occurred between the intervals. In order to avoid simultaneous charging and discharging of a BESS, the following constraint is used.

$$Z1_{e,t} + Z2_{e,t} \leq 1 \qquad \forall e \,\epsilon\, E,\ \forall t \,\epsilon\, Q \tag{2.11}$$

The following set of equations defines the boundary limits of BESS charging power, discharging power and SOC respectively:

$$P^{ch}_{e,t} \leq \overline{P}_{ch_e} Z1_{e,t} \qquad \forall e \,\epsilon\, E,\ \forall t \,\epsilon\, Q \tag{2.12}$$

$$P^{Dch}_{e,t} \leq \overline{P}_{Dch_e} Z2_{e,t} \qquad \forall e \,\epsilon\, E,\ \forall t \,\epsilon\, Q \tag{2.13}$$

$$\underline{SOC_e} \leq SOC_{e,t} \leq \overline{SOC_e} \qquad \forall e \,\epsilon\, E,\ \forall t \,\epsilon\, Q \tag{2.14}$$

The discharge rate of the BESS in terms of SOC and time is expressed as follows:

$$DCR_{e,t} = (SOC_{e,t-1} - SOC_{e,t})/\Delta t \qquad \forall e \,\epsilon\, E,\ \forall t \,\epsilon\, Q \tag{2.15}$$

The effect of the battery's degradation based on discharge rate and DOD on the BESS operational model is considered through degradation cost function as proposed in [35], which is:

$$C1_t = aSOC_t + bSOC_{t-1} + cDCR_t + d \qquad \forall t \,\epsilon\, Q \tag{2.16}$$

2.5.3 Operational Aspects and Model of HSS

Hydrogen cycle can be broadly categorized into three stages: hydrogen production, hydrogen storage and lastly, stored hydrogen utilization [146]; which are elaborated as follows:

Hydrogen Production: There are three predominant techniques which are currently practiced for hydrogen production namely, coal gasification, Steam Methane Reformation

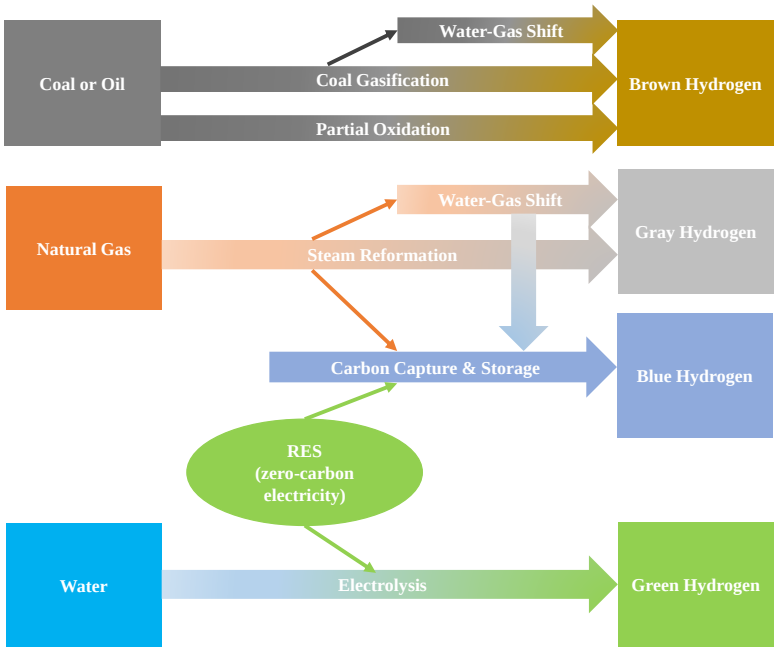


Figure 2.3: Predominant pathways for hydrogen production [145]

(SMR) and electrolysis of water. Though hydrogen is a colourless gas, hydrogen is labelled in different "colors" (as illustrated in Fig. 2.3) based on the production technique, the energy sources used and the climate neutrality of the process [145, 147].

Below is the brief overview of hydrogen production techniques and corresponding color label:

- Coal Gasification: It works by heating the coal in the presence of steam and oxygen to produce carbon monoxide and hydrogen, given as follows:

$$3C + O_2 + H_2O \rightarrow H_2 + 3CO \tag{2.17}$$

  Reaction (2.17) is generally followed by the water-gas shift reaction, to transform water into gaseous hydrogen and hence, increase the hydrogen production.

$$CO + H_2O \rightarrow H_2 + CO_2 \tag{2.18}$$

  It can be noticed from the above reactions that along with hydrogen, carbon dioxide is other major output of the gasification process and it utilizes coal as input, therefore the hydrogen produced is labelled as brown.

- SMR: This is the most used technique for hydrogen production, and involves heating of the methane (from natural gas) in the presence of a catalyst at temperature around 700-1100°C.

$$CH_4 + H_2O \rightarrow 3H_2 + CO \tag{2.19}$$

  This step is followed by water-gas shift reaction to maximize the hydrogen production. Since the CO_2 available at the end of water-gas shift process is pure (100%) and produced along with hydrogen, it is ideal to store the CO_2. The hydrogen produced through SMR technique is referred to as gray hydrogen and if the CO_2 is captured and stored to limit the emissions, then it is labelled as blue hydrogen.

- Electrolysis: This method utilizes electrical energy to split water into its constituent chemical compounds, namely oxygen and hydrogen.

$$2H_2O \rightarrow 2H_2 + O_2 \tag{2.20}$$

  If RES are deployed to supply electrical energy for the electrolysis, then the hydrogen produced is labelled as *green* hydrogen due to the fact that the whole process would be NZE. Many research works are carried out worldwide to make the production of green hydrogen more efficient and economical.

Hydrogen Storage: There are numerous ways of storing hydrogen depending on the duration of storage, volume of stored amount, geographic availability, speed of discharge, and type of application. Hydrogen has a good energy density by mass, however it possesses very low energy density by volume. Commonly, hydrogen is stored as a gas or liquid in tanks for small-scale immobile and mobile applications, while geological storage such as salt caverns, seems to be the best option for long-term and large-scale storage. Moreover, liquid hydrogen under ambient conditions boils at -253°C, hence it requires to be stored cryogenically. Additionally, hydrogen can also be stored within solids (by absorption) or on the surfaces of solids (by adsorption) [7, 147].

Stored Hydrogen Utilization: There are many sectors and emerging fields which require hydrogen. Some of the key consumption are in refinery, chemical industries, iron & steel production, high-temperature heat usage, transport, buildings and power sector. Due to brevity, the ways hydrogen is used in these applications in today's scenario and its future prospects are not discussed here, however in [147] the authors have covered these aspects in detail. Given the research scope of this thesis, the utilization of hydrogen to produce electrical energy is explained herein. Presently, the production of electricity from hydrogen-rich gases is more efficient than that using 100% hydrogen, because the gas turbines of today

are not designed to work efficiently on pure hydrogen. However, it is expected that with advancements in gas turbine technology, it would be able to produce electricity efficiently with pure hydrogen in the near future. Moreover, fuel cells are an attractive option for electricity production from hydrogen with no direct emissions, apart from its possibility of utilization in many other sectors such as transportation, microgrid applications, etc. A fuel cell is defined as *"an electrochemical device that converts chemical energy of reactants (both fuel and oxidant) directly into electrical energy"* [148]. The fuel cell is typically composed of three active elements: a fuel electrode (anode), an oxidant electrode (cathode) and an electrolyte between them. The following reactions depicts the working of a fuel cell:

$$\text{Anode half-cell reaction:} \quad H_2 \rightarrow 2H^+ + 2e^- \tag{2.21}$$

$$\text{Cathode half-cell reaction:} \quad \frac{1}{2}O_2 + 2H^+ + 2e^- \rightarrow H_2O \tag{2.22}$$

$$\text{Overall cell reaction:} \quad H_2 + \frac{1}{2}O_2 \rightarrow H_2O + E + WasteHeat \tag{2.23}$$

The term E in (2.23) refers to useful electrical energy output from the fuel cell. It is

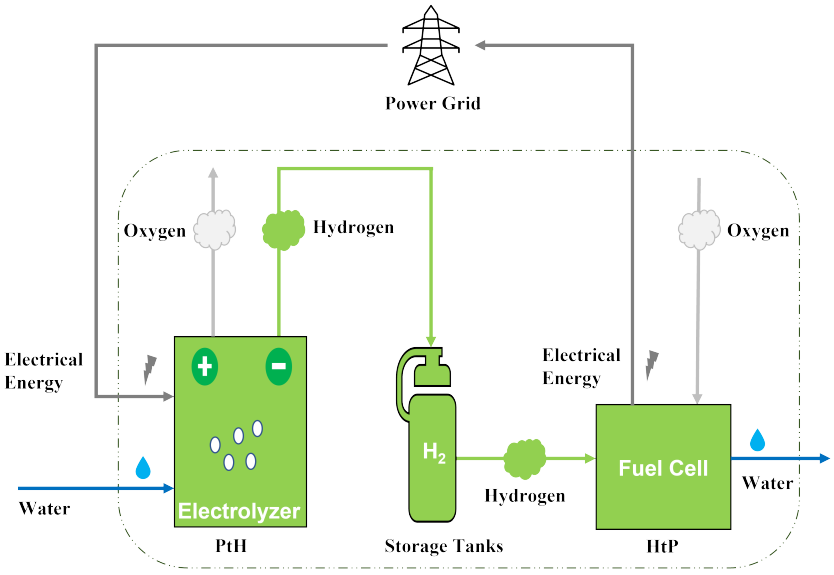


Figure 2.4: Typical layout of Power-to-Hydrogen-to-Power (PtH-HtP) system [149, 150]

a promising technology alternative for load balancing, flexible generation and back-up & off-grid power supply. Fuel cells can be classified in different ways depending upon various criteria [148]. Relevant to this research focusing on the stationary power applications,

various technologies of fuel cells generally used are: polymer electrolyte membrane fuel cells (PEMFCs), phosphoric acid fuel cells (PAFCs), molten carbonate fuel cells (MCFCs) and solid oxide fuel cells (SOFCs) [147].

Fig. 2.4 illustrates the typical layout of Power-to-Hydrogen-to-Power (PtH-HtP) system and its components, which comprises an electrolyzer, storage for hydrogen gas and fuel cell [149–151]. Similar to other ESSs, this system also operates in three modes, which are as follows:

- Charging Mode: In this mode, the PtH-HtP facility utilizes electrical energy from the grid to produce hydrogen via electrolyzer (Power-to-Hydrogen (PtH) process) and store it. In charging mode, the PtH-HtP facility needs to pay for the electricity drawn from the grid.
- Discharging Mode: In this mode, the stored hydrogen is extracted and used to produce the electrical energy through fuel cell (Hydrogen-to-Power (HtP) process). In this mode, the PtH-HtP facility is paid for the energy supplied to the grid.
- Idle: In this mode, the PtH-HtP facility neither charges nor discharges.

Below is a brief operational model of the HSS/PtH-HtP system (as illustrated in Fig. 2.4), which consists of an electrolyzer, storage tank and fuel cell as its components [152]. The objective function is to maximize the profit of the HSS owner from its participation in the markets, given as follows:

$$J = \sum_{t \epsilon Q} (P_t^{hyd,FC} - P_t^{hyd,EL}) \pi_t^E \tag{2.24}$$

Equation (2.24) represents the participation of the HSS as a price-taker in an electricity market, subject to the following operational constraints:

$$N_t^{hyd,EL} = \frac{\eta^{hyd,EL} P_t^{hyd,EL}}{LHV^{hyd}} \qquad \forall t \, \epsilon \, Q \tag{2.25}$$

Equation (2.25) depicts the number of hydrogen moles generated in terms of the power drawn by the electrolyzer.

$$N_t^{hyd,EL} \leq N_{max}^{hyd,EL} H_t^{EL} \qquad \forall t \, \epsilon \, Q \tag{2.26}$$

The maximum number of hydrogen moles that can be produced by the electrolyzer are limited by (2.26).

$$P_{min}^{hyd,EL} H_t^{EL} \leq P_t^{hyd,EL} \leq P_{max}^{hyd,EL} H_t^{EL} \qquad \forall t \, \epsilon \, Q \tag{2.27}$$

Equation (2.27) represents the maximum and minimum power consumption limits of the PtH component of the HSS system *i.e.* the electrolyzer.

$$N_t^{hyd,FC} = \frac{P_t^{hyd,FC}}{\eta^{hyd,FC} LHV^{hyd}} \qquad \forall t \, \epsilon \, Q \tag{2.28}$$

Equation (2.28) represents the number of hydrogen moles utilized for power generation by the fuel cell.

$$N_t^{hyd,FC} \leq N_{max}^{hyd,FC} H_t^{FC} \qquad \forall t \, \epsilon \, Q \tag{2.29}$$

The maximum number of hydrogen moles that can be utilized by the fuel cell are limited by (2.29).

$$P_{min}^{hyd,FC} H_t^{FC} \leq P_t^{hyd,FC} \leq P_{max}^{hyd,FC} H_t^{FC} \qquad \forall t \, \epsilon \, Q \tag{2.30}$$

Equation (2.30) represents the maximum and minimum limit on power generation by the HtP component of HSS system *i.e.* fuel cell. In order to avoid the simultaneous charging and discharging of an HSS, the following constraint is applied:

$$H_t^{EL} + H_t^{FC} \leq 1 \qquad \forall t \, \epsilon \, Q \tag{2.31}$$

It is to be noted that constraint (2.31) is redundant for the system under consideration in this thesis. This is because in the electricity market context, the electrolyzer, storage tank and fuel cell units are owned and operated by a single market participant and they are located at the same bus. Therefore, it is not feasible to clear bids/offers for the same participant at an hour. The inclusion of this constraint ensures a generic and futuristic mathematical model for a GHS which can implement a reversible electrolyzer instead of separate electrolyzer and fuel cell units; in which a single device performs both charging and discharging operations. Furthermore, this constraint is necessary as hydrogen produced by the electrolyzer unit need to be adjusted to a specific temperature for storage and then make stored hydrogen suitable for feeding to the fuel cell unit. It reduces the operational complexity and helps manage the GHS operations safely.

The pressure in the hydrogen storage tank at any time 't' as a function of the pressure at previous interval 't-1', the number of hydrogen moles generated by the electrolyzer and that utilized by the fuel cell is represented by following equation:

$$Pr_t^{hyd} = Pr_{t-1}^{hyd} + \frac{\Re T^{hyd}}{V^{hyd}}(N_t^{hyd,EL} - N_t^{hyd,FC}) \qquad \forall t \, \epsilon \, Q \tag{2.32}$$

The following constraints define the maximum and minimum pressure limits of the hydrogen storage tanks:

$$Pr_{min}^{hyd} \leq Pr_t^{hyd} \leq Pr_{max}^{hyd} \qquad \forall t \, \epsilon \, Q \tag{2.33}$$

The hydrogen-based system can be modelled as an energy resource or a storage resource depending upon components considered in the system and type of system being accounted for. Since, the work in this thesis focuses on accelerating NZE grid and does not explore sector-coupling environment, all the corresponding works presented herein have modelled hydrogen-based resource as energy storage within the electric power sector.

2.6 ISO-DSO Coordination

With the release of FERC Order 2222, the DERs are now allowed to participate in energy, ancillary service and capacity markets, predominantly through aggregators in order to adhere to the requirement of minimum size criteria [48]. The DERA, which are typically consumers or third parties, play the role of aggregating energy generation and/or storage resources to provide energy or grid services [114]. Some key attributes for a resource to be termed a DER are their size, technology and point-of-connection. The minimum size criteria defined by FERC Order 2222 specified a minimum of 100 kW capacity for a DER or DERA to participate in US energy markets. IEEE Standard 1547 [153] outlined the technology requirements criteria for being classified as DER, wherein some key attributes include reactive power support, bulk power support, ride-through requirements, power quality, interoperability and communication. With regard to the point-of-connection criteria, typically, a DER may be connected in two configurations namely, In-Front-of-Meter (IFM) or BTM. Generally, IFM-DERs are larger in capacity and can directly participate in the wholesale energy markets. On the other hand, BTM-DERs are generally smaller in capacity and not eligible to participate directly in the wholesale markets [31, 32].

A transmission system can be characterized as a meshed network with energy flows at high voltage levels, connecting to bulk power plants, large consumers and lower voltage

distribution systems. While the distribution systems are typically radial circuits at low-voltage levels, connecting distributed generation sources and end-users [118, 119]. In the modern grid, the power flows are no longer unidirectional and can be bidirectional from transmission to distribution or vice-versa, and this requires the coordination between the two levels for effective system operation [38, 40–42]. For smooth operation of the coordination framework, the ISO and DSOs need to define their roles, responsibilities, policies, information exchange (technical, physical and economic), communication mode, services offered and the market structure [48]. In the literature, researchers have proposed various coordination schemes between transmission and distribution levels to facilitate DERs participation in different markets [38,41,48,95,96,104,109,154,155]. These can be summarized broadly as follows:

- *Centralized ISO*: In such a scheme, the ISO settles the wholesale market considering distribution systems and DERs location at various nodes in the distribution network. In this arrangement, the discos / LSEs / LDCs oversee the distribution network connection to end-users and maintenance. The advantages in this model is that even small-scale DERs can directly participate in the wholesale market and the optimal dispatches are obtained from the centralized optimization model. However, the computational burden is very high and requires significant amount of information to be shared with the ISO; which makes this model highly unlikely to be adopted.

- *Approximate centralized ISO*: The market settlement by the ISO in this scheme, considers the power injections from DERs located in the distribution system, to be at the wholesale coupling bus, while neglecting the distribution network and associated constraints. This scheme also requires information on all DERs and the discos / LSEs / LDCs have to perform network studies after the market settlement to ensure congestion management, meeting voltage and other constraints, since the ISO dispatches the DERs at the coupling buses without knowing their impact on the distribution system.

- *Aggregator-based ISO*: This scheme works on the principles articulated in FERC Order 2222 wherein the aggregator submits bids/offers in the wholesale market by aggregating multiple DERs bids/offers while fulfilling the minimum size criterion of 100 kW. The ISO settles the wholesale market considering the transmission system only and the multiple aggregated or "virtual" resources at the coupling buses. This scheme is computationally faster compared to the earlier two and protects DERs' privacy; however, the clearance of DERs (especially small-scale/BTM-type DERs) depend on the aggregated marginal bid/offer which camouflages their individual bids/offers

within the aggregator's curve. The true bids/offers of the DERs are not exposed to the wholesale market and hence their clearance is limited thus making their participation inequitable. The role of the discos / LSEs / LDCs is limited to ensuring the reliability and operational aspects of the distribution network based on the market outcomes from the ISO.

- *Hybrid ISO-DSO*: In this scheme, the discos / LSEs / LDCs undertake new responsibilities to enact as a distribution level system operator, referred to as *DSO*. The DSO performs the role which was executed by the DERA in the Aggregator-based ISO scheme, *i.e.* aggregating and coordinating all the DERs and end-users within its distribution network and submits aggregated bid/offer to the ISO at the coupling bus for participating in the wholesale market. The DSO coordinates among DERs based on ISO dispatch signals and also carries out distribution network management. This scheme is considered to be computationally at par with the Aggregator-based ISO Model and faster than the earlier two while also ensuring DERs privacy. But it also possesses similar challenges as in the Aggregator-based ISO Model with the aggregation approach. The DSOs in such schemes are termed as *minimal DSOs* based on their role.

- *Decentralized/Distributed ISO-DSO*: This scheme further enhances the role and responsibilities of the DSO in which the DSO may operate a retail market at the distribution level while coordinating with the ISO in the wholesale market. There are two broad approaches reported in the literature under this scheme: (a) top-down approach (also referred as price-taker DSO model) and (b) bottom-up approach (also referred as price-maker DSO model); both these approaches follow a sequential market coordination and settlement. In the top-down approach, the DSO receives the wholesale price of the coupling bus as *ex-ante* input from the ISO for settling its retail market at the distribution level. It optimizes the dispatch schedules of DERs while taking into account the retail market and its operational constraints. On the other hand, in the bottom-up approach, the DSO executes the retail market first and thereafter submits bids/offers at the coupling bus to the wholesale market.

  In this Decentralized/Distributed ISO-DSO scheme, each market (wholesale and retail) are settled, operated and managed by their respective system operator (ISO and DSO). Such models are computationally faster, require minimal exchange of information between the ISO and DSOs, ensure own network management, are scalable and anticipated to be adopted in the future electricity markets. The DSOs in such a scheme are also termed as *total DSOs* in some reported works. However, this scheme still does not fully overcome the issue of camouflaging of DERs bids/offers in

aggregation method in the bottom-up approach while the top-down approach does not provide an equitable and competitive platform for DERs participation and hence unable to utilize the true potential of DERs.

2.7 Summary

In this chapter, the key background topics relevant to the research performed and presented in this thesis, were covered. A general overview of electricity markets was presented, with a discussion on the types of markets based on levels (wholesale and retail), time-horizon (DAM and RTM) and pricing scheme (LMP and UMP). Thereafter, the mathematical models were presented for LMP and UMP markets. Then, different types of DR programs were discussed. Further, an overview of ESTs was presented, with an elaborate description of their associated characteristics. The basic operational aspects and mathematical models for BESS and HSS were presented. Finally, the chapter discussed the various coordination schemes between the ISO and DSOs along with their respective merits and challenges.

Chapter 3

Integrating Green Hydrogen Systems and Emission Control Strategies in UMP-based Day-ahead Electricity Markets[1]

3.1 Nomenclature

Sets & Indices

i	Buses, $i \in I$.
s	Green hydrogen system units, $s \in GHS$.
j	Generators (gencos), $j \in J$.
q	Time (hour), $q \in Q$.

[1]Parts of this chapter have been published in:

- A. Goyal and K. Bhattacharya, "Integrating Green Hydrogen Systems and Emission Control Strategies in Electricity Markets: Case of Alberta and Ontario," *CIGRE Science & Engineering Journal*, June 2024.
- A. Goyal and K. Bhattacharya, "Integrating Green Hydrogen Systems in Day-Ahead Electricity Market Auctions," *2023 CIGRE Canada Conference & Exhibition*, Vancouver, Canada, September 2023.

h	Blocks of consumer bids, $h \in N_{CB}$.
g	Blocks of gencos offers, $g \in N_{GO}$.
wg	Wind generation facilities, $wg \in WG$.
pv	Solar (PV) facilities, $pv \in PV$.
J_{hydro}	Hydro generators.

Parameters

C^{Con}	Consumers bid price in DAM, \$/MWh.
C^{Gen}	Gencos energy offer price in DAM, \$/MWh.
$C^{Gen_{SU/DN}}$	Gencos start-up/shut-down cost, \$.
$C^{RES_{wg}}$	Wind energy offer price in DAM, \$/MWh.
$C^{RES_{pv}}$	Solar (PV) energy offer price in DAM, \$/MWh.
$C^{GHS_{ch/Dch}}$	GHS charging/discharging bid/offer price in DAM, \$/MWh.
C^{Emm}	Carbon pricing in DAM, \$/tonnes.
EF^{Gen}	Gencos emission factor, tonnes/MWh.
$\overline{N}^{GHS_{EL}}$	Maximum number of hydrogen moles produced by the electrolyzer, mol.
α^{Cap}	Emission cap as fraction of emission of BAU, %.
$\eta^{GHS_{ch/Dch}}$	Efficiency of GHS charging/discharging operation, %.
LHV^{GHS}	Minimum thermal energy content of hydrogen, MW/mol.
$\overline{P}^{GHS_{EL}}$	Maximum power of the electrolyzer, MW.
$\underline{P}^{GHS_{EL}}$	Minimum power of the electrolyzer, MW.
$\overline{Pr}^{GHS_{ST}}$	Maximum pressure of the GHS storage tank, Pa.
$\underline{Pr}^{GHS_{ST}}$	Minimum pressure of the GHS storage tank, Pa.
$\overline{P}^{GHS_{FC}}$	Maximum power generated by the fuel cell, MW.
$\underline{P}^{GHS_{FC}}$	Minimum power generated by the fuel cell, MW.
$\overline{N}^{GHS_{FC}}$	Maximum number of hydrogen moles consumed by the fuel cell, mol.

$T^{GHS_{ST}}$	Average temperature of the GHS storage tank, K.
$V^{GHS_{ST}}$	Volume of the GHS storage tank, m^3.
$\Re$	Constant of gases, $JK^{-1}mol^{-1}$.
Emm^{BAU}	Total system emissions in the BAU, tonnes.

Variables

P^{Con}	Demand cleared in DAM, MW.
P^{Gen}	Gencos offer cleared for energy in DAM, MW.
$P^{RES_{wg}}$	Wind generation cleared in DAM, MW.
$P^{RES_{pv}}$	Solar (PV) generation cleared in DAM, MW.
$P^{GHS_{EL}}$	GHS charging power (electrolyzer) in DAM, MW.
$P^{GHS_{FC}}$	GHS discharging power (fuel cell) in DAM, MW.
U, V	1, if gencos start/shut-down, 0 otherwise.
$H^{GHS_{EL/FC}}$	1, if GHS charging/discharging, 0 otherwise.
$N^{GHS_{EL}}$	Number of hydrogen moles produced by electrolyzer (GHS charging), mol.
$Pr^{GHS_{ST}}$	Pressure of the GHS storage tank, Pa.
$N^{GHS_{FC}}$	Number of hydrogen moles consumed by fuel cell (GHS discharging), mol.

3.2 Introduction

This chapter presents a framework and appropriate market design to integrate GHSs in the electricity markets, to explore their role in achieving a net-zero CO_2 emissions grid [2]. Furthermore, a comprehensive sensitivity analyses is carried out to examine the model performance under RES uncertainties and to investigate the effect of inclusion of GHS in the DAM with different emission control strategies, such as emission cap and carbon pricing, and furthermore examine the effect of varying GHS operational characteristics *i.e.* storage tanks' initial moles content. The work presented here is carried out with the assumption that only GHS, and no other competing ESTs such as BESS, compressed

air energy storage, thermal storage, *etc.* are considered in the electricity markets under study. This is because presently the cost metrics of other ESTs are comparatively lower than GHS; however, each ESS has its own merits and challenges. Therefore, in order to have a global solution we need to explore role of different ESS and also, it is anticipated that hydrogen will be playing a pivotal role in achieving NZE ecosystem and its cost will decline with advancement in technology and mass production. The two real systems, Alberta and Ontario provinces of Canada, are considered to examine the benefits of the proposed framework and market model wherein the current supply mix of technologies are included.

3.3 GHS Integrated UMP-based DAM Framework and Auction Model

3.3.1 Proposed GHS Integrated DAM Framework

In this work, a novel framework is proposed to enable GHS participation in the DAM as a market participant. The GHS considered, comprises of three major components: electrolyzers, storage tanks and fuel cells. A grid-scale, independently owned GHS participates in the DAM auction by submitting bids (in price-quantity pairs) to buy energy and offers (in price-quantity pairs) to sell energy to the ISO. Other market participants also submit their bids/offers to the ISO based on their functionality such as consumers submit buy bids for energy, gencos submit sell offers for energy, RES submit sell offers for energy, *etc.* Once the bids and/or offers are received from various market participants, the ISO settles the DAM to release the market settlement outcomes. In this work, the market settlement is carried out by considering a double-auction UMP-based DAM, which is formulated as an MIP optimization model. The outputs of the model comprises UC decisions, dispatch schedules of generators and loads, GHSs charging and discharging operations, MCPs and total emissions.

3.3.2 GHS Integrated UMP-based DAM Auction Model

Objective Function

To maximize the social welfare, given as follows:

$$J = \underbrace{\sum_{q\epsilon Q}\sum_{i\epsilon I}\sum_{h\epsilon N_{CB}}(C^{Con}_{h,i,q}P^{Con}_{h,i,q})}_{\text{(Consumers' Gross Surplus)}} \underbrace{-\sum_{q\epsilon Q}\sum_{wg\epsilon WG}(C^{RES_{wg}}_{wg,q}P^{RES_{wg}}_{wg,q}) - \sum_{q\epsilon Q}\sum_{pv\epsilon PV}(C^{RES_{pv}}_{pv,q}P^{RES_{pv}}_{pv,q})}_{\text{(Energy Supply Costs from RES (Wind and Solar))}}$$
$$\underbrace{-\sum_{q\epsilon Q}\sum_{j\epsilon J}\sum_{g\epsilon N_{GO}}(C^{Gen}_{g,j,q}P^{Gen}_{g,j,q})}_{\text{(Gencos' Energy Supply Costs)}} \underbrace{-\sum_{q\epsilon Q}\sum_{j\epsilon J}(C^{Gen_{SU}}_{j,q}U_{j,q} + C^{Gen_{DN}}_{j,q}V_{j,q})}_{\text{(Gencos' Start-up and Shut-down Costs)}} \underbrace{+\sum_{q\epsilon Q}\sum_{s\epsilon GHS}(C^{GHS_{ch}}_{s,q}P^{GHS_{EL}}_{s,q})}_{\text{(GHSs' Charging Surplus)}}$$
$$\underbrace{-\sum_{q\epsilon Q}\sum_{s\epsilon GHS}(C^{GHS_{Dch}}_{s,q}P^{GHS_{FC}}_{s,q})}_{\text{(GHSs' Discharging Costs)}} \underbrace{-\sum_{q\epsilon Q}\sum_{j\epsilon J}\sum_{g\epsilon N_{GO}}(C^{Emm}_{g,j,q}EF^{Gen}_{g,j,q}P^{Gen}_{g,j,q})}_{\text{(a: Carbon Pricing)}} \quad (3.1)$$

The first term in (3.1) represents the consumers' gross surplus. The second and third terms denote the total cost of energy supply from RES (wind and solar). The fourth term denotes the operational cost of gencos for energy supply. The start-up and shut-down cost of gencos are given by the fifth term. The sixth term represents the charging cost of GHSs while the seventh term denotes the discharging cost of GHSs for energy supply. Lastly, the eighth term represents the carbon pricing pertaining to total carbon emissions. Equation (3.1), excluding term (a), represents the objective function of the DAM without considering carbon emissions pricing.

It is interesting to note that in (3.1), the second and third terms denote the total cost of energy supply from RES (wind and solar) which are non-dispatchable and zero/low marginal cost resources. Due to these reasons, the RES presently do not submit offers in electricity markets worldwide. However, in order to formulate a market model to reflect emerging electricity markets with energy transition and high proliferation of RES, the owners of such resources, with the help of suitable storage capacity, are envisaged to be competing in the electricity markets by submitting offers. The objective functions throughout the thesis take into account this vision of emerging electricity markets.

Along with other ongoing efforts to achieve decarbonization in the energy sector, one of the attractive mechanisms is to implement emission trading. Carbon pricing is one of such emission trading scheme wherein the system is penalized based on its emissions, typically quantified in terms of CO_2 or CO_{2eq} emissions contributed. Such schemes are needed to

meet climate change challenges and accelerate the process of decarbonization. Carbon pricing assists in monetizing the environmental factors associated with different types of resources and mostly results in higher market prices. To this effect, low/zero emission resources are benefited by their increased chances of clearance despite being costlier, while net revenue and total dispatch of emission-intensive resources reduces. In this work, carbon pricing is formulated by considering an emission factor (expressed in tonnes/MWh) of each participating resource which varies based on resource-type, cost associated with emissions ($/tonnes) and hourly generation being cleared from the respective resource in the DAM. The objective function is subjected to the following set of constraints.

Demand-Supply Balance

This constraint ensures the balance between demand and supply for the system at each hour.

$$\sum_{j\epsilon J} P_{j,q}^{Gen} + \sum_{wg\epsilon WG} P_{wg,q}^{RES_{wg}} + \sum_{pv\epsilon PV} P_{pv,q}^{RES_{pv}} + \sum_{s\epsilon GHS} P_{s,q}^{GHS_{FC}} - \sum_{s\epsilon GHS} P_{s,q}^{GHS_{EL}} - \sum_{i\epsilon I} P_{i,q}^{Con} = 0 \quad \forall q \,\epsilon\, Q \quad (3.2)$$

Emission Cap Constraints

This constraint ensures that the total emissions of a system are limited to a fraction of the emissions in the case without any emission cap.

$$\sum_{q\epsilon Q} \sum_{j\epsilon J} (EF_{j,q}^{Gen} P_{j,q}^{Gen}) \leq \alpha^{Cap} Emm^{BAU} \quad (3.3)$$

GHS Constraints: Energy Arbitrage, Physical and Operational

Electrolyzer Constraints:

The number of hydrogen moles generated in terms of the power drawn by the electrolyzer are given by,

$$N_{s,q}^{GHS_{EL}} = \frac{\eta_s^{GHS_{ch}} P_{s,q}^{GHS_{EL}}}{LHV^{GHS}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \quad (3.4)$$

Maximum number of hydrogen moles that can be produced by the electrolyzer are limited as follows:

$$N_{s,q}^{GHS_{EL}} \leq \overline{N}_{s}^{GHS_{EL}} H_{s,q}^{GHS_{EL}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.5}$$

While the maximum and minimum power consumption limits of the PtH component of the GHS *i.e.* electrolyzer, are given by,

$$\underline{P}_{s}^{GHS_{EL}} H_{s,q}^{GHS_{EL}} \leq P_{s,q}^{GHS_{EL}} \leq \overline{P}_{s}^{GHS_{EL}} H_{s,q}^{GHS_{EL}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.6}$$

Storage Tank Constraints:

Based on the Gas Law [156], the pressure in the hydrogen storage tank at any time q can be expressed as a function of the pressure at the previous interval *q-1*, the number of hydrogen moles generated by the electrolyzer and utilized by the fuel cell, given by the following equations:

$$Pr_{s,q}^{GHS_{ST}} = Pr_{s,q-1}^{GHS_{ST}} + \Delta Pr_{s,q}^{GHS_{ST}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.7}$$

where

$$\Delta Pr_{s,q}^{GHS_{ST}} = \frac{\Re T_{s}^{GHS_{ST}}}{V_{s}^{GHS_{ST}}} (\Delta N_{s,q}^{GHS}) \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.8}$$

and

$$\Delta N_{s,q}^{GHS} = (N_{s,q}^{GHS_{EL}} - N_{s,q}^{GHS_{FC}}) \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.9}$$

Following constraints define the maximum and minimum pressure limits of the hydrogen storage tanks:

$$\underline{Pr}_{s}^{GHS_{ST}} \leq Pr_{s,q}^{GHS_{ST}} \leq \overline{Pr}_{s}^{GHS_{ST}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.10}$$

Fuel Cell Constraints:

The number of hydrogen moles utilized for power generation by the fuel cell is given by,

$$N_{s,q}^{GHS_{FC}} = \frac{P_{s,q}^{GHS_{FC}}}{\eta_{s}^{GHS_{Dch}} LHV^{GHS}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.11}$$

Maximum number of hydrogen moles that can be utilized by the fuel cell are limited by the following:

$$N_{s,q}^{GHS_{FC}} \leq \overline{N}_{s}^{GHS_{FC}} H_{s,q}^{GHS_{FC}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.12}$$

The maximum and minimum limit on power generation by the HtP component of the GHS *i.e.* fuel cell, are given as follows:

$$\underline{P}_{s}^{GHS_{FC}} H_{s,q}^{GHS_{FC}} \leq P_{s,q}^{GHS_{FC}} \leq \overline{P}_{s}^{GHS_{FC}} H_{s,q}^{GHS_{FC}} \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.13}$$

To avoid the simultaneous charging and discharging of GHS, the following constraints are applied:

$$H_{s,q}^{GHS_{EL}} + H_{s,q}^{GHS_{FC}} \leq 1 \qquad \forall s \,\epsilon\, GHS,\ \forall q \,\epsilon\, Q \tag{3.14}$$

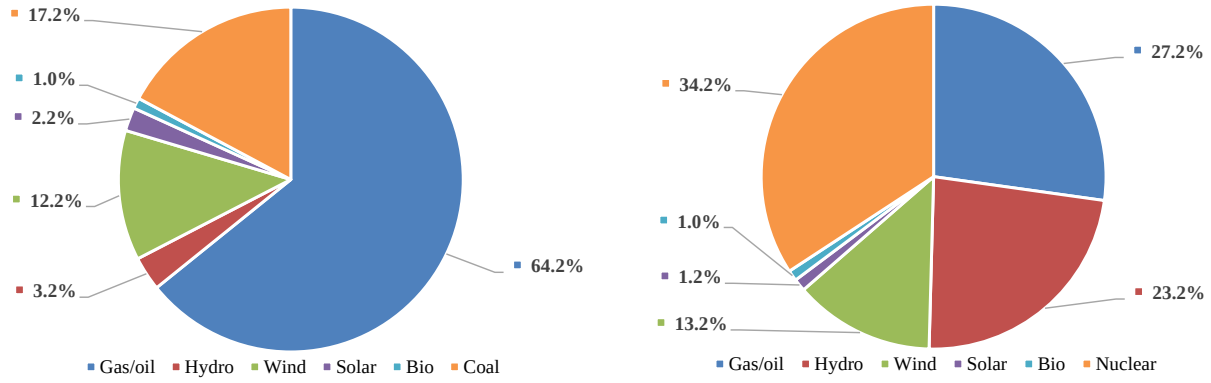
Green Hydrogen Constraints:

The energy consumed by electrolyzers during charging operation of GHSs must be supplied by the cleared dispatch of RES and hydro generation only, to ensure that the GHSs are net-zero CO_2 emissions resources. As primary aim of this work is to demonstrate the integration of GHSs as market participants, it is assumed that there will be a mutual contract/mechanism between GHS owners and ISO to ensure the energy consumption by GHSs are supplied through the clean resources only. This work focuses on determining the impact on the market settlement due to GHSs participation, the extra payments for such contracts are considered to be part of their bids/offers, and are not explicitly segregated and presented here. Few proposed mechanisms to ensure the clean energy consumption during charging operation of the GHSs could be: (a) co-locating GHSs at buses where RES and hydro generators are integrated and (b) having separate market prior to wholesale energy market similar to Green-Term Ahead Market (G-TAM) of India [157] wherein the trading of renewable energy is carried out.

$$\sum_{s \epsilon GHS} P_{s,q}^{GHS_{EL}} \leq \sum_{wg \epsilon WG} P_{wg,q}^{RES_{wg}} + \sum_{pv \epsilon PV} P_{pv,q}^{RES_{pv}} + \sum_{j \epsilon J_{hydro}} P_{j,q}^{Gen} \qquad \forall q \,\epsilon\, Q \tag{3.15}$$

Market Clearing and Other Constraints

These constraints ensure that the market cleared consumers' demands and gencos' supplies are within their respective maximum bid/offer quantities. These also include UC constraints such as ramp-rate limits, minimum up-time/down-time constraints, generation limits and coordination constraints. The detailed formulation of these constraints can be referred in [120]. The endpoint constraints are not considered in this work. By adding the endpoint constraints, it can be ensured that at the end of day the SOC would be at least equal to its start value; which can be extension of this model.



(a) System-1: Alberta (b) System-2: Ontario

Figure 3.1: Transmission-connected energy mix.

3.4 Case Studies, Results and Analyses

To examine the effectiveness and performance of the proposed model, the Alberta and Ontario provinces transmission-connected supply mix were considered (Fig. 3.1), considering the same percentage share of each fuel type resource, as these provinces possess in actual, [158, 159]. The total generation capacity was scaled-down to configure with the IEEE 24-bus Reliability Test System (RTS) [160, 161] with RES (wind and solar) for each province. These two provinces were shortlisted for study in this work since they have distinct spectrum of energy technologies' mix, Alberta's 81% generation capacity being fed by emission-intensive resources (Fig. 3.1(a)), while Ontario has 72% of its capacity from low-zero emission resources (Fig. 3.1(b)). The gencos' offers and consumers' bids are in three price-quantity pairs while those of RES are in a single price-quantity pair. There are 10 GHS units of distinct ratings, with a total capacity of 340 MW, located at ten different buses in both systems. These GHSs submit their bids (for charging mode) and offers (for discharging mode) in single price-quantity pair [151]. The proposed UMP-based DAM auction model is formulated as an MIP problem and solved using the CPLEX solver in General Algebraic Modeling System (GAMS) environment [162]. Various cases and scenarios are developed to investigate the impact of GHSs participation and consideration of carbon pricing in the electricity market settlement and emissions reduction, which are described in Table 3.1. The carbon price is considered to be 65 $[2]/tonnes for both systems under study, as per [5]. The data considered for performing the case studies in this chapter

[2]It is to be noted that all the costs in this chapter are in Canadian Dollars unless stated otherwise.

are given in Appendices A, B and C.

Table 3.1: Systems, Scenarios and Cases

Systems	
System-1	Alberta (emission-intensive resources dominant)
System-2	Ontario (low-emission resources dominant)
Scenarios	
Scenario-1	Considering emission cap
Scenario-2	Considering carbon pricing
Cases	
Case-1	Without GHS
Case-2	Considering GHS

3.4.1 Business As Usual (BAU)

This considers the base system for each, Alberta and Ontario, without any emission control strategies or GHSs, and serves as the reference for further analyses presented in subsequent subsections. The social welfare and system emissions obtained for Business As Usual (BAU) scenario for Alberta are $3,328,000 and 29.4 kTonne, respectively; while for Ontario, are $4,569,000 and 6.43 kTonne, respectively. Furthermore, when GHSs were included in the BAU scenario with their current cost metrics (typically cost of hydrogen as 3 USD/kg), it was observed that the GHSs were not cleared in the DAM settlement in either systems because of being an expensive resource.

3.4.2 Social Cost of Carbon (SCC) and Green Paradox

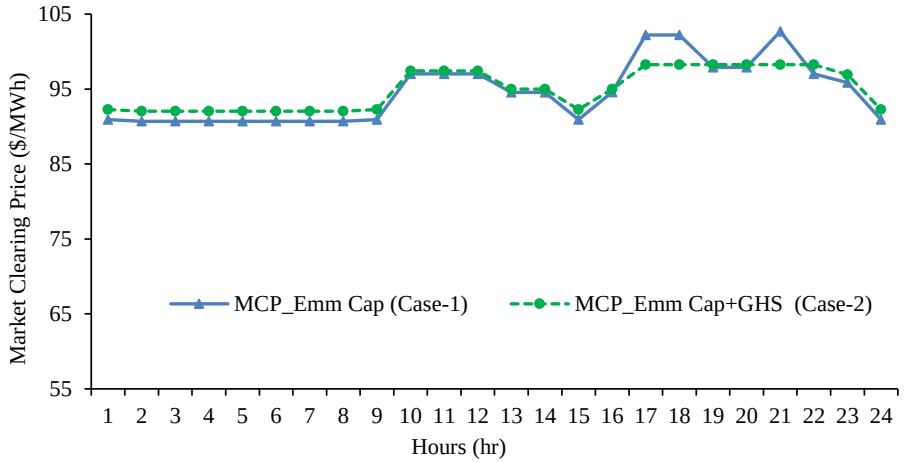
The Social Cost of Carbon (SCC) is well-recognized globally as a central concept to estimate the climate change damages in the Cost-Benefit Analysis (CBA) of climate change public policies and public investments, and is defined as marginal economic loss or cost caused when an additional ton of carbon or its equivalent is released into the environment [163–168]. It denotes the present-value of damage in monetary terms which can be further use as a benefit for policies/projects that induces a net carbon emissions reduction and/or can be added as a cost term for projects which lead to carbon emissions [169]. Many

countries have explored the role of carbon taxes or SCC and have developed their own ways for estimating it. In reported literature, various theories, approximation models and approaches are explored with different sets of assumptions and objectives [163–169]. An important concern which is being highlighted in the reported works is Green Paradox, which states that the policies or measures aiming towards carbon emissions reduction and climate change abatement, may result in reducing welfare and potentially increasing emissions in the near-term [169]. In reference [169], it was concluded that the carbon pricing seems to be a better way for regulating emissions as compared to other approaches such as subsidies to RES, etc., while avoiding the issue of Green Paradox. Thus, in this work, the author investigates the role of SCC in both approaches of being considered as (a) a benefit item to obtain gross social welfare which then may be distributed to consumers in some form of incentives/rebates, and (b) a cost term in the objective function of the mathematical model (in form of carbon pricing) to penalize the resources causing carbon emissions; these are discussed in detail in subsequent subsections.

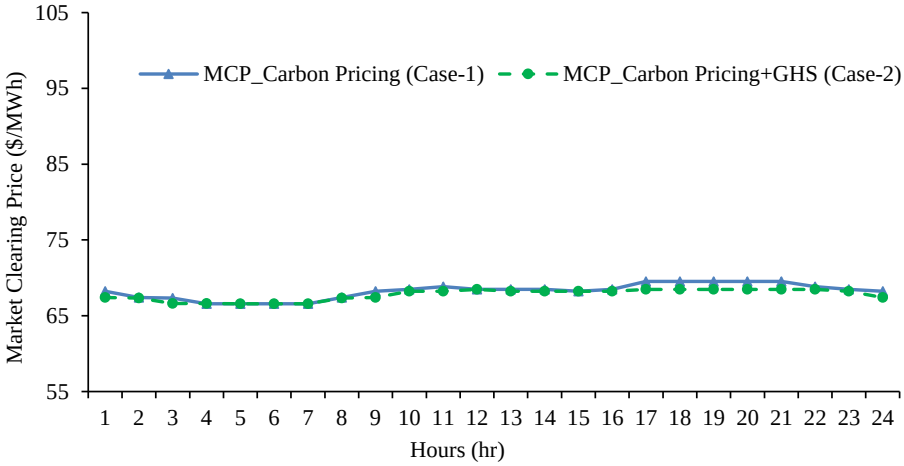
3.4.3 Studies Considering Emission Control Strategies

With the goal to achieve a net-zero CO_2 emissions grid, two potential emission control strategies are proposed herein, considering their ease of implementation and being realistic, namely, *emission cap* and *carbon pricing*. The emission cap is included as a constraint in the market settlement mathematical model while the carbon pricing strategy is included by modifying the model objective function. Fig. 3.2(a) shows the MCP profiles over 24-hr horizon obtained for Alberta when an additional constraint to cap the emissions (Scenario-1) to 60% of the existing emissions (base case) is considered. The two curves corresponds to cases without (Case-1) and with (Case-2) GHSs participation, respectively. The MCPs increased when an emission cap was included in both cases as compared to the base case, however, the spikes in energy prices during peak hours (17,18 & 21) were flattened in the latter case when GHSs participated (Case-2). This is due to the fact that GHSs discharge during these hours (as shown in Fig. 3.3(a)) to limit the price rise, as they are cheaper resources and do not contribute to emissions, being net-zero CO_2 emissions resources. While, Fig. 3.2(b) presents the Scenario-2 MCP plots when carbon pricing is included in the objective function considering the emission factors from each resource, in the market optimization model. It can be noted that consideration of carbon pricing increased the MCPs in comparison to base case, however the increase in Case-2 was flattened during peak hours as compared to Case-1 due to discharging operation of GHSs at those hours (Fig. 3.3(b)).

In Ontario, the MCPs increased when an emission cap of 80% was imposed (Scenario-1)

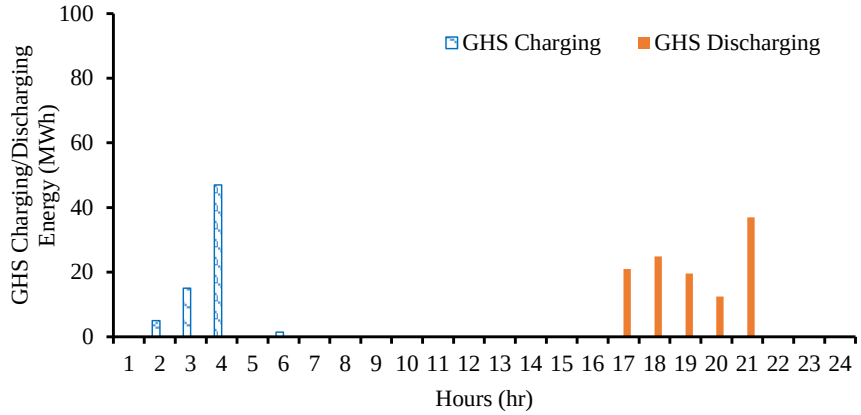


(a) Scenario-1: Considering emission cap

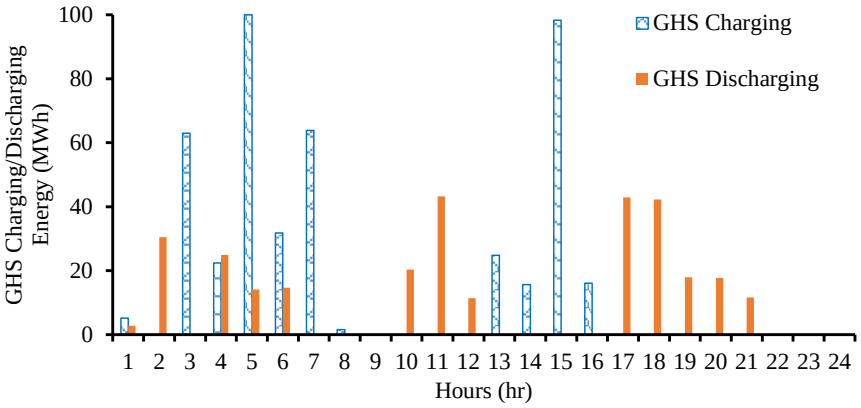


(b) Scenario-2: Considering carbon pricing

Figure 3.2: Market clearing price profiles for Alberta (System-1).

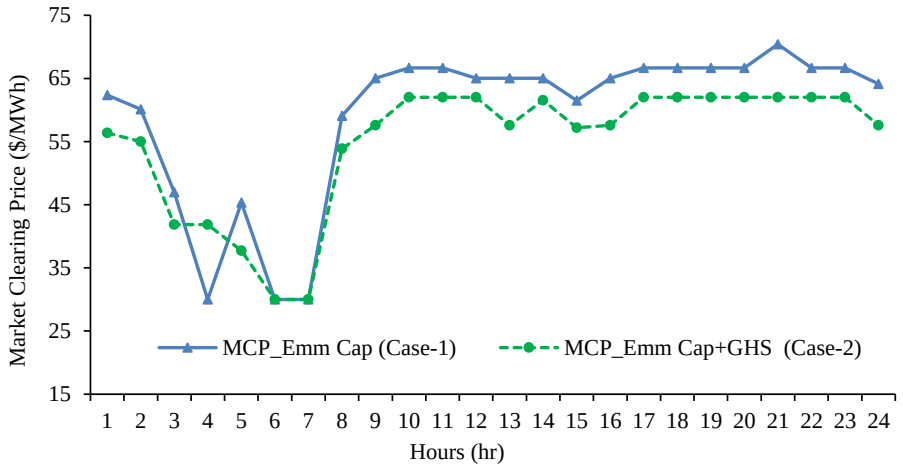


(a) Case-2, Scenario-1: Considering emission cap

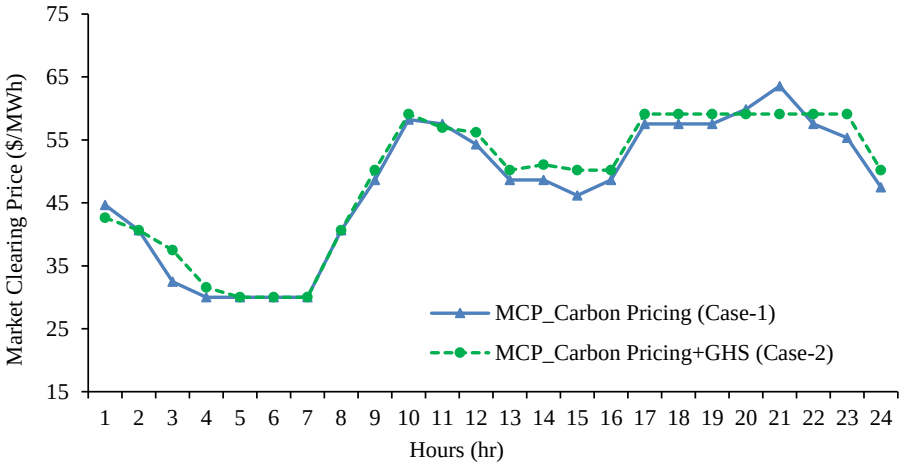


(b) Case-2, Scenario-2: Considering carbon pricing

Figure 3.3: GHS charging/discharging profiles for Alberta (System-1).

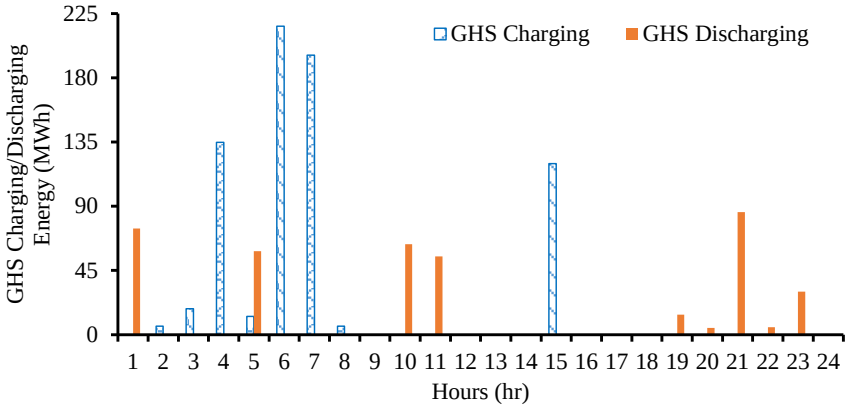


(a) Scenario-1: Considering emission cap

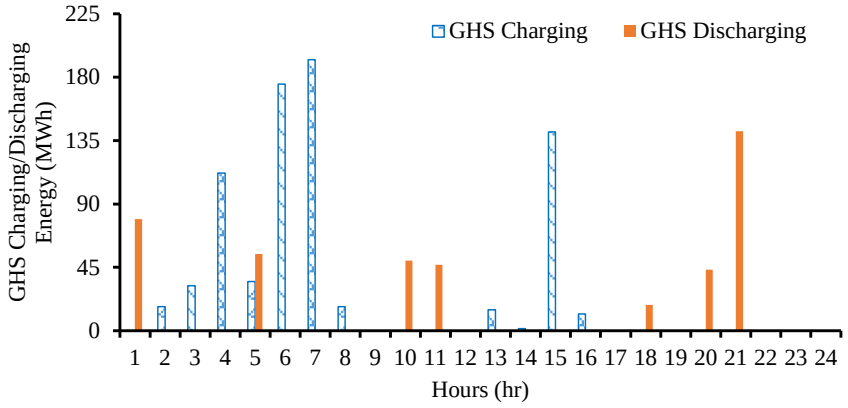


(b) Scenario-2: Considering carbon pricing

Figure 3.4: Market clearing price profiles for Ontario (System-2).



(a) Case-2, Scenario-1: Considering emission cap



(b) Case-2, Scenario-2: Considering carbon pricing

Figure 3.5: GHS charging/discharging profiles for Ontario (System-2).

in the market model. It can be noted from Fig. 3.4(a) that the price increase was lower when GHSs were included (Case-2) as compared to without considering them (Case-1). Moreover, GHSs assisted in flattening the MCP spikes during the peak hour (21). The small rise in MCPs during low demand hours (3-6) in case of GHSs participation (Case-2) as compared to Case-1, can be attributed to their charging operation (as shown in Fig. 3.5(a)). Fig. 3.4(b) presents the MCP plots for Scenario-2 for Ontario. It can be seen that in Case-2 the MCP profile flattens during peak hours (17-22) and alleviates spike at hour-21 as compared to Case-1. This is again due to the GHSs discharging operation during high price hours (as shown in Fig. 3.5(b)) which limits and/or alleviates such spikes in the energy prices. Moreover, it is anticipated that further reduced MCPs could be obtained in both scenarios for Case-2 if significant capacities of GHSs were deployed with respect to the overall system size and/or their bids/offers are modified incorporating the benefits and rebates received under schemes such as IRA 2022, 111 Hydrogen Shot, *etc.* The deployment of these steps could accelerate the transition to a decarbonized electricity sector for both systems.

The values of the emission cap of 60% for Alberta and 80% for Ontario were chosen based on the following two reasons: (a) our studies revealed that when the emission cap was below 60%, the Alberta DAM model was too constrained and did not yield a feasible solution. Accordingly, for Alberta the lowest emission cap for which a feasible solution was obtained, at 60%, was chosen. In the same way, for Ontario DAM, the minimum feasible emission cap was 75%, and consequently, 80% was chosen. And (b) references [5,6] provide the historical and forecasted emission profiles from the electricity sector for the period 2005 to 2040. The emission caps can also be estimated from the emission data and projected emissions for two consecutive years, say 2022 and 2023, which yielded similar values as chosen in this chapter.

It can be observed that there is a considerable difference in price profiles between Scenario-1 (emission cap) and Scenario-2 (carbon pricing) for both systems, Alberta and Ontario, as depicted in Fig. 3.2(a) & (b) and Fig. 3.4(a) & (b). Note that an emission cap is a hard constraint, and enforces the more expensive low-emission resources to be dispatched, in Scenario-1, in lieu of the cheaper emission-intensive resources, irrespective of the total system cost. This increases the system's marginal cost and hence the market price. On the other hand, Scenario-2 with carbon pricing considers an additional cost in the objective function, and an optimal solution is arrived at, wherein the emission-intensive resources are not substituted as much as in Scenario-1 by expensive low-emission resources since their offer prices are higher than the carbon price considered (65 $/tonne). This effect is more observed in the Alberta system with 81% of its capacity being emission-intensive resources while much less effect in Ontario which has 28% of its capacity emission-intensive

resources.

Table 3.2 presents a summary of some market clearing results of the UMP-based DAM for both the systems under study. For Alberta, it can be noted that the social welfare increased in both scenarios in Case-2 as compared to Case-1; thus GHSs participation yielded higher social welfare. The consideration of emission cap (Scenario-1) restricted the total emissions to 60% (17.64 kTonne) of the base case emissions (29.4 kTonne). It can be seen that GHSs participated in the market more through discharging operation than charging, in Scenario-1 to satisfy the emissions cap. The social welfare decreased in Scenario-2 for each case in comparison to Scenario-1 due to the consideration of carbon pricing. The inclusion of carbon pricing in the market model resulted in reduction of emissions (20.9 kTonne) as compared to base case emissions (29.4 kTonne). The GHSs participation in Scenario-2 was considerably higher than Scenario-1 because their bids/offers were in the range of carbon price and MCPs which resulted in their increased participation while, in Scenario-1 more gas-fired generators had to be dispatched to satisfy the emission cap and other UC constraints, hence limiting the GHSs participation.

For Ontario, the social welfare decreased by a small amount in Case-2 as compared to Case-1 for Scenario-1 contrary to Alberta results. However, this can be attributed to decrease in the total emissions, 4.92 kTonne in Case-2 over 5.14 kTonne in Case-1. For same emissions amount, the social welfare will be higher in Case-2. And for Scenario-2, the observations remain same as discussed for Alberta. The emission cap of 80% of the base case emissions (6.43 kTonne) restricted the emissions to 5.14 kTonne in Scenario-1. Carbon pricing consideration resulted in emissions reduction (6.1 kTonne, Scenario-2) as compared to the base case for Ontario as well and the social welfare also decreased. Interestingly, it can be observed that GHSs participation in Ontario was higher as compared to Alberta. This is mainly because of the *Green Hydrogen Constraint* (3.15), described in Section 3.3.2, which limits the consumption of GHSs through only cleaner resources. Since, Ontario have more cleaner resources as compared to Alberta, the GHSs participation is higher for the former. It is anticipated that if this constraint is relaxed to incorporate other colors of hydrogen systems, the participation of such hydrogen systems will increase in Alberta significantly. It can be inferred from Table 3.2 that out of two proposed emission control strategies, emission cap was more effective strategy when the impact on social welfare and reduction in system emissions are considered to be determining factors; on the other hand, carbon pricing was the preferred approach if the impact on MCP is the determining attribute, in both Alberta and Ontario systems.

Table 3.2: Summary of Market Clearing Results of DAM (aggregated over 24-hours)

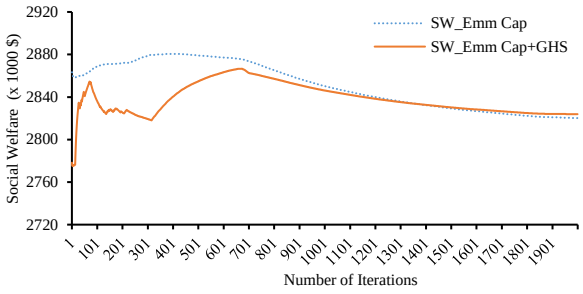
System-1: Alberta					
		Case-1: Without GHS		*Case-2: Considering GHS*	
	BAU	*Scenario-1 (Emission Cap)*	*Scenario-2 (Carbon Pricing)*	*Scenario-1 (Emission Cap)*	*Scenario-2 (Carbon Pricing)*
Social Welfare (x1000 $/day)	3,328	2,639	1,515	2,644	1,526
Total Emissions (kTonne/day)	29.40	17.64	20.96	17.64	20.88
Demand Cleared (MWh/day)	38,622				
GHS Charging (MWh/day)	-	-	-	69	443
GHS Discharging (MWh/day)	-	-	-	115	295
System-2: Ontario					
		Case-1: Without GHS		*Case-2: Considering GHS*	
	BAU	*Scenario-1 (Emission Cap)*	*Scenario-2 (Carbon Pricing)*	*Scenario-1 (Emission Cap)*	*Scenario-2 (Carbon Pricing)*
Social Welfare (x1000 $/day)	4,569	4,449	4,158	4,434	4,172
Total Emissions (kTonne/day)	6.43	5.14	6.13	4.92	6.06
Demand Cleared (MWh/day)	52,256				
GHS Charging (MWh/day)	-	-	-	710	750
GHS Discharging (MWh/day)	-	-	-	392	434

3.4.4 Sensitivity Analyses

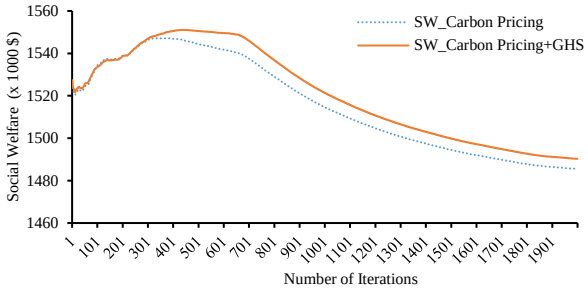
Detailed sensitivity studies are carried out to evaluate the performance of the proposed mathematical model without and with the inclusion of GHS, and considering RES uncertainties and the two emission control strategies, emission cap and carbon pricing. The emission cap limiting value and the choice of carbon price value are varied over a range. The GHS operational characteristics, such as storage tanks' initial moles content, are also varied.

Effect of RES Uncertainties

The MCS is one of the most implemented technique to investigate the behaviour of the model based on repeated random sampling and statistical analysis to estimate potential outcomes [170]. To evaluate the model performance and effectiveness, MCS is carried out over 2,000 samples by considering a normal distribution function with mean and standard

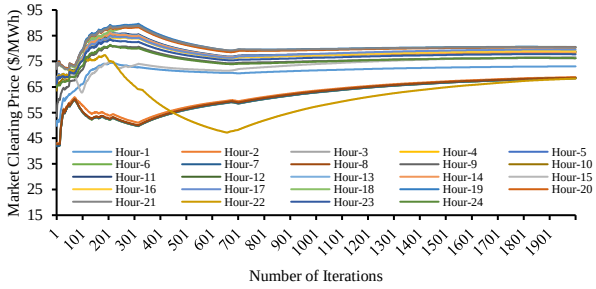


(a) Scenario-1: Considering emission cap

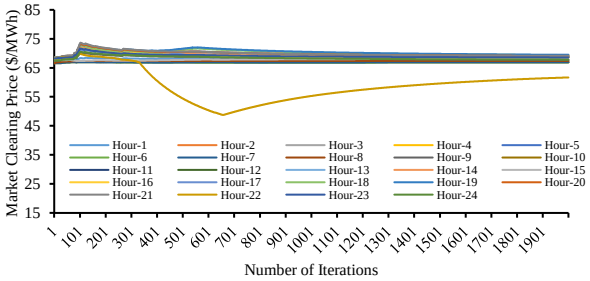


(b) Scenario-2: Considering carbon pricing

Figure 3.6: Social welfare profiles considering RES uncertainties for Alberta (System-1).



(a) Scenario-1: Considering emission cap

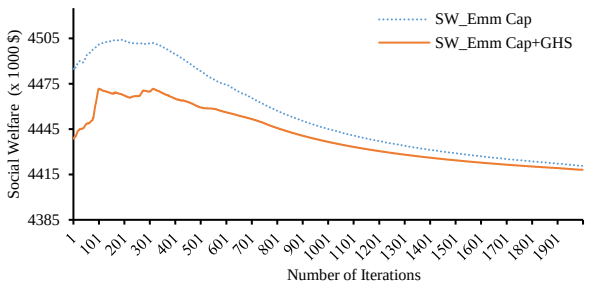


(b) Scenario-2: Considering carbon pricing

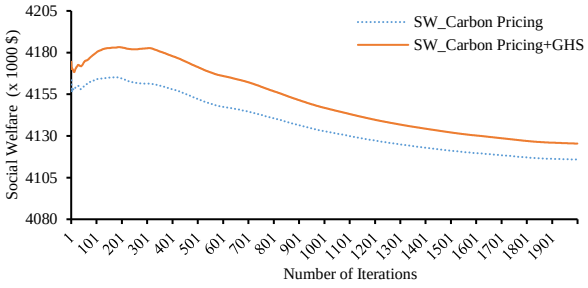
Figure 3.7: MCP considering RES uncertainties for Alberta (System-1).

deviation for the RES generation (wind and solar) in DAM settlements, for each system, Ontario and Alberta. For the Alberta system, Fig. 3.6(a) presents the expected social welfare without and with GHS for Scenario-1 (considering emission cap) and Fig. 3.6(b) shows the social welfare for without/with GHS for Scenario-2 (considering carbon pricing), demonstrating their convergence. Fig. 3.7 presents the convergence of hourly MCPs without and with GHS in each of the scenarios, for Alberta.

On the other hand, for the Ontario system studies, Fig. 3.8 presents the convergence of the expected social welfare, without and with GHS, in each of the scenarios. Fig. 3.9 demonstrate the convergence of Ontario's hourly MCPs without and with GHS, for both scenarios.

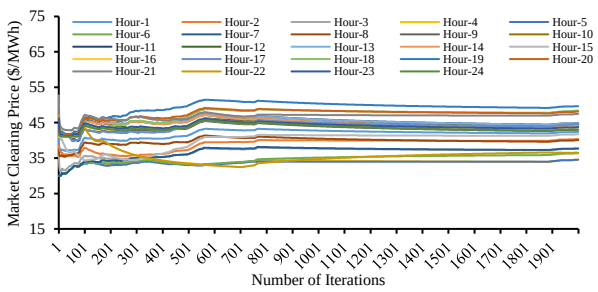


(a) Scenario-1: Considering emission cap

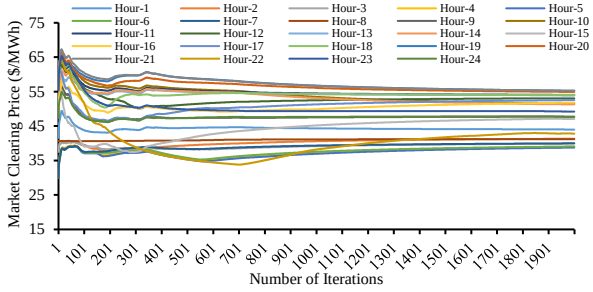


(b) Scenario-2: Considering carbon pricing

Figure 3.8: Social welfare profiles considering RES uncertainties for Ontario (System-2).

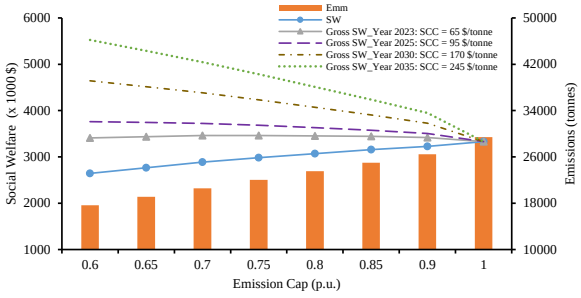


(a) Scenario-1: Considering emission cap

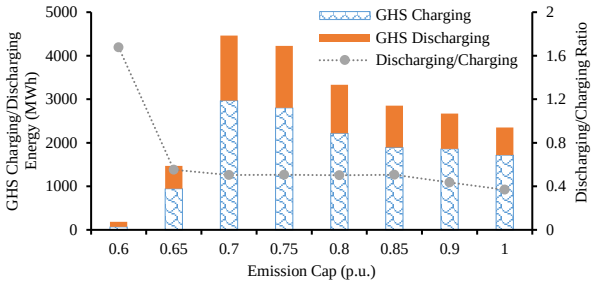


(b) Scenario-2: Considering carbon pricing

Figure 3.9: MCP profiles considering RES uncertainties for Ontario (System-2).

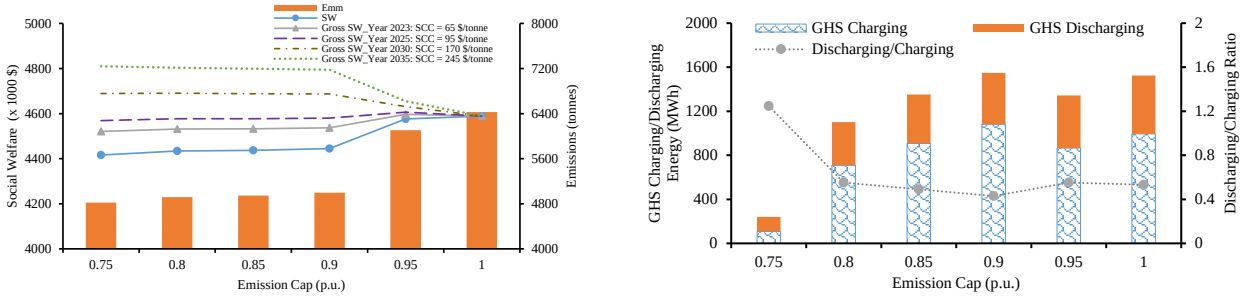


(a) Social welfare & Emissions



(b) GHS charging/discharging

Figure 3.10: Effect of emission cap for Alberta (System-1).



(a) Social welfare & Emissions

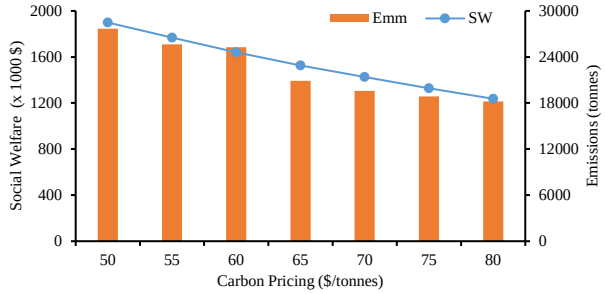
(b) GHS charging/discharging

Figure 3.11: Effect of emission cap for Ontario (System-2).

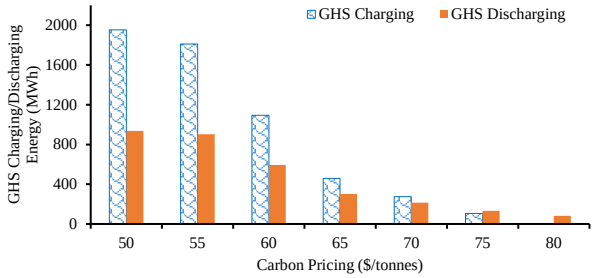
Effect of Emission Cap

For Alberta, the emission cap is varied over a range from 0.6 to 1 per unit (p.u.), *i.e.* emissions are varied in range of 60% to 100% of BAU emissions, and its effect on the social welfare and GHS charging & discharging operations are examined. It is noted from Fig. 3.10 that as the emission cap is tightened, the social welfare decreases while the GHS discharging to charging ratio gradually increases, up to the cap value of 0.7 p.u., and beyond that, charging/discharging operations are significantly reduced. In the case of Ontario, the emission cap was varied from 0.75 to 1 p.u. and the results show that the social welfare decreased as the emission cap was tightened (Fig. 3.11(a)) and the GHS discharging/charging ratio increased (Fig. 3.11(b)).

From Fig. 3.10(a) and Fig. 3.11(a) for both Alberta and Ontario, the Green Paradox effect is observed *i.e.* with the reduction in carbon emissions the social welfare also decreased. From system operator or market operator perspective, the conventional approach of calculating social welfare via the market settlement does not consider the benefit from net carbon emissions reduction and hence, the social welfare decreases with emissions reduction due to low-zero emitting resources being cleared which are costlier. However, if the gross social welfare is calculated by adding the benefit term using the SCC as discussed in subsection 3.4.2, then it can be seen that the social welfare increased with the reduction in carbon emissions. The gross social welfare can be calculated as *Gross SW = SW + (Net Emission Reduction x SCC)*. The effect of choice of SCC on gross social welfare with varying limit of emission cap is demonstrated in Fig. 3.10(a) and Fig. 3.11(a) for Alberta and Ontario, respectively wherein the SCC is increased annually by 15 $/tonnes from year 2023 to 2035 [5].

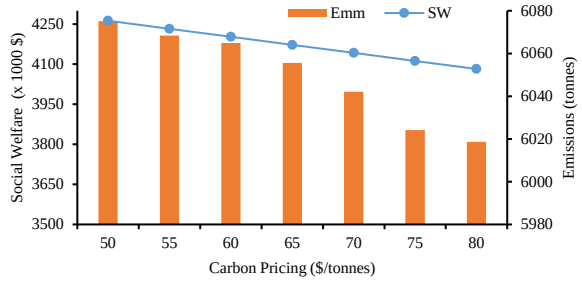


(a) Social welfare & Emissions

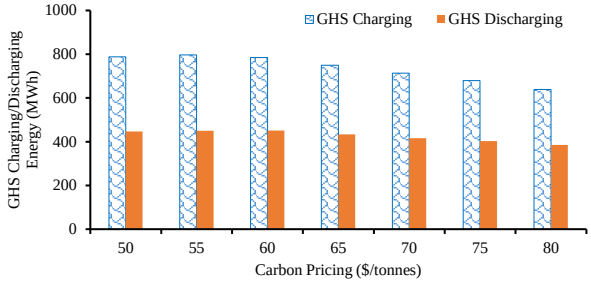


(b) GHS charging/discharging

Figure 3.12: Effect of carbon pricing for Alberta (System-1).



(a) Social welfare & Emissions

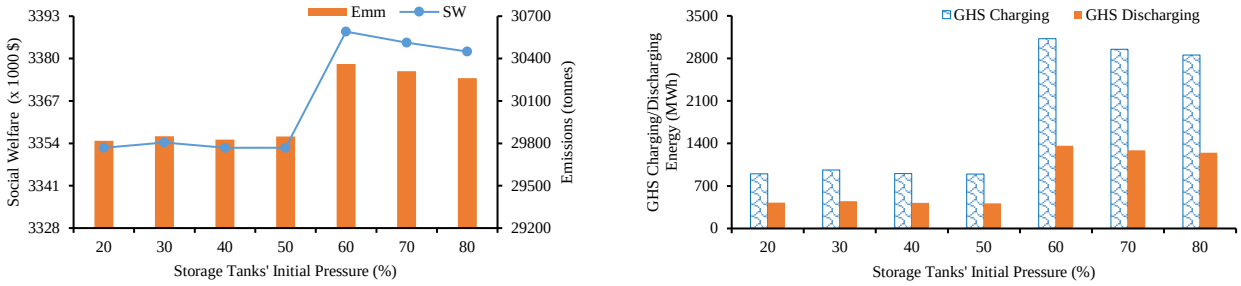


(b) GHS charging/discharging

Figure 3.13: Effect of carbon pricing for Ontario (System-2).

Effect of Carbon Pricing

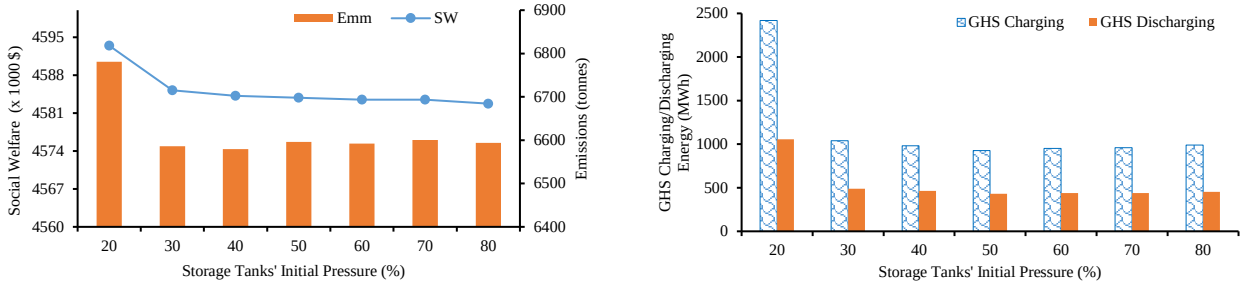
A study was performed to examine the impact of carbon pricing on system attributes by varying the price from 55 $/tonnes to 80 $/tonnes in steps of 5 $/tonnes. From Fig. 3.12(a) and Fig. 3.13(a), it can be observed that with increase in carbon pricing, the social welfare and system emissions reduced in both Alberta and Ontario. The reduction in case of Alberta was more significant (in the range of 50%) while in Ontario the reduction was lower, in the range of 5%. This is because the share of low/zero emission resources in the energy mix of Ontario is 72%, as compared to 19% in Alberta. With increase in carbon price, the GHS charging/discharging operations were reduced, more noticeably in Alberta (Fig. 3.12(b)) as compared to Ontario (Fig. 3.13(b)).



(a) Social welfare & Emissions

(b) GHS charging/discharging

Figure 3.14: Effect of storage tanks' initial pressure for Alberta (System-1).



(a) Social welfare & Emissions

(b) GHS charging/discharging

Figure 3.15: Effect of storage tanks' initial pressure for Ontario (System-2).

Effect of Changing the Initial Conditions of GHS Storage Tanks

Analysis was carried out to examine the effect of varying the initial conditions of the GHS storage tanks; varying the initial pressure (moles content) over a range from 20% to 80% of its maximum capacity. Also, the following end-point constraint is included in the mathematical model to ensure that storage tank pressure at the end of the day is greater than or equal to its initial value, in preparation for the next day:

$$Pr^{GHS_{ST}}_{s,'0'} \leq Pr^{GHS_{ST}}_{s,'24'} \quad \forall s \, \epsilon \, GHS \tag{3.16}$$

From Fig. 3.14(a), it can be noted that for Alberta, with the increase in initial moles content (pressure) of GHS storage tanks, the social welfare and system emissions remained at a fairly uniform level up to 50% and increased significantly at 60%. This is because with higher initial moles content, the total generation cleared from gencos are higher as compared to that with lower inital moles content, which leads to higher charging of GHSs and

hence increased social welfare but at the price of higher system emissions. Alternatively, when the same sensitivity analysis is carried out by imposing emission constraint in the model where emissions are restricted to that obtained in case of 20% then, with increase in the initial pressure of GHS storage tanks the social welfare reduced; for instance the social welfare obtained are $3,352,625 and $3,312,832 at 20% and 60% inital pressure of tanks, respectively. In Ontario, the social welfare and system emissions decreased with the increase in initial moles content of GHS tanks (Fig. 3.15(a)). Similar effect is observed on charging/discharging operations of the GHS units for both systems, Alberta and Ontario, as presented in Fig. 3.14(b) amd Fig. 3.15(b), respectively.

3.5 Summary

In this chapter, a new framework and a comprehensive mathematical model were proposed which integrated GHSs in an UMP-based day-ahead electricity market. The effect of considering two emission control strategies, namely emission cap and carbon pricing, on electricity market settlements were investigated in detail. The effectiveness and performance of the model was evaluated by considering the IEEE 24-bus RTS and the supply mix of two real power systems with distinct characteristics, that of the Alberta and Ontario provinces of Canada. The model was comprehensively formulated to take into account the effect of carbon emissions, physical and operational characteristics of market participants. It was noted that in the base scenario without any emission control strategy, the GHSs were not cleared in the DAM settlement due to their expensive cost metrics. However, GHSs were cleared in each system when emission control strategies were introduced, these being net-zero CO_2 emissions resources. The consideration of carbon pricing and emission cap in the market model helped in reducing the system emissions although yielding higher MCPs and reduced social welfare as compared to the BAU case. The inclusion of GHSs helped in smoothing the effect of inclusion of carbon pricing and emission cap on the MCPs, by flattening the MCP profiles considerably during peak hours (17-21). From the results, it was observed that the participation of GHSs improved the social welfare for all scenarios; in Alberta, it increased by 5,000 $/day and by 11,000 $/day in Scenario-1 and Scenario-2, respectively while in Ontario, the change in social welfare was 15,000 $/day and 14,000 $/day in Scenario-1 and Scenario-2, respectively.

It was observed from the studies presented that emission cap was more effective strategy when the impact on social welfare and reduction in system emissions are considered to be determining factors; on the other hand, carbon pricing was the preferred approach if the impact on MCP is the determining attribute, in both Alberta and Ontario systems. From

the MCS studies considering RES (wind and solar) uncertainties, it was noted that both systems in each scenario converged to their expected values. From the sensitivity analyses, it was seen that as the emission cap was relaxed (0.6 to 1 p.u for Alberta and 0.75 to 1 p.u. for Ontario) the social welfare increased while the GHS discharging to charging ratio decreased. When the SCC was increased in increments of 15 $/tonnes from year 2023 to 2035, the system emissions decreased while the gross social welfare increased, with more significant effect observed in Alberta as compared to Ontario. It was observed that when the carbon price was considered and varied from 55 $/tonnes to 80 $/tonnes in steps of 5 $/tonnes, the social welfare and system emissions both decreased, with more noticeable impact seen in Alberta as compared to Ontario. It was noted that when the initial condition of GHSs' storage tanks was varied (20% to 80% of its maximum capacity), then for Alberta with higher initial pressure, the social welfare and total emissions increased while they decreased for Ontario. It is anticipated that with reduction in GHS cost metrics and technology development, their penetration in electricity markets will increase, resulting in lowering of emissions and MCPs. GHS possesses generation, storage and consumption components which can assist the system operators to meet the complex needs of the power grid and help in achieving a net-zero GHG emissions grid. The main contents of this chapter have been published in [171, 172].

Chapter 4

Integration of Green Hydrogen Systems in LMP-based Day-ahead Electricity Markets[1]

4.1 Nomenclature

Sets & Indices

i, j	Buses, $i, j \in J$.
f	HEFR units, $f \in HR$.
g	Generators (gencos), $g \in G$.
k	Time (hour), $k \in K$.
b	Blocks of consumer bids, $b \in N_{CB}$.
o	Blocks of gencos offers, $o \in N_{GO}$.
wg	Wind facilities, $wg \in WG$.
pv	Solar (PV) facilities, $pv \in PV$.

[1]Parts of this chapter have been published in:

- A. Goyal and K. Bhattacharya, "Integration of Green Hydrogen-based Loads, Storage and Generation in Electricity Markets", *2024 IEEE Power & Energy Society General Meeting*, Seattle, USA, July 2024.

Parameters

C^{C}	Consumers bid price, \$/MWh.
C^{Genco}	Gencos energy offer price, \$/MWh.
$C^{Genco_{SU/DN}}$	Gencos start-up/shut-down cost, \$.
$C^{R_{pv/wg}}$	PV/wind energy offer price, \$/MWh.
$C^{HR_{ch/Dch}}$	HEFRs energy bid/offer price, \$/MWh.
B	Element of susceptance matrix, p.u.
$\overline{N}^{HR_{ch}}$	Maximum number of hydrogen moles produced by the electrolyzer, mol.
$\eta^{HR_{ch/Dch}}$	HEFR charge/discharge mode efficiency, %.
LHV^{HR}	Minimum thermal energy content of hydrogen, MW/mol.
$\overline{P}^{HR_{ch}}$	Maximum power of the electrolyzer, MW.
$\underline{P}^{HR_{ch}}$	Minimum power of the electrolyzer, MW.
$\overline{Pr}^{HR_{ST}}$	Maximum pressure of the storage tank, Pa.
$\underline{Pr}^{HR_{ST}}$	Minimum pressure of the storage tank, Pa.
$\overline{P}^{HR_{Dch}}$	Maximum power generated by fuel cell, MW.
$\underline{P}^{HR_{Dch}}$	Minimum power generated by fuel cell, MW.
$\overline{N}^{HR_{Dch}}$	Maximum number of hydrogen moles consumed by the fuel cell, mol.
$\overline{PFlow}$	Maximum transmission line capacity, MW.
$Temp^{HR_{ST}}$	Average temperature of the storage tank, K.
$Vol^{HR_{ST}}$	Volume of the storage tank, m^3.
$\Re_{gas}$	Constant of gases, $JK^{-1}mol^{-1}$.

Variables

P^{C}	Demand cleared, MW.
P^{Genco}	Gencos offer cleared for energy, MW.
$P^{R_{pv/wg}}$	PV/wind generation cleared, MW.

$P^{HR_{ch/Dch}}$	HEFRs charging/discharging power, MW.
U, V	1, if gencos start/shut-down, 0 otherwise.
P^{loss}	Power loss in the transmission line, MW.
δ	Voltage angle, radian.
$H^{HR_{ch/Dch}}$	1, if HEFR charging/discharging, 0 otherwise.
$Pr^{HR_{ST}}$	Pressure of the HEFR storage tank, Pa.
$N^{HR_{ch}}$	Hydrogen moles produced by HEFR, mol.
$N^{HR_{Dch}}$	Hydrogen moles consumed by HEFR, mol.

4.2 Introduction

In this chapter, a generic framework and a detailed mathematical model to integrate HEFRs in an LMP-based DAM, complying with the existing market rules are presented. The proposed model takes into account the physical and operational characteristics of the HEFR processes, as well as minimum size criteria, energy arbitrage and market constraints. Comprehensive case studies and sensitivity analysis are carried out to examine the impact of integration of HEFRs on market settlement, marginal prices and system emissions.

4.3 Integration of HEFRs in Electricity Markets

A HEFR unit comprises three major components namely, electrolyzer, storage tanks and fuel cells. It can operate in two different modes: charging mode, wherein the electrolyzer utilizes water and RES-based electricity to produce green hydrogen, referred as PtH process and the produced hydrogen is stored inside tanks; and discharging mode, which produces emission free electricity by using the stored hydrogen via fuel cells, and is termed as HtP process. The proposed novel LMP-based auction model enables HEFRs to participate in the electricity markets, in an equitable manner, as other market participants (Fig. 4.1). A grid-scale, privately owned HEFR is considered, which bids to buy energy for PtH operation (charging mode) and offers to sell electricity in the wholesale market through its HtP process. The developed market auction model including HEFR is inspired by the guidelines developed in FERC Order 841 and Order 2222 which encourages ESSs and DERs to participate in electricity markets.

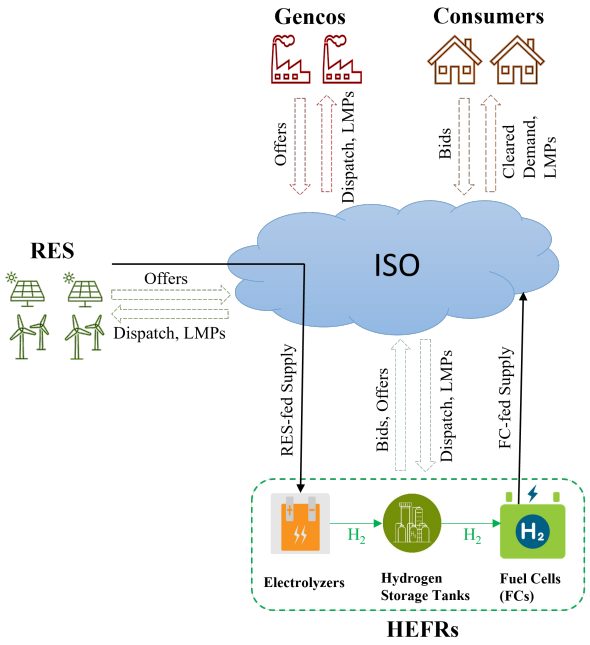


Figure 4.1: Framework for HEFR integrated DAM

4.4 Mathematical Model

Objective Function

To maximize the social welfare:

$$S = \underbrace{\sum_{k\epsilon K}\sum_{j\epsilon J}\sum_{b\epsilon N_{CB}}(C^{C}_{b,j,k}P^{C}_{b,j,k})}_{\text{(Consumers' Gross Surplus)}} + \underbrace{\sum_{k\epsilon K}\sum_{f\epsilon HR}(C^{HR_{ch}}_{f,k}P^{HR_{ch}}_{f,k})}_{\text{(HEFRs' Charging Surplus)}} - \underbrace{\sum_{k\epsilon K}\sum_{wg\epsilon WG}(C^{R_{wg}}_{wg,k}P^{R_{wg}}_{wg,k})}_{\text{(Energy Supply Costs from Wind)}}$$
$$- \underbrace{\sum_{k\epsilon K}\sum_{pv\epsilon PV}(C^{R_{pv}}_{pv,k}P^{R_{pv}}_{pv,k})}_{\text{(Energy Supply Costs from Solar (PV))}} - \underbrace{\sum_{k\epsilon K}\sum_{f\epsilon HR}(C^{HR_{Dch}}_{f,k}P^{HR_{Dch}}_{f,k})}_{\text{(HEFRs' Discharging Costs)}} - \underbrace{\sum_{k\epsilon K}\sum_{g\epsilon G}\sum_{o\epsilon N_{GO}}(C^{Genco}_{o,g,k}P^{Genco}_{o,g,k})}_{\text{(Gencos' Energy Supply Costs)}}$$
$$- \underbrace{\sum_{k\epsilon K}\sum_{g\epsilon G}(C^{Genco_{SU}}_{g,k}U_{g,k} + C^{Genco_{DN}}_{g,k}V_{g,k})}_{\text{(Gencos' Start-up and Shut-down Costs)}} \quad (4.1)$$

The first and second terms in (4.1) represent the gross surplus of consumers and the

HEFR in charging mode, respectively. The third and fourth terms denote the energy supply cost from wind and PV, respectively. The fifth term represents the HtP process cost (discharging cost) of the HEFRs for electricity production. The sixth term denotes the energy supply cost of gencos, and the seventh term denotes their start-up and shut-down costs. The objective function is subjected to the following set of constraints.

Demand-Supply Balance

This ensures the demand-supply balance at a bus at each hour; dc load flow equations are used, including line losses based on a linearized technique [120].

$$\sum_{g\epsilon G_j} P_{g,k}^{Genco} + \sum_{wg\epsilon WG_j} P_{wg,k}^{R_{wg}} + \sum_{pv\epsilon PV_j} P_{pv,k}^{R_{pv}} + \sum_{f\epsilon HR_j} P_{f,k}^{HR_{Dch}} - \sum_{f\epsilon HR_j} P_{f,k}^{HR_{ch}} - P_{j,k}^{C} = \sum_{i\epsilon J}(0.5P_{j,i}^{loss} + B_{j,i}(\delta_{j,k} - \delta_{i,k})) \quad \forall j \,\epsilon\, J,\ \forall k \,\epsilon\, K \tag{4.2}$$

HEFR Energy Arbitrage and Operational Constraints

HEFR PtH- Electrolyzer Constraints: The relationship between the number of hydrogen moles produced and the electric power drawn by the electrolyzer is given by,

$$N_{f,k}^{HR_{ch}} = \frac{\eta_f^{HR_{ch}} P_{f,k}^{HR_{ch}}}{LHV^{HR}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.3}$$

The maximum number of hydrogen moles that can be produced by the electrolyzer are given by the following constraint:

$$N_{f,k}^{HR_{ch}} \leq \overline{N}_f^{HR_{ch}} H_{f,k}^{HR_{ch}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.4}$$

The maximum and minimum power consumption limits of the electrolyzer are given as follows:

$$\underline{P}_f^{HR_{ch}} H_{f,k}^{HR_{ch}} \leq P_{f,k}^{HR_{ch}} \leq \overline{P}_f^{HR_{ch}} H_{f,k}^{HR_{ch}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.5}$$

HEFR Storage- Storage Tank Constraints: Based on the number of hydrogen moles generated in the PtH process and that utilized by the fuel cell units in HtP, the following

constraints denote the change in pressure of the storage tanks across two consecutive time intervals:

$$Pr_{f,k}^{HR_{ST}} - Pr_{f,k-1}^{HR_{ST}} = \frac{\Re_{gas} Temp_f^{HR_{ST}}}{Vol_f^{HR_{ST}}}(N_{f,k}^{HR_{ch}} - N_{f,k}^{HR_{Dch}}) \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.6}$$

The maximum and minimum limits of the storage tanks' pressure are given by the following equation:

$$\underline{Pr}_f^{HR_{ST}} \leq Pr_{f,k}^{HR_{ST}} \leq \overline{Pr}_f^{HR_{ST}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.7}$$

The following endpoint constraint ensures that the storage tanks' pressure (correspondingly moles content) at the end of each day is at least equal to the initial value, for the next day:

$$Pr_{f,'0'}^{HR_{ST}} \leq Pr_{f,'24'}^{HR_{ST}} \quad \forall f \,\epsilon\, HR \tag{4.8}$$

HEFR HtP- Fuel Cell Constraints: The relationship between the number of hydrogen moles utilized and the power generated by the fuel cells is given by,

$$N_{f,k}^{HR_{Dch}} = \frac{P_{f,k}^{HR_{Dch}}}{\eta_f^{HR_{Dch}} LHV^{HR}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.9}$$

The number of hydrogen moles utilized by the fuel cells are limited by the fuel cell design:

$$N_{f,k}^{HR_{Dch}} \leq \overline{N}_f^{HR_{Dch}} H_{f,k}^{HR_{Dch}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.10}$$

The maximum and minimum power generation limits of the fuel cell unit are given by,

$$\underline{P}_f^{HR_{Dch}} H_{f,k}^{HR_{Dch}} \leq P_{f,k}^{HR_{Dch}} \leq \overline{P}_f^{HR_{Dch}} H_{f,k}^{HR_{Dch}} \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.11}$$

The simultaneous charging and discharging operations of a HEFR is prevented by the following constraints:

$$H_{f,k}^{HR_{ch}} + H_{f,k}^{HR_{Dch}} \leq 1 \quad \forall f \,\epsilon\, HR,\ \forall k \,\epsilon\, K \tag{4.12}$$

Emission Free Hydrogen Production Constraints: The hydrogen produced by PtH process via the electrolyzer needs power which can be supplied from any generation resource, but the hydrogen so produced may not be carbon-neutral (*i.e., green*). One of the motivations

to consider HEFRs, apart from being a flexible resource, is their potential as an emission free resource which can help achieve the decarbonization goals. The following constraint ensures that the energy consumed in the PtH process is supplied by emission free resources such as PV, wind, hydro, etc.

$$\sum_{f \epsilon HR} P_{f,k}^{HR_{ch}} \leq \sum_{wg \epsilon WG} P_{wg,q}^{R_{wg}} + \sum_{pv \epsilon PV} P_{pv,q}^{R_{pv}} + \sum_{g \epsilon G_{hydro}} P_{g,k}^{Genco} \quad \forall k \, \epsilon \, K \tag{4.13}$$

It is assumed that in order to comply with the above constraint, there must be a contract between the ISO and HEFR owner for green electricity for its PtH process. The HEFR energy bid price $C^{HR_{ch}}$ is expected to internalize this contract price. Since the present work focuses on examining integration of HEFRs into auction markets, the contract design aspects are not explored here.

Transmission Line Limits

These constraints ensure that the line flows are within their line capacity limits.

$$B_{j,i}(\delta_{j,k} - \delta_{i,k}) \leq \overline{PFlow}_{j,i} \qquad \forall j, i \, \epsilon \, J, \, \forall k \, \epsilon \, K \tag{4.14}$$

Market Clearing, Coordination and Other Constraints

These include coordination constraints which ensure appropriate transition of UC states with unit start-up and shut-down, ramping, minimum up/down time constraints, etc. These also include constraints to ensure the cleared gencos' supplies and consumers' demands are within their respective offer/bid quantities. Although these constraints are considered in the proposed market model, they are not presented here and can be referred in [120].

4.5 Results and Discussions

The proposed model including HEFRs was tested on the IEEE 24-bus RTS [160, 161] with RES (PV and wind). The forecast PV and wind generation profiles, and transmission-connected supply were considered from Alberta, Canada, which comprises 65% gas/oil capacity, 17% coal, 12% wind, 3% hydro, 2% solar and 1% biomass [173]. About 82% of the installed capacity are carbon emission-intensive resources. The consumers bids and

gencos offers are in three price-quantity pairs, while those of HEFRs and RES are in single price-quantity pair. There are 10 HEFR units connected at different buses, of distinct ratings of electrolyzer, storage tank and fuel cell, and accounting for 10% of the total system capacity. The data considered for performing the case studies in this chapter are given in Appendices A, B and C. The proposed LMP-based DAM auction model is formulated as an MIP problem and solved using the CPLEX solver in GAMS environment [162]. In order to investigate the impact of HEFR inclusion on market settlement and system operation, two case studies are considered: (a) Base case (without HEFR); and (b) With HEFR. Three operational scenarios are designed for each case study: (a) Normal operation, (b) Uncertainties of wind and/or PV and (c) Congestion on line 19-20.

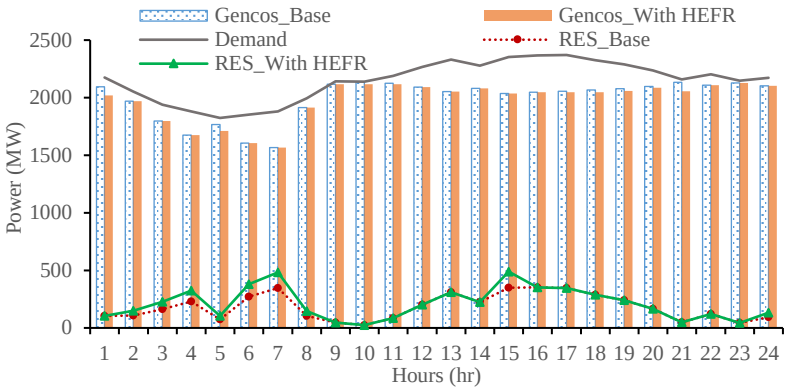


Figure 4.2: Market clearing for both cases, Normal operation

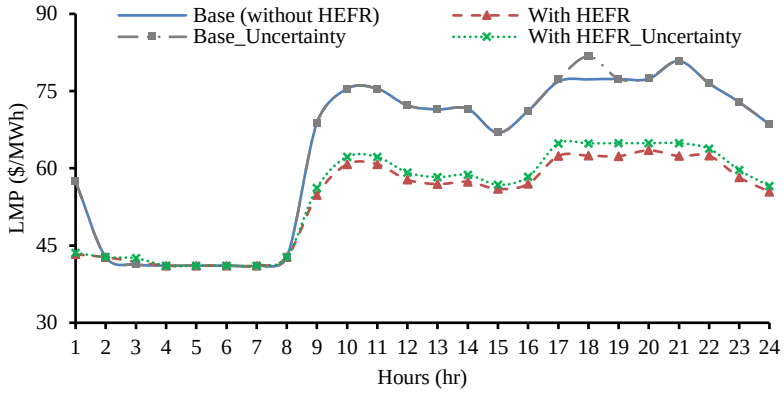


Figure 4.3: LMPs at bus-13, Normal and Uncertainties scenarios

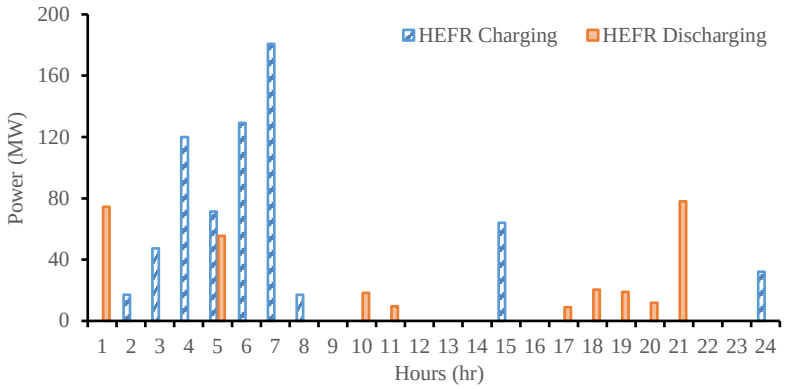


Figure 4.4: HEFRs charging/discharging profiles, Normal operation

4.5.1 Normal Operation Scenario

Fig. 4.2 presents the cleared demand, generation and RES profiles, while Fig. 4.3 presents the LMP profiles at bus-13 for both cases (without and with HEFRs) in Normal operation. It can be noted from Fig. 4.2 that the inclusion of HEFRs reduced RES curtailment, especially during hours (3-8, 15) and decreased gencos dispatch during peak hours (1, 17-21), as compared to Base case. It is observed that inclusion of HEFRs in the DAM resulted in lowering the LMPs, especially during high demand hours (9-14) and peak demand hours (1, 17-21) as compared to Base case when HEFRs were excluded. Fig. 4.4 presents the hourly dispatch of HEFR units in Normal operation; the PtH mode (electrolyzer producing hydrogen) is mainly during low demand hours (2-8 and 15) while the HtP mode (fuel cell generating electricity) occurs during peak hours (1, 17-21) and some in-between hours (5, 10, 11) to ensure the pressure in storage tanks are within limits. At the end of the market settlement period, charging operation takes place at hour-24 to reset the storage tanks moles content to its initial value, for the next day (4.8).

Table 4.1 presents a summary of DAM clearing for Normal operation, in both cases. It can be noted that the participation of HEFRs yielded higher social welfare as compared to Base case. Also, their inclusion in electricity markets resulted in lowering system emissions. Defining an *F-parameter* as the ratio (in %) of installed HEFR capacity to the total system capacity, the values obtained in the present studies [Table 4.1] corresponds to $F = 10\%$. The impact on market attributes will be more significant with entry of larger capacity HEFRs or when cheaper offer prices become viable.

Table 4.1: DAM Clearing (Aggregated over 24-hr)

	Normal Operation	
	Base Case (without HEFR)	***With HEFR***
Social Welfare ($)	3,760,391	3,767,253
Total Emissions (tonnes)	25,535	25,449
Demand Cleared (MWh)	51,570	51,570
Gencos Dispatch (MWh)	47,851	47,535
RES Dispatch (MWh)	4,343	5,039
HEFR Charging (MWh)	-	679
HEFR Discharging (MWh)	-	296

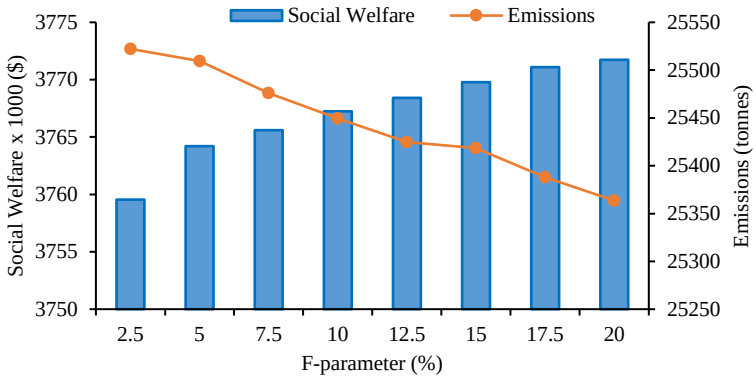


Figure 4.5: Effect of HEFRs installed capacity, Normal operation

Sensitivity Analysis

To examine the effect of increased installed capacity of HEFRs on the market attributes, a sensitivity analysis is carried out by varying the *F-parameter*. From Fig. 4.5 it is noted that the social welfare increased while the total system emissions decreased with increase in F, for Normal operation. Thus, the above-stated hypothesis proved to be true. It can be expected that similar effects will be observed when the HEFR operational cost reduces with the introduction of incentives from the utility or government, and with large-scale production of HEFRs, resulting in lower costs, and consideration of emission tax credits.

4.5.2 Uncertainties Scenario

This scenario examines the performance of the proposed model under uncertainties due to intermittency of RES, considering the wind and PV generations to be a fraction of that in the Normal operation. Table 4.2 summaries the DAM clearing results for both cases with different RES uncertainties. It is noted that the social welfare reduced in both cases, with the reduction being notably more without HEFRs (Base case), during lower wind and/or PV availability as compared to Normal operation since costlier resources are used to compensate for the variations. Further, a sub-scenario is considered wherein wind and PV varies only during peak hours (17-21), when they are at 85% of their Normal operation values. It is observed that (Fig. 4.3) there is an upward shift in LMP profiles at bus-13 for both cases (without and with HEFRs) in this sub-scenario; with a spike in Base case (without HEFRs) while a more flattened profile with inclusion of HEFRs.

Table 4.2: DAM with Uncertainties (Aggregated over 24-hr)

RES Uncertainties	**Base Case** *Social Welfare ($)*	**With HEFRs** *Social Welfare ($)*	*HEFR Charging/ Discharging (MWh)*
Normal	3,760,391	3,767,253	679 / 296
Wind, PV: 85%	3,743,154	3,754,042	761 / 332
Wind: 90%	3,750,749	3,759,926	656 / 286
Wind: 80%	3,740,895	3,752,629	812 / 354
Wind: 70%	3,730,742	3,744,779	923 / 412
PV: 90%	3,758,623	3,765,924	669 / 292
PV: 80%	3,756,848	3,764,502	623 / 271
PV: 70%	3,755,072	3,763,154	615 / 268

4.5.3 Congestion Scenario

This scenario examines the contribution of HEFRs to system operation, line congestion and electricity market prices. As load increases during high demand hours, the transmission line connecting buses 19 and 20 was congested in the direction from bus-20 to bus-19. Fig. 4.6 presents the LMP profiles at bus-19, for both cases (without/ with HEFRs), for Normal and Congestion scenarios. It is seen that the LMP profiles shifted upwards in

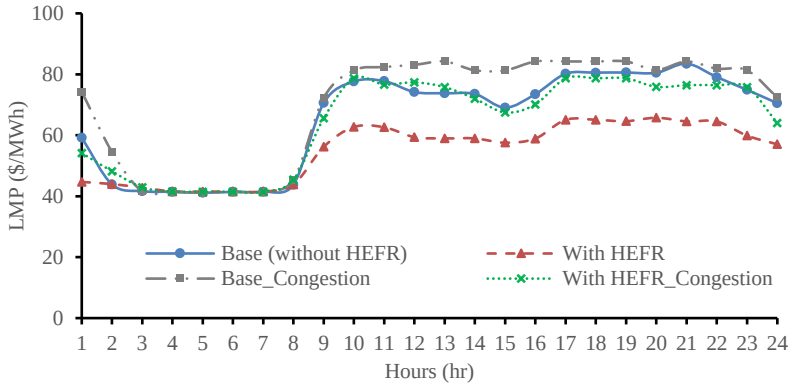


Figure 4.6: LMPs at bus-19 for Normal and Congestion scenarios

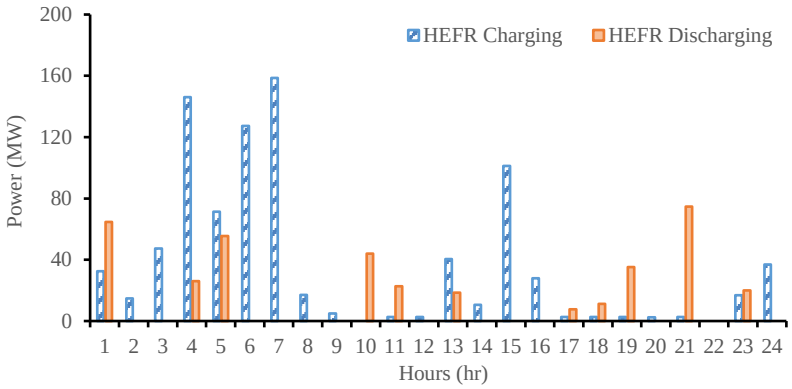


Figure 4.7: HEFRs charging/discharging, Congestion scenario

both cases with congestion, but with HEFRs, the shift was lower than that without. The HEFR charging and discharging profiles (Fig. 4.7) changed in the Congestion scenario as compared to Normal operation (Fig. 4.4). The LMPs increase with congestion because the load at bus-19, which was earlier fed through line 19-20, is now supplied through another line, resulting in increased generation from more expensive resources.

4.6 Summary

A generic framework and a comprehensive mathematical model of an HEFR-integrated, LMP-based, day-ahead electricity market were proposed. The model considered detailed physical, energy arbitrage and operational characteristics of the HEFRs. The developed model was tested on the IEEE 24-bus RTS with RES (PV and wind). To examine the performance of the model, two cases were considered: without and with HEFRs, for Normal, Uncertainties and Congestion scenarios. It was seen that the participation of HEFRs in the DAM yielded higher social welfare, reduced RES curtailment and resulted in lower system emissions. Their inclusion also resulted in lowering the LMP profiles in all three scenarios: normal operation, RES uncertainties and during line congestion. The outcomes of sensitivity analysis showed that social welfare increased and system emissions reduced with higher penetration of HEFRs. The main contents of this chapter have been published in [174]. Based on the studies carried out in this chapter, the proposed framework integrating GHSs/HEFRs impacts the electricity market in terms of computational efforts and other complexity challenges as any other ESSs which need operational and energy arbitrage characteristics to be considered. While scaling to more larger and complex power systems, the impact of these hydrogen-based resources participation might not be noticeable if they are not in comparable capacity. Furthermore, HEFRs can act as flexible resources (consisting load, storage and generation components) which can support system operations effectively.

Chapter 5

Design of Multi-Settlement Electricity Markets Considering Demand Response and Battery Energy Storage Systems Participation[1]

5.1 Nomenclature

Sets & Indices

i, k	Buses, $i \in I$.
e	BESS, $e \in E$.

[1]Parts of this chapter have been published in:

- A. Goyal and K. Bhattacharya, "Design of multi-settlement electricity markets considering demand response and battery energy storage systems participation," *IEEE Trans. on Energy Markets, Policy and Regulation*, (accepted 2024) available in IEEE XPlore Early Access.
- A. Goyal, K. Bhattacharya, and N. Padmanabhan, "LMP-based dayahead electricity market design considering the participation of DR and BESS," *Proc. IEEE Power & Energy Society General Meeting*, Denver, USA, July 2022.

j	Generators (Gen), $j \in J$.
q	Time (hour), $q \in Q$.
h	Blocks of consumer bids, $h \in N_{CB}$.
n	Blocks of Gen offers, $n \in N_{GO}$.
wg	Wind generation facility, $wg \in WG$.
pv	Solar (PV) facility, $pv \in PV$.
Ei	BESS connected to bus i.
Ji	Generators connected to bus i.
m	RTM settlement interval (min), $m \in M$.

Parameters

C^{D}	Demand bid price in DAM, \$/MWh.
$C^{G/GSR}$	Gen energy/SR offer price in DAM, \$/MWh, \$/MW.
$C^{SU/DN}$	Gen start-up/shut-down cost, \$.
C^{Wg}, C^{PV}	Wind/PV energy offer price in DAM, \$/MWh.
$C^{DRE/DRSR}$	DR offer price for energy/SR in DAM, \$/MWh, \$/MW.
$C^{ch/Dch}$	BESS charging/discharging bid/offer price in DAM, \$/MWh.
C^{BESR}	BESS SR offer price in DAM, \$/MWh.
a, b, c, d	BESS cost coefficients.
$\overline{SOC}, \underline{SOC}$	BESS SOC upper/lower limits, p.u.
C_{D}^{RT}	Demand bid price in RTM, \$/MWh.
C_{G}^{RT+}, C_{G}^{RT-}	Gen up/down service offer in RTM, \$/MWh.
C_{B}^{RT+}, C_{B}^{RT-}	End-point balancing up/downward services offer price in RTM, \$/MWh.
C_{DRE}^{RT}	DR offer price in RTM, \$/MWh.
$C_{ch/Dch}^{RT}$	BESS charging/discharging bid/offer price in RTM, \$/MWh.
RU, RD	Ramp up/down limits of Gen, MW/hour.
$\overline{P}_G$	Upper limit on real power generation, MW.
$\underline{P}_G$	Lower limit on real power generation, MW.

$\overline{P}_{DRE}^{RT}$	Maximum DR offer available in RTM, MW.
$\overline{P}_{ch/Dch}$	Maximum BESS charging/discharging power limits, MW.
P_G^{DA}	Generation cleared from Gen in DAM, MW.
P_{DRE}^{DA}	DR cleared in DAM, MW.
$P_{ch/Dch}^{DA}$	BESS charging/discharging power cleared in DAM, MW.
P_{GSR}^{DA}	SR cleared from Gen in DAM, MW.
P_{DRSR}^{DA}	SR cleared from DR in DAM, MW.
SOC^{DA}	DAM cleared BESS SOC in RTM, p.u
w^{DA}	1, if Gen cleared/committed for dispatch in DAM, 0 otherwise.
$BCap$	BESS energy capacity, MWh.
η	BESS round-trip efficiency, %.
B	Element of susceptance matrix, p.u.
$\overline{PFlow}$	Maximum transmission line capacity, MW.
$P_G^{DALF/RW}$	Gen day-ahead load-following ramp/rolling window power in RTM, MW.
$\overline{E}^{Dn/Up}$	Maximum BESS offer for down (charging)/up (discharging) services in RTM, MWh.
$\overline{E}_{ch/Dch}^{RT}$	Maximum BESS charging/discharging energy capacity in RTM, MWh.

Variables

P_{Wg}^{RT}	Wind generation in real-time, MW.
P_{PV}^{RT}	Solar (PV) generation in real-time, MW.
P^D	Demand cleared in DAM, MW.
$P^{G/GSR}$	Gen energy/SR offer cleared in DAM, MW.
$P^{Wg/PV}$	Wind/solar generation cleared in DAM, MW.
$P^{DRE/DRSR}$	Consumers' DR cleared for energy/SR in DAM, MW.
DCR	BESS discharge rate, p.u.
SOC^{DA}	BESS SOC in DAM, p.u.

SOC^{Dch}	BESS SOC after discharging in DAM, MWh.
$SOC^{SRC/SR}$	BESS capacity cleared for SR provision in DAM, MWh/p.u.
P_D^{RT}	Demand cleared in RTM, MW.
P_G^{RT}	Generation cleared from Gen in RTM, MW.
P_G^{RT+}, P_G^{RT-}	Up/down-balancing services from Gen in RTM, MW.
P_B^{RT+}, P_B^{RT-}	Up/down end-point balancing services in RTM, MW.
P_{DRE}^{RT}	DR cleared in RTM, MW.
$P_{ch/Dch}^{RT}$	Down/up power from BESS in RTM, MW.
$E_{ch/Dch}^{RT}$	Down/up energy from BESS in RTM, MWh.
P_{loss}^{RT}	Power loss in the line in RTM, MW.
δ	Voltage angle, radian.
SOC^{RT}	BESS SOC in RTM, p.u.
X^{RT}	1, if DR cleared in RTM, 0 otherwise.
Y^{RT+}, Y^{RT-}	1, if Gen up/down-balancing services cleared in RTM, 0 otherwise.
$Z1^{RT}, Z2^{RT}$	1, if BESS providing down/up services in RTM, 0 otherwise.

5.2 Introduction

This chapter presents a generic framework and detailed mathematical models for LMP-based, loss included, multi-settlement wholesale electricity markets for 24-hour ahead scheduling and 5-min ahead dispatch, considering simultaneous participation of DR and BESSs, incorporating consumers' bid/ DR offer structures and BESS cost models based on DOD and DCR. The proposed new ramping constraints for generators taking into account the contribution of resulting 5-min ramp availability from the cleared DAM generators schedules of each hour while settling of the RTM is also presented. Different case studies are demonstrated to examine the impact of DR and BESS participation on MSM settlements and effect of inclusion of new ramping constraints. The MSM model behaviour under events such as load deviations, RES forecast errors and outages are also presented.

5.3 DR-BESS Integrated MSM Framework

A novel, coordinated, two-stage framework, integrating DR and BESS, is developed wherein the Stage-1 is optimized for DAM settlement and Stage-2 for RTM settlement (Fig. 5.1), based on the SMD structure of FERC. The flow of information from DAM to RTM remains the conventional way, as followed for MSM by the ISOs. Stage-1 presents a generic electricity market framework to simultaneously integrate DR and BESS in an LMP-based co-optimized day-ahead energy and SR market. Further, Stage-2 presents a new approach of integrating DR and BESS in RTM for energy-balancing. The proposed model takes into account FERC Order 745 and Order 841, consumers' preferences, DR capacity offered as fraction of cleared demand, BESS cost functions based on their DOD and discharge rates, priority dispatch of RES and other operational aspects of various market participants. Additionally, a novel constraint is proposed to incorporate the day-ahead load-following ramp schedules of generators in settling the RTM. The term proposed to depict these ramp schedules of generators is DALF Ramp. Detailed studies are carried out by simulating various scenarios to analyze the impact of DALF Ramp and DR & BESS simultaneous integration in the MSM (DAM and RTM) on LMPs, line congestions, line flows, outages, dispatch and other techno-economical indicators, by testing the proposed model on modified IEEE 24-bus RTS [160] which includes RES.

Market settlement is carried out, once market participants submit their respective bids and/or offers in the respective markets, by solving a MIP optimization model. Fig. 5.1 describes the proposed framework of the novel LMP-based MSM (coordinated DAM+RTM) model including RES, DR and BESS. The outputs of the proposed framework comprises UC decisions, DALF Ramp, day-ahead dispatch schedules, power flows, line congestions, and LMPs for energy and SR in DAM. And real-time dispatch schedule, power flows, line congestions and LMPs for energy in RTM.

5.4 Mathematical Models of Proposed DR-BESS Integrated Multi-Settlement Electricity Market

5.4.1 Bid/Offer Structures

In this work, the consumers (large industrial and commercial loads) submit their DR offers for energy and SR provisions in price-quantity pairs in the DAM and for energy-balancing

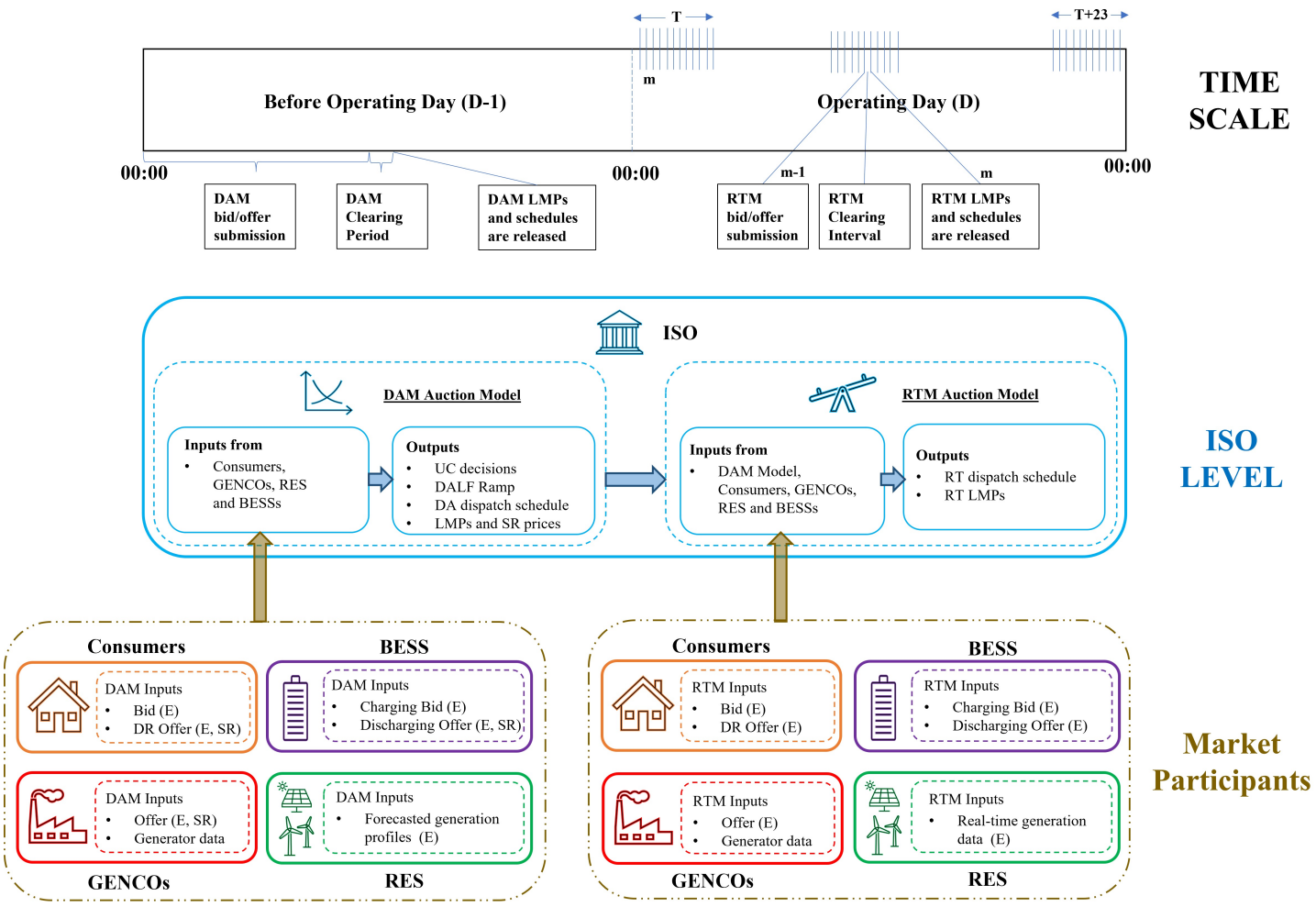


Figure 5.1: DR-BESS integrated MSM (coordinated DAM and RTM) framework.

in the RTM (FERC Order 745). The percentage of DR quantity offered by a consumer for energy and SR provisions is controlled by respective γ-factors in different markets [69].

Grid-connected, independently-owned BESSs are considered, to submit bids/offers to the ISO for energy and/or SR, in DAM and/or RTM (FERC Order 841). In the energy-SR co-optimized DAM, BESSs are considered to participate in three ways: (a) bid to buy energy for charging, (b) offer to sell energy by discharging and (c) offer to provide SR provisions. While in the energy-balancing RTM, the BESS partakes in two ways: (a) bid to buy energy for charging and (b) offer to sell energy by discharging. There are β-parameters associated with charging, discharging and SR capabilities of BESSs in order to provide flexibility to BESS owners participating in different markets [35].

The gencos submit their offers for energy and SR provisions in the DAM in price-quantity pairs. They also submit start-up and shut-down price offers associated with each generator type. In the RTM, the gencos submit energy offers only, similar to the DAM *i.e.* in price-quantity pairs with/without alterations.

5.4.2 DAM Model

The DAM model was presented in detail by the authors in [35,69,175]; the objective function is reproduced below for sake of continuity along with the list of some key constraints.

Objective Function

To maximize the social welfare, given as follows:

$$J = \underbrace{\sum_{q\epsilon Q}\sum_{h\epsilon N_{CB}}\sum_{i\epsilon I}(C^{D}_{i,h,q}P^{D}_{i,h,q})}_{\text{(Consumers' Gross Surplus)}} + \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(C^{ch}_{e,q}E^{ch}_{e,q})}_{\text{(BESSs' Charging Surplus)}}$$
$$- \underbrace{\sum_{q\epsilon Q}\sum_{wg\epsilon WG}(C^{Wg}_{wg,q}P^{Wg}_{wg,q}) - \sum_{q\epsilon Q}\sum_{pv\epsilon PV}(C^{PV}_{pv,q}P^{PV}_{pv,q})}_{\text{(Energy Supply Costs from RES (Wind and Solar))}} - \underbrace{\sum_{q\epsilon Q}\sum_{j\epsilon J}\sum_{n\epsilon N_{GO}}(C^{G}_{n,j,q}P^{G}_{n,j,q} + C^{GSR}_{n,j,q}P^{GSR}_{n,j,q})}_{\text{(Gencos' Energy and SR Supply Costs)}}$$
$$- \underbrace{\sum_{q\epsilon Q}\sum_{j\epsilon J}(C^{SU}_{j,q}U_{j,q} + C^{DN}_{j,q}V_{j,q})}_{\text{(Gencos' Start-up and Shut-down Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{h\epsilon N_{CB}}\sum_{i\epsilon I}(C^{DRE}_{i,h,q}P^{DRE}_{i,h,q} + C^{DRSR}_{i,h,q}P^{DRSR}_{i,h,q})}_{\text{(DR Energy and SR Provision Costs)}}$$
$$- \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(a_e SOC^{Dch}_{e,q} + b_e SOC^{Dch}_{e,q-1} + c_e DCR_{e,q} + d_e)}_{\text{(BESSs' Discharging Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(C^{BESR}_{e,q}SOC^{SRC}_{e,q})}_{\text{(BESS SR Provision Costs)}} \quad (5.1)$$

The first term in (5.1) represents the gross surplus of consumers and the second term shows BESS charging cost. The third and fourth terms denote the total cost of energy supply from RES. The fifth term represents the operational cost of generators including energy and SR provisions. The start-up and shut-down cost of generators are given in the sixth term. The seventh term denotes the cost for DR provisions in energy and SR markets, respectively. The discharging cost of BESS, accounting for its degradation, modelled based on the DOD and discharge rate, is given by the eighth term [35]. The last term denotes the cost of SR provision by BESS. The objective function is subjected to a set of constraints; of which some key constraints are given below; while the complete model is presented in [35, 69, 175]:

- *Day-Ahead Demand-Supply Balance:* This constraint maintains the balance between demand and supply at each hour at a bus. It is formulated using dc load flow equations and takes into account the line losses [120].

$$\sum_{j\epsilon J_i}P^{G}_{j,q} + \sum_{wg\epsilon WG_i}P^{Wg}_{wg,q} + \sum_{pv\epsilon PV_i}P^{PV}_{pv,q} + P^{DRE}_{i,q} + \sum_{e\epsilon E_i}P^{Dch}_{e,q} - \sum_{e\epsilon E_i}P^{ch}_{e,q} - P^{D}_{i,q}$$
$$= \sum_{k\epsilon I}(0.5P^{loss}_{i,k} + B_{i,k}(\delta_{i,q} - \delta_{k,q})) \quad (5.2)$$

- *Day-Ahead DR Constraints:* These constraints ensure that the DR capacity allocated to consumers for energy and SR markets is a fraction of their total cleared demand.
- *Day-Ahead BESS Energy and SR Constraints:* These constraints ensure that the charge/discharge schedules and the SR cleared in the DAM are limited by their respective maximum bid/offer quantities. The end-point SOC constraint ensures that the SOC at the end of each day is not lower than the specified initial SOC for the next day. The following operational constraints determine the SOC at any hour, based on charging or discharging operation:
  For $q = 1$:

$$(SOC^{DA}_{e,q} - SOC^{DA}_{e,'0'})BCap_e = P^{DA}_{ch_{e,q}}\eta_e - P^{DA}_{Dch_{e,q}}/\eta_e \quad \forall e \,\epsilon\, E \tag{5.3}$$

  For $q > 1$:

$$(SOC^{DA}_{e,q} - SOC^{DA}_{e,q-1})BCap_e = P^{DA}_{ch_{e,q}}\eta_e - P^{DA}_{Dch_{e,q}}/\eta_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.4}$$

  End-point SOC Constraint:

$$SOC^{DA}_{e,'0'} \leq SOC^{DA}_{e,'24'} \qquad \forall e \,\epsilon\, E \tag{5.5}$$

  where $SOC^{DA}_{e,'0'}$ represents the initial SOC of a BESS unit at the start of the day.
  SOC Limits:

$$\underline{SOC}_e + SOC^{DA}_{SR_{e,q}} \leq SOC^{DA}_{e,q} \leq \overline{SOC}_e \qquad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.6}$$

- *Day-Ahead Market Clearing Constraints:* These constraints ensure that the cleared demand of consumers, the supply of generators, DR provisions and the charging/discharging of BESS are within their maximum bid/offer quantities.
- *Day-Ahead Other Constraints:* These constraints include UC requirements such as ramp-rate limits, minimum up-time/down-time constraints, and coordination constraints. Furthermore, the coordination constraints for BESS and DR prevent simultaneous discharging and charging operations of a BESS unit and ensure that cleared DR blocks are aligned with the cleared demand bid blocks.

5.4.3 RTM Model

The RTM model presented below is a novel contribution of this work which includes the simultaneous participation of DR and BESS, newly formulated DALF Ramp constraints and other associated operational constraints based on the settlement of DAM complying with FERC's SMD structure.

Objective Function

To maximize the social welfare in the considered interval of 5-min, given as follows:

$$J = \underbrace{\sum_{i\epsilon I}\sum_{h\epsilon N_{CB}}\left(C^{RT}_{D_{i,h,q,m}}(P^{RT}_{D_{i,h,q,m}} - P^{DA}_{D_{i,h,q}})\right)}_{\text{(Consumers' Surplus in RTM)}} + \underbrace{\sum_{j\epsilon J}\sum_{n\epsilon N_{GO}}(C^{RT-}_{G_{n,j,q,m}}P^{RT-}_{G_{n,j,q,m}})}_{\text{(Gencos' Downward Balance)}}$$
$$+ \underbrace{\sum_{e\epsilon E}(C^{RT}_{ch_{e,q,m}}E^{RT}_{ch_{e,q,m}})}_{\text{(BESSs' Charging Costs)}} - \underbrace{\sum_{i\epsilon I}\sum_{h\epsilon N_{CB}}(C^{RT}_{DRE_{i,h,q,m}}P^{RT}_{DRE_{i,h,q,m}})}_{\text{(DR Provision in RTM)}} - \underbrace{\sum_{j\epsilon J}\sum_{n\epsilon N_{GO}}(C^{RT+}_{G_{n,j,q,m}}P^{RT+}_{G_{n,j,q,m}})}_{\text{(Gencos' Upward Balance)}}$$
$$- \underbrace{\sum_{e\epsilon E}(C^{RT}_{Dch_{e,q,m}}E^{RT}_{Dch_{e,q,m}})}_{\text{(BESSs' Discharging Costs)}} + \underbrace{\sum_{i\epsilon I}(C^{RT-}_{B_{i,q,m}}P^{RT-}_{B_{i,q,m}}) - \sum_{i\epsilon I}(C^{RT+}_{B_{i,q,m}}P^{RT+}_{B_{i,q,m}})}_{\text{(Balancing Downward and Upward Services)}} \quad (5.7)$$

The first term in (5.7) represents the consumers' surplus based on real-time demand variations vis-a-vis the DAM cleared demand. The operational cost of generators providing downward and upward balance in the real-time energy market are represented by the second and fifth terms, respectively. Note that the second term (downward balance) denotes generation reduction in real-time from its DAM schedule, which appears as a surplus, while the fifth term (upward balance) denotes generation increase and the associated cost over and above the DAM dispatch. The third and sixth terms denotes BESS charging and discharging costs, respectively, while the fourth term represents the cost for DR provisions in the real-time energy market. The seventh and eighth terms denote the surplus and cost, respectively, associated with end-point balancing services. The objective function in (5.7) is subjected to the following constraints.

Real-Time Demand-Supply Balance

This constraint ensures the bus-wise energy balance between demand and supply at each 5-min RTM settlement interval *(m)*, formulated using dc load flow equations, wherein the

line losses are included using a linearized technique presented in [120].

$$\sum_{j\epsilon J_i}(P^{DA}_{G_{j,q}}+P^{RT+}_{G_{j,q,m}}-P^{RT-}_{G_{j,q,m}}+P^{RT}_{G_{j,q,m-1}})+(\sum_{wg\epsilon WG_i}P^{RT}_{Wg_{wg,q,m}}+\sum_{pv\epsilon PV_i}P^{RT}_{PV_{pv,q,m}})-P^{RT}_{D_{i,q,m}}-P^{RT-}_{B_{i,q,m}}$$
$$+P^{RT+}_{B_{i,q,m}}+(P^{DA}_{DRE_{i,q}}+P^{RT}_{DRE_{i,q,m}})+\sum_{e\epsilon E_i}\Big((P^{DA}_{Dch_{e,q}}+P^{RT}_{Dch_{e,q,m}})-(P^{DA}_{ch_{e,q}}+P^{RT}_{ch_{e,q,m}})\Big)$$
$$=\sum_{k\epsilon I}\Big(0.5P^{RT}_{loss_{i,k,q,m}}+B_{i,k}(\delta^{RT}_{i,q,m}-\delta^{RT}_{k,q,m})\Big) \quad (5.8)$$

where

$$P^{RT}_{G_{j,q,m}}=P^{DALF}_{G_{j,q}}+P^{RT+}_{G_{j,q,m}}-P^{RT-}_{G_{j,q,m}}+P^{RT}_{G_{j,q,m-1}} \qquad \forall j\,\epsilon\,J,\ \forall m\,\epsilon\,M \quad (5.9)$$

Note that in (5.8), P^{RT-}_{B} and P^{RT+}_{B}, represent the end-point balancing services cleared in the RTM; these are typically offered by curtailable loads, operating reserve provisions, *etc*, and are cleared only when other resources are unable to meet the requirements. Their selection is based on their submitted bid/offer prices.

New Ramping Constraints for Generators Considering DALF Ramp

These constraints ensure that the ramp-up/down limits of a generator at any RTM interval are not violated, taking into consideration the ramping schedules put in place by the DAM clearing decisions.

For $P^{DALF}_{G_{j,q}} \geq 0$:

$$P^{DALF}_{G_{j,q}}+P^{RT+}_{G_{j,q,m}}\leq RU_j/M \qquad \forall j\,\epsilon\,J,\ \forall m\,\epsilon\,M \quad (5.10)$$
$$P^{RT-}_{G_{j,q,m}}\leq RD_j/M \qquad \forall j\,\epsilon\,J,\ \forall m\,\epsilon\,M \quad (5.11)$$

For $P^{DALF}_{G_{j,q}} < 0$:

$$P^{RT+}_{G_{j,q,m}}\leq RU_j/M \qquad \forall j\,\epsilon\,J,\ \forall m\,\epsilon\,M \quad (5.12)$$
$$-P^{DALF}_{G_{j,q}}+P^{RT-}_{G_{j,q,m}}\leq RD_j/M \qquad \forall j\,\epsilon\,J,\ \forall m\,\epsilon\,M \quad (5.13)$$

where

$$P^{DALF}_{G_{j,q}}=(P^{DA}_{G_{j,q+1}}-P^{DA}_{G_{j,q}})/M \qquad \forall j\,\epsilon\,J \quad (5.14)$$

Note that the term, P^{DALF}_{G}, represents the ramp requirement for a generator cleared in the 5-min RTM interval based on its DAM schedule. The P^{DALF}_{G} can take positive

(ramp up), zero (no ramp), or negative (ramp down) values, depending on the difference between the consecutive hour DAM schedules, $P_{G_q}^{DA}$ and $P_{G_{q+1}}^{DA}$. Equations (5.10) and (5.11) hold true when P_G^{DALF} is either positive or zero; note that only the ramp-up constraint of the generator is impacted with the addition of the DALF Ramp (P_G^{DALF}) term, while the ramp-down constraint remains in its conventional form. In complementary, when P_G^{DALF} is negative, (5.12) and (5.13) denotes the ramping constraints for generators. Herein, the ramp-up constraint remains in its conventional form while the ramp-down constraint is affected by the inclusion of the DALF Ramp (P_G^{DALF}) term.

To the best of the author's knowledge, such ramping of generation units, obtained from their DAM schedules, are generally neglected when modeling the RTM settlement, by assuming it to be taken care of by operating reserves. Hence, existing models neglect the potential of utilizing the ramp up/down schedules for compensating real-time fluctuations in demand-supply balance. Moreover, note that if the ramp schedules were not considered, the model accuracy would be compromised. To this effect, the novel concept of incorporating the DALF Ramp schedules in settling the RTM are presented to provide realistic dispatch of generators in real-time.

From a comprehensive review of electricity markets worldwide, it is noted that DAMs are typically settled on an hourly basis, while most RTMs are settled 5-minute ahead, with a few 15-minute or 1-min ahead settlements, refer Table 5.1 [126]. It is envisaged that the proposed DALF Ramp will serve as an effective tool for accurate dispatch in RTMs as long as the DAM settlement time interval is different from RTM intervals. For instance, if the DAM were to be a five-minute market in the future, then presumably, the corresponding RTM settlement would be 1-minute ahead, and the proposed DALF Ramp will still work.

Table 5.1: RTM Settlement Intervals Practiced by Different System Operators [126]

Independent System Operators (ISOs)								
ISO-NE	PJM	SPP	MISO	NYISO	CAISO	ERCOT	IESO	AESO
5-min	5-min	5-min	5-min	5-min	5-min, 15-min	15-min	5-min	1-min

Rolling Window Constraints for Generators

These constraints ensure that real-time dispatch of generators in a 5-min interval is determined based on their ramping limits, previous all 5-min interval dispatches and ramping

capability available in the remaining 5-min intervals of the hour.

For $P^{RW}_{G_{j,q,m-1}} \geq 0$ and $m < 12$:

$$P^{RT+}_{G_{j,q,m}} + P^{RW}_{G_{j,q,m-1}} \leq (M-m)RU_j/M \quad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.15}$$

$$P^{RT-}_{G_{j,q,m}} - P^{RW}_{G_{j,q,m-1}} \leq (M-m)RD_j/M \quad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.16}$$

For $P^{RW}_{G_{j,q,m-1}} \leq 0$ and $m < 12$:

$$P^{RT+}_{G_{j,q,m}} - P^{RW}_{G_{j,q,m-1}} \leq (M-m)RU_j/M \quad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.17}$$

$$P^{RT-}_{G_{j,q,m}} + P^{RW}_{G_{j,q,m-1}} \leq (M-m)RD_j/M \quad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.18}$$

where

$$P^{RW}_{G_{j,q,m}} = P^{RW}_{G_{j,q,m-1}} + P^{RT+}_{G_{j,q,m}} - P^{RT-}_{G_{j,q,m}} \quad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.19}$$

Note that the term, P^{RW}_{G}, represents the dispatched power of generators in rolling window, obtained as the sum of the current 5-min interval dispatch and all previous 5-min real-time dispatches in an hour. It can take positive, zero or negative values, depending on the dispatches, as per (5.19). Equations (5.15) and (5.16) hold true when P^{RW}_{G} is either positive or zero; whereas, in complementary, (5.17) and (5.18) are active when P^{RW}_{G} is negative or zero. In the case when P^{RW}_{G} is zero, (5.15) & (5.16) and (5.17) & (5.18) becomes identical. These constraints ensure that within an hour, each 5-min interval dispatch in the RTM are cleared such that none of the subsequent intervals ramp limits or DAM schedules of generators are violated. The proposed model considering novel constraints, as presented in this section, comprehensively captures the dispatch of subsequent intervals within an hour, taking into account DAM settlement results, in a MSM framework; which were neglected in most of the reported RTM models.

Real-Time DR Constraints

These constraints ensure that the DR cleared in the RTM, over and above that cleared in the DAM, are a fraction of the real-time cleared demand.

$$P^{RT}_{DRE_{i,q,m}} \leq (\gamma^{RT}_{i,q,m}(P^{RT}_{D_{i,q,m}}) - P^{DA}_{DRE_{i,q}} - P^{DA}_{DRSR_{i,q}}) \quad \forall i \,\epsilon\, I,\ \forall m \,\epsilon\, M \tag{5.20}$$

where γ^{RT} is a parameter chosen by the participating consumer and denotes the share of cleared demand that the consumer is willing to offer as DR. The other two terms on the right-hand side of (5.20), $P^{DA}_{DRE_{i,q}}$ and $P^{DA}_{DRSR_{i,q}}$, denote the DR amount cleared in the DAM for energy and SR services, respectively at hour 'q' at bus 'i'.

Real-Time BESS Operational Constraints

During the RTM settlement of first interval *(m=1)* in any hour, the SOC is obtained from the DAM scheduled SOC for that hour (SOC_q^{DA}) and charging/discharging operation in that interval, as given as follows:
For $m = 1$:

$$(SOC^{RT}_{e,q,'1'} - SOC^{DA}_{e,q})BCap_e = (P^{RT}_{ch_{e,q,'1'}}\eta_e - P^{RT}_{Dch_{e,q,'1'}}/\eta_e)/M \quad \forall e \,\epsilon\, E \tag{5.21}$$

For $m > 1$:

$$(SOC^{RT}_{e,q,m} - SOC^{RT}_{e,q,m-1})BCap_e = (P^{RT}_{ch_{e,q,m}}\eta_e - P^{RT}_{Dch_{e,q,m}}/\eta_e)/M \quad \forall e \,\epsilon\, E \tag{5.22}$$

The real-time SOC of a BESS at any RTM interval (5.22) is determined from the SOC in the previous interval and the charging/discharging energy dispatched in this interval.

$$\underline{SOC}_e + SOC^{DA}_{SR_{e,q}} \leq SOC^{RT}_{e,q,m} \leq \overline{SOC}_e \quad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.23}$$

Equation (5.23) defines the upper and lower limits on the SOC in real-time (SOC^{RT}). The lower limit on SOC^{RT} is governed by the BESS minimum SOC, after subtracting the SOC allocated from the DAM for SR services (SOC^{DA}_{SR}). Note that the SOC assigned for SR is determined in the DAM and is an input into the RTM. The upper limit on SOC is governed by the maximum SOC which is typically equal or less than the BESS unit's energy capacity limit.

Real-Time BESS Energy Arbitrage Constraints

The cleared energy during charging and discharging operation of a BESS in real-time are given as follows:

$$E^{RT}_{ch_{e,q,m}} = (P^{RT}_{ch_{e,q,m}}\eta_e)/M \quad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.24}$$

$$E^{RT}_{Dch_{e,q,m}} = (P^{RT}_{Dch_{e,q,m}}/\eta_e)/M \quad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.25}$$

The maximum bid/offer by a BESS for downward balance services (*i.e.* charging)/upward balance services (*i.e.* discharging) in the RTM are based on its scheduled day-ahead SOC for that hour, reserved SR capacity and its capacity limits.

$$\overline{E}^{Dn}_{e,q} = (\overline{SOC}_e - SOC^{DA}_{e,q})BCap_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.26}$$

$$\overline{E}^{RT}_{ch_{e,q}} = \beta^{RT}_{ch_{e,q}} \overline{E}^{Dn}_{e,q} \qquad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.27}$$

$$\overline{E}^{Up}_{e,q} = (SOC^{DA}_{e,q} - SOC^{DA}_{SR_{e,q}} - \underline{SOC}_e) BCap_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.28}$$

$$\overline{E}^{RT}_{Dch_{e,q}} = \beta^{RT}_{Dch_{e,q}} \overline{E}^{Up}_{e,q} \qquad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{5.29}$$

Note that β^{RT}_{ch} and β^{RT}_{Dch} are BESS parameters denoting their level of participation as fraction of their available capacity in charging/discharging services in the RTM.

Real-Time Market Clearing Constraints

The following constraints ensure that the cleared quantities of gencos' offers, DR offers and BESS charging/discharging bids/offers are within their respective maximum quantities.

$$P^{RT+}_{G_{j,q,m}} \leq (\overline{P}_{G_{j,q}} - P^{DA}_{G_{j,q}} - P^{DA}_{GSR_{j,q}} - P^{RT}_{G_{j,q,m-1}}) Y^{RT+}_{j,q,m} \qquad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.30}$$

$$P^{RT-}_{G_{j,q,m}} \leq (P^{DA}_{G_{j,q}} + P^{RT}_{G_{j,q,m-1}} - \underline{P}_{G_{j,q}}) Y^{RT-}_{j,q,m} \qquad \forall j \,\epsilon\, J,\ \forall m \,\epsilon\, M \tag{5.31}$$

The upper limit on the upward and downward balancing services offered by generators in the RTM are given by (5.30) and (5.31), respectively. It can be noted that the capacity available for upward balancing services by a generator is governed by the generation maximum capacity ($\overline{P}_G$) net of the DAM generation allocated for energy (P^{DA}_G) and SR services (P^{DA}_{GSR}), and aggregation of all previous real-time 5-min interval dispatches in an hour ($P^{RT}_{G_{m-1}}$). The available quantity for downward balancing service is determined by the generation cleared in the DAM for energy (P^{DA}_G), aggregation of all previous real-time 5-min interval dispatches in an hour ($P^{RT}_{G_{m-1}}$) and generator minimum limit ($\underline{P}_G$).

$$P^{RT}_{DRE_{i,q,m}} \leq \overline{P}^{RT}_{DRE_{i,q}} X^{RT}_{i,q,m} \qquad \forall i \,\epsilon\, I,\ \forall m \,\epsilon\, M \tag{5.32}$$

Constraints (5.32) ensure that the DR services cleared in the RTM are within their maximum limits. While, the following constraints secure that the cleared quantities of BESS energy and power during charging/discharging operation are within their maximum bid/offer quantities:

$$E^{RT}_{ch_{e,q,m}} \leq \overline{E}^{RT}_{ch_{e,q}} Z1^{RT}_{e,q,m} \qquad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.33}$$

$$E^{RT}_{Dch_{e,q,m}} \leq \overline{E}^{RT}_{Dch_{e,q}} Z2^{RT}_{e,q,m} \qquad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.34}$$

$$P^{RT}_{ch_{e,q,m}} \leq \overline{P}_{ch_e} Z1^{RT}_{e,q,m} \qquad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.35}$$

$$P^{RT}_{Dch_{e,q,m}} \leq \overline{P}_{Dch_e} Z2^{RT}_{e,q,m} \qquad \forall e \,\epsilon\, E,\ \forall m \,\epsilon\, M \tag{5.36}$$

Real-Time Coordination Constraints

The following constraints ensure that a generator can provide its balancing services (up/down) in RTM, only if it was committed for that hour in DAM dispatch.

$$Y^{RT+}_{j,q,m} \leq w^{DA}_{j,q}, Y^{RT-}_{j,q,m} \leq w^{DA}_{j,q} \qquad \forall j \epsilon J, \forall m \epsilon M \tag{5.37}$$

$$Y^{RT+}_{j,q,m} + Y^{RT-}_{j,q,m} \leq 1 \qquad \forall j \epsilon J, \forall m \epsilon M \tag{5.38}$$

$$Z1^{RT}_{e,q,m} + Z2^{RT}_{e,q,m} \leq 1 \qquad \forall e \epsilon E, \forall m \epsilon M \tag{5.39}$$

$$X^{RT}_{i,q,m} \leq X^{DA}_{i,'1',q} \qquad \forall i \epsilon I, \forall m \epsilon M \tag{5.40}$$

Equation (5.38) ensures that a generator cannot simultaneously offer balance-up/balance-down services, while simultaneous charging/discharging operation of a BESS is prevented by (5.39). The constraint (5.40) ensures that only those consumers cleared in DAM are able to provide DR services in RTM.

Real-Time Endpoint Constraints

These include the endpoint constraints applied to BESSs and generation units at the last 5-min interval of an hour. They ensure that at the beginning of the next hour, the SOC levels of the BESSs/generators' dispatches are based on their DAM schedules for that hour.

$$SOC^{RT}_{e,q,'12'} \geq SOC^{DA}_{e,q} \tag{5.41}$$

$$P^{RT+}_{G_{j,q,'12'}} - P^{RT-}_{G_{j,q,'12'}} + P^{RT}_{G_{j,q,'11'}} = P^{DA}_{G_{j,q+1}} - P^{DA}_{G_{j,q}} \tag{5.42}$$

Transmission Line Limits

These constraints ensure that the line flows are within their line capacity limits.

$$B_{i,k}(\delta^{RT}_{i,q,m} - \delta^{RT}_{k,q,m}) \leq \overline{PFlow}_{i,k} \qquad \forall i,k \epsilon I, \forall m \epsilon M \tag{5.43}$$

5.5 Results and Discussions

The proposed models including DR and BESS were tested on the IEEE 24-bus RTS [160, 161], with wind and solar PV facilities additionally included at various buses. There are 3x100 MW wind generation and 3x100 MW solar generation provisions, located at six different buses. The three facilities of solar and those of wind are considered to be identical in their generation profiles [176, 177] for the sake of simplicity and without any loss of generality. The uncertainties in RES generation were simulated by considering their real-time generation to deviate from their DAM forecasted profiles by 5-25% (in steps of 5%) in either directions. To further examine the impact of RES uncertainties on the model performance and robustness, a Monte Carlo Simulation is carried out, and will be discussed in a latter subsection. The generator offers, demand bids and consumers' DR offers for energy and SR markets are in three price-quantity pairs [69]. The system also includes 10 BESS units of different capacities and initial SOCs, and are located at various buses as presented in [35]. The data considered for performing the case studies in this chapter are given in Appendices A, B and C.

The proposed LMP-based MSM (coordinated DAM and RTM) models are formulated as MIP problems in the GAMS environment [162] and solved using the CPLEX solver. To perform the objectives of this work (as mentioned in Section 1.3), the following cases studies and scenarios are designed. Detailed sensitivity analyses are carried out to examine the impact of DR and BESS attributes, and inclusion of DALF Ramp on market settlements.

5.5.1 Development of Case Studies and Scenarios

Case studies and scenarios considered for DAM are described in Table 5.2. For brevity, the results corresponding to the individual participation of DR and BESS in a DAM are not presented here. The authors have comprehensively examined the effect of simultaneous participation of DR and BESS over individual (one at a time) in a DAM in [175].

For RTM studies, the DAM outputs for Case-3, Scenario-1 (Normal operation considering DR and BESS) are used. Table 5.3 presents the case studies and scenarios considered for RTM. In order to examine the performance of the RTM model proposed in Section 5.4.3, three different 'instances' of demand variations are considered by deviating the demand at bus-13 and bus-15 from DAM cleared demand in the ways as described in Table 5.4. Fig. 5.2 illustrates the load variation profiles considered in the RTM for Hour-5 and Hour-17 for Instance-3.

Table 5.2: Case Studies and Scenarios for DAM

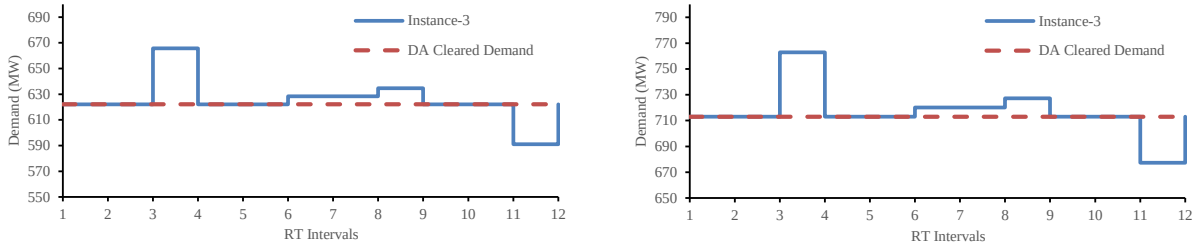
Cases		
Case-1	***Case-2***	***Case-3***
Base case (No DR or BESS)	DR & BESS in energy market only	DR & BESS in both energy and SR markets
Scenarios		
Scenario-1	***Scenario-2a***	***Scenario-2b***
Normal operation (no outages or congestion)	Outage of Gen-23 at bus-21 during peak hours (17-20)	Outage of line connecting 12-13 during peak hours (17-20)

Table 5.3: Case Studies and Scenarios for RTM

Cases			
Case-1	***Case-2***	***Case-3***	***Case-4***
Base case (No DR or BESS in RTM)	Only DR in RTM	Only BESS in RTM	DR & BESS both in RTM
Scenarios			
Scenario-1	***Scenario-2a***		***Scenario-2b***
Normal operation (no outages or congestion)	Outage of Gen-16 at bus-15 during sub-intervals 7-12 in an hour		Outage of line connecting bus 2-4 for an hour

Table 5.4: Instances for RTM

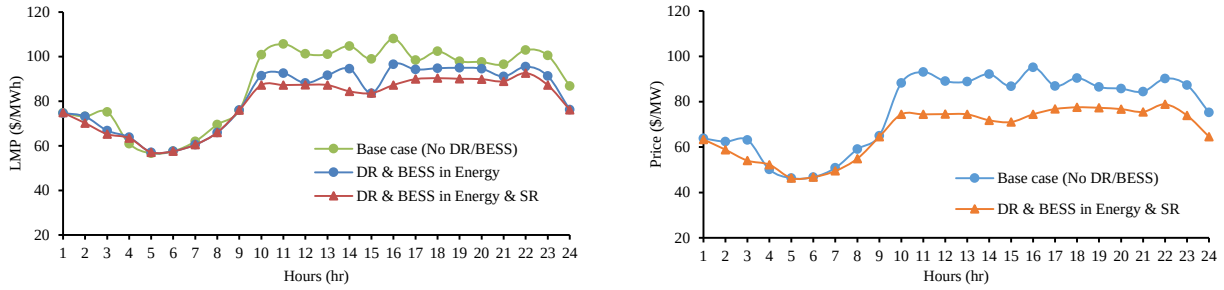
	Instances		
Sub-Intervals	***Instance-1***	***Instance-2***	***Instance-3***
3	7% increment	7% decrement	7% increment
6-7	1% increment	1% decrement	1% increment
8	2% increment	2% decrement	2% increment
11	5% increment	5% decrement	5% decrement



(a) Hour-5 (b) Hour-17

Figure 5.2: Instance-3 of demand variations in RTM

5.5.2 Analysis: DAM Horizon

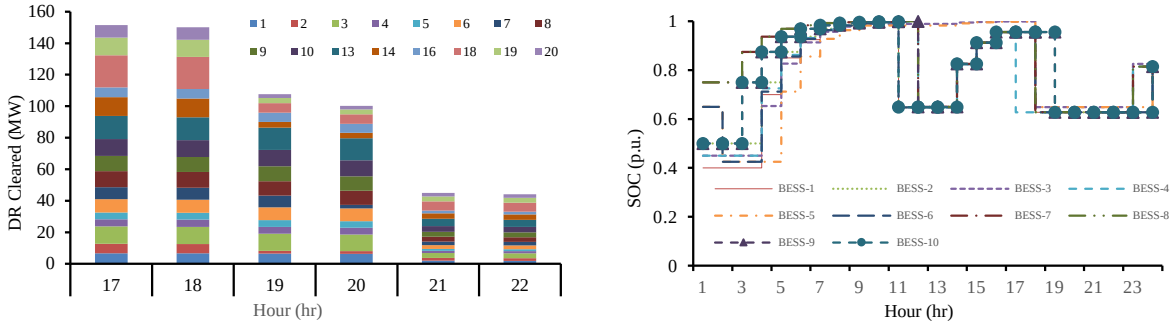


(a) LMP at bus-12 (b) Hourly SR prices

Figure 5.3: DAM LMPs and hourly SR prices for Normal operation (Scenario-1).

Scenario-1: Normal Operation (No Outages or Congestion)- It is noted that the social welfare is highest in Case-3 ($6,145,987) when DR and BESS are simultaneously included in the DAM and participated in both energy and SR services as compared to Case-1 ($6,003,801) and Case-2 ($6,118,714). Fig. 5.3(a) depicts the LMP profile at the randomly selected bus-12, and it can be noted that the energy price reduces significantly in Case-3 as compared to Case-1 and Case-2. This is because the energy is provided via cheaper options such as DR and BESS during the peak hours (17-21) instead of costlier generators. From Fig. 5.3(b), it is noted that the hourly SR prices for Case-3 during normal operation with DR and BESS are lower as compared to Case-1, significantly during peak hours, as these resources are cheaper viable options as compared to expensive generators.

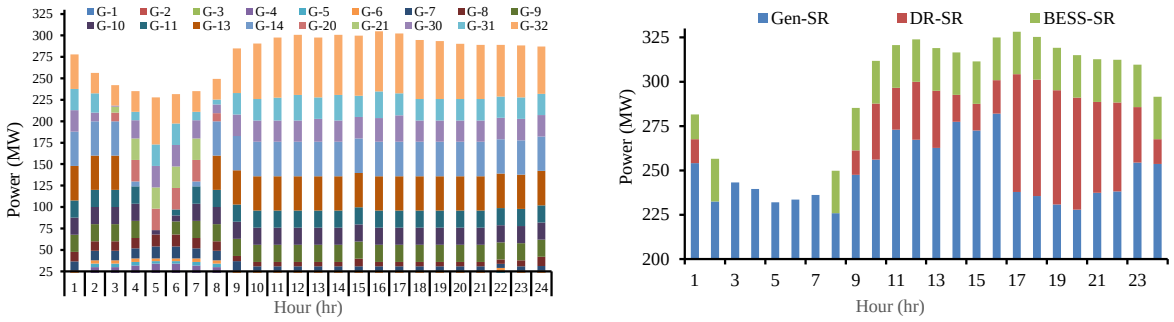
It is noted that DR services are cleared during peak hours only, *i.e.* hours 17-20 because



(a) DR dispatch (b) BESS SOC profile

Figure 5.4: DR and BESS operational profiles, Case-3, Scenario-1

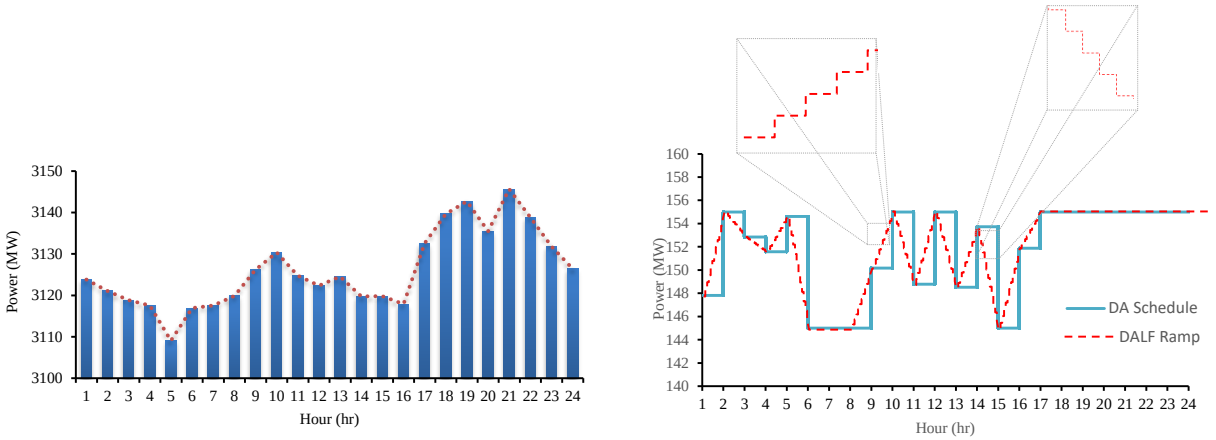
they are cheaper option during the peak hours (Fig. 5.4(a)). It is observed that most of discharging of BESS units at different buses, for Case-3, Scenario-1, occurs during peak hours 12-13 and 17-20; while charging is mainly during off-peak hours 3-8 and at hours 23, 24 to reset the final hour's SOCs to at least their initial values, for start of the next day (Fig. 5.4(b)). Fig. 5.5 describes the SR provision by generators, DR and BESS for differ-



(a) Case-1 (b) Case-3

Figure 5.5: SR provision after market clearing, Scenario-1

ent cases under Scenario-1. It is evident from the two sub-figures that the SR provided by generators decreases in Case-3 due to participation of DR and BESS in SR market. It is also observed that the LMPs during outage of a line/generator (Scenario-2a/2b), increased in all cases but the impact was lowest in Case-3 when DR and BESSs participated in markets, as compared to other cases. This is mainly because more expensive resources have to supply the load requirements which were earlier served by the generator/line on outage. The detailed results are presented by the authors in [175].

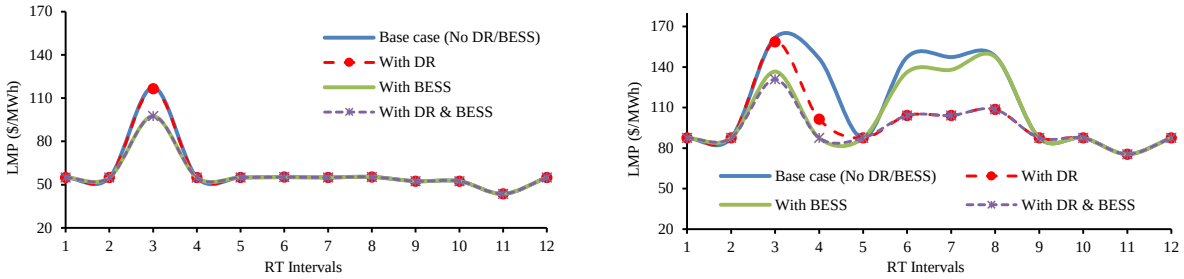


(a) Aggregated generation schedule in DAM

(b) Gen-31: DAM Schedule & DALF Ramp

Figure 5.6: Day-Ahead Load-Following (DALF) Ramp.

Day-Ahead Load-Following (DALF) Ramping- Fig. 5.6(a) presents the total cleared generation in the DAM over a 24-hr horizon, obtained using the Stage-1 model. Based on this output from DAM model, the ramping requirements for each cleared generator are obtained, in similar way as shown in Fig. 5.6(b) which presents the schedule of a randomly selected Gen-31 over the 24-hr horizon and its ramping requirement based on its day-ahead schedule, that should be considered in the RTM for each 5-min market settlement interval. The ramping curve in Fig. 5.6(b) is formulated by dividing the cleared ramp of each generator in the DAM by the number of RTM settlement intervals in an hour (*i.e.* 12, 5-min intervals) to obtain the DALF Ramp. Thus, the power outputs obtained, yield a staircase pattern for each 5-min settlement interval. The DALF Ramp of each generator are input into the Stage-2 model for RTM settlement via the proposed new ramping constraints for generators (as formulated in Section 5.4.3). With the inclusion of proposed DALF Ramp in generators' ramping constraints, the market clearing algorithm performed computationally at par with the scenario of traditional constraints for the considered 24-bus RTS. There are many benefits of considering these ramp capabilities which are discussed in detail in later subsections. The impact of considering the proposed ramping constraints on real utility systems needs to be investigated as future work.



(a) Hour-5 (b) Hour-17

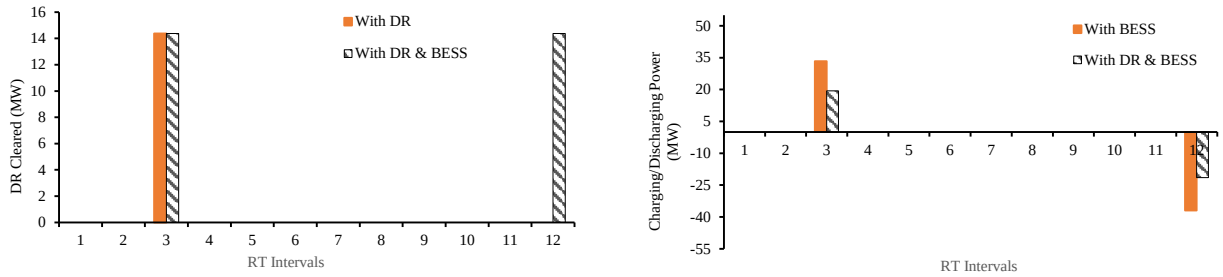
Figure 5.7: RTM LMPs at bus-15 for Normal operation (Scenario-1), Instance-3.

5.5.3 Analysis: RTM, 1-Hour Period, 5-min Settlement Intervals

In this chapter, the results are presented for all cases and scenarios as described in Table 5.3 for the three 'instances' listed in Table 5.4 for two hours, Hour-5 and Hour-17, which correspond to the lowest and highest demand respectively.

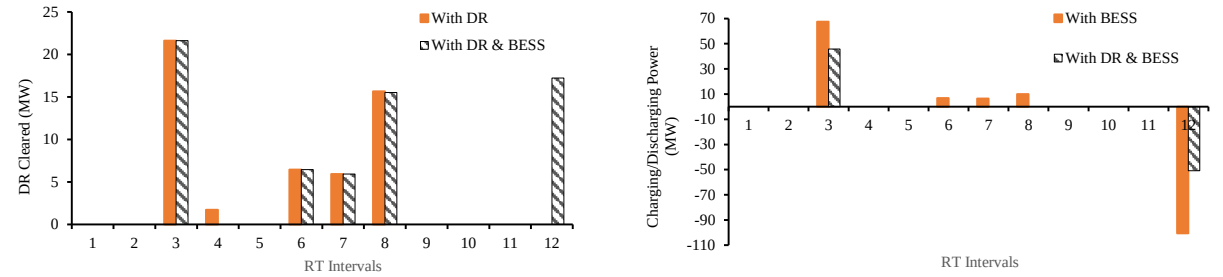
Scenario-1: Normal Operation (No Outages or Congestion)- Fig. 5.7 presents the LMP profiles at bus-15 for various cases at Instance-3 for Hour 5 and 17. It is noted from Fig. 5.7(b) that the LMP profiles in Case-4 when DR and BESS are both included in the market, are lower and flatter in comparison to other cases. At sub-interval 3, the increase in real-time demand is more than DR provision available, and consequently costlier generators need also be dispatched in Case-2 along with the DR, which is same as the dispatch in Case-1, yielding same LMPs for two cases. It can be noted that Case-4 results are smoother than Case-3 because of the presence of DR along with BESSs in the former while only BESSs in the latter. Since, the charging cost of BESS is low, there is no impact on the LMP profiles for Case-3 and 4 in Fig. 5.7(a). It can be inferred from the LMP profiles that simultaneous participation of DR and BESS in the RTM limits the drastic changes in the LMPs and the MSM framework assists in hedging the RTM prices with respect to variability in real-time demand and other uncertainties.

Fig. 5.8 and Fig. 5.9 represent the DR dispatches and BESS charging/discharging profiles for various cases at Instance-3 for Hour 5 and 17. It can be observed that during sub-intervals 6-8 when real-time demand increase is less compared to sub-intervals 3 and 11, the DR services are cleared for sub-intervals of Hour-17 and not those for Hour-5. This is because, Hour-5 is a low demand hour and the increased demand during these sub-intervals is compensated by the DALF Ramp, and there is no need for additional resources; which is not required in the proposed framework incorporating new ramping constraints. If these



(a) DR dispatch (b) BESS profile

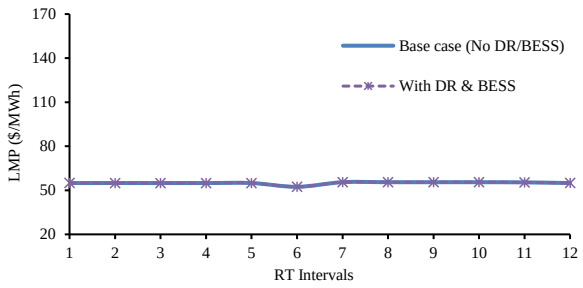
Figure 5.8: RTM DR and BESS dispatch profiles in Normal operation (Scenario-1), Instance-3, Hour-5.



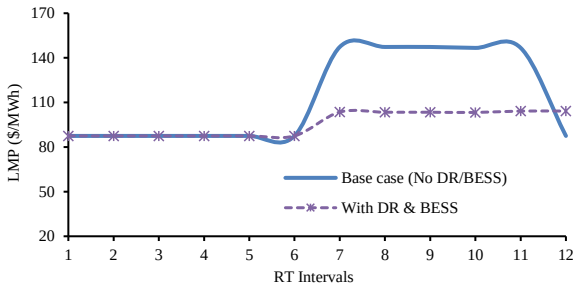
(a) DR dispatch (b) BESS profile

Figure 5.9: RTM DR and BESS dispatch profiles in Normal operation (Scenario-1), Instance-3, Hour-17.

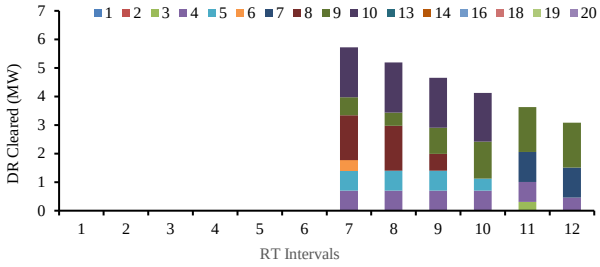
5-min ramping effect of generators based on DAM cleared schedule are not considered while settling RTM, then to compensate even small fluctuations in RTM there would be a need of additional dispatch through other available resources. Interestingly, it can be noted that during sub-interval 12 (last sub-interval of the hour), though there is no deviation in real-time demand from the day-ahead, yet DR is dispatched and BESSs are charging. These operations are to ensure the endpoint constraints for BESSs SOC (5.41), generators' day-ahead schedules (5.42) and DALF Ramp (5.14) are satisfied. For Instance-1 and 2, the results are not illustrated here due to brevity but can be interpreted from the results of Instance-3.



(a) LMP at bus-15, Hour-5



(b) LMP at bus-15, Hour-17



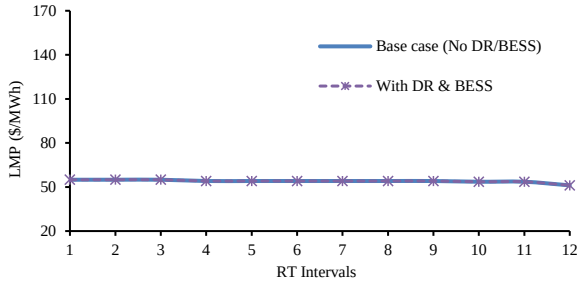
(c) DR dispatch, Hour-17

Figure 5.10: RTM LMP and DR dispatch profiles in GenOutage (Scenario-2a), Instance-3.

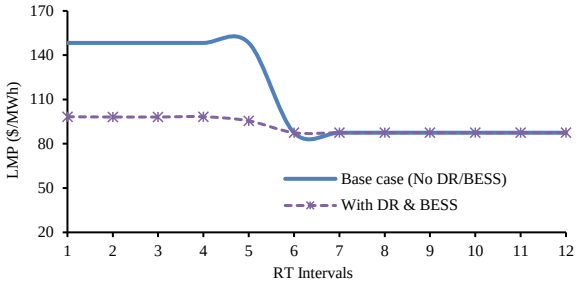
Scenario-2: Generator and Line Contingencies- Fig. 5.10(a) presents the LMP profile for all sub-intervals of Hour-5 when outage of Gen-16 occurs during sub-intervals 7-12. It is observed that the LMPs at bus-15 are same for Case-1 (Base) and Case-4 (DR+BESS), because Gen-16, dispatched at 10 MW in the DAM, is compensated by the available DALF Ramp. However, when the outage takes place at Hour-17, sub-intervals 7-12, the LMPs at bus-15 (Fig. 5.10(b)) increases for both the cases; increase in Case-1 (Base) is significantly

high because the available DALF Ramp is not sufficient and more expensive resources are dispatched. In Case-4 (DR+BESS) the participation of DR and BESS significantly flattens the LMP profile, although in actual, the BESS units do not have to participate because the Gen-16 was dispatched at 10 MW only. Fig. 5.10(c) shows the DR cleared during this contingency.

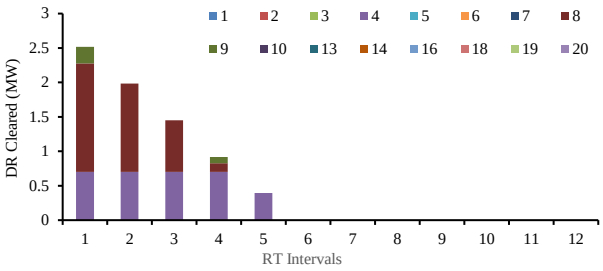
From above discussions, it can be intuitively concluded that the LMP profiles for Case-2 will also be same as Case-4 because the demand, during Gen-16 outage, was met by the DALF Ramp and DR only. On the other hand, LMP profiles for Case-3 will be somewhere in between those of Case-1 and Case-4 because of the presence of BESSs which have higher offer prices than DR. In order to analyze Case-4 over Case-2, additional scenarios with a larger generator on outage were studied. It was noted that the LMPs increased significantly in Case-1, flattened somewhat in the presence of BESS (Case-3), flatter with DR only (Case-2) and the least impacted with DR and BESS (Case-4), with both being dispatched.



(a) LMP at bus-15, Hour-5



(b) LMP at bus-15, Hour-17



(c) DR dispatch, Hour-17

Figure 5.11: RTM LMP and DR dispatch profiles in LineOutage (Scenario-2b), Instance-3.

Similarly, Fig. 5.11 present the results for a line outage (Scenario-2b). The observations

from the results of Scenario-2b are similar to those of Scenario-2a because the load has to be supplied by some other transmission line(s), hence, more expensive resources are dispatched which impacts the LMPs. This also might as well impact the total system losses. And depending on the case being considered, different market participants (DALF Ramp, DR, or BESS) get cleared and dispatched in the RTM. And it was noticed that the LMPs increased the most for Case-1, followed by Case-2, Case-3 and the lowest for Case-4. Based on the results of these outage scenarios, it can be concluded that the DALF Ramp and the simultaneous participation of DR & BESS hedges the energy price during outages in the RTM, as well.

Furthermore, the results of the RTM studies presented in this section for various scenarios and cases examine the impact of simultaneous inclusion of DR & BESS and demonstrate the implicit benefit of including DALF Ramp in the MSM. The proposed model treats balancing services availed at the 12^{th} sub-interval of each hour to ensure endpoint constraints as an exogenous parameter, determined external to the RTM auction model.

5.5.4 Sensitivity Analysis

Detailed sensitivity studies are carried out to examine the impact of inclusion of the proposed novel DALF Ramp in the MSM framework (coordinated DAM + RTM) and the effects of operational and physical characteristics of DR and BESS participants, such as their level of participation, initial SOC, DCR, etc. on the market settlements and overall dispatch.

Effect of Inclusion of DALF Ramp

Detailed comparison for RTM settlement, without and with DALF Ramp constraints, for Case-1: Base case (no DR & BESS) and Case-4 (with DR & BESS), are carried out. Fig. 5.12 presents the DALF Ramp available at various generators at Hours-4, 5, 16 and 17, and the net sum of DALF Ramp from all generators, at these hours. The following observations are made:

Hour-5: Low demand hour

- In Case-1 and Case-4, the social welfare for RTM with DALF Ramp increased by \$3,467 and \$5,007 in Hour-5, or 1.67% and 1.95% increases, respectively, with reference to the RTM without DALF Ramp.

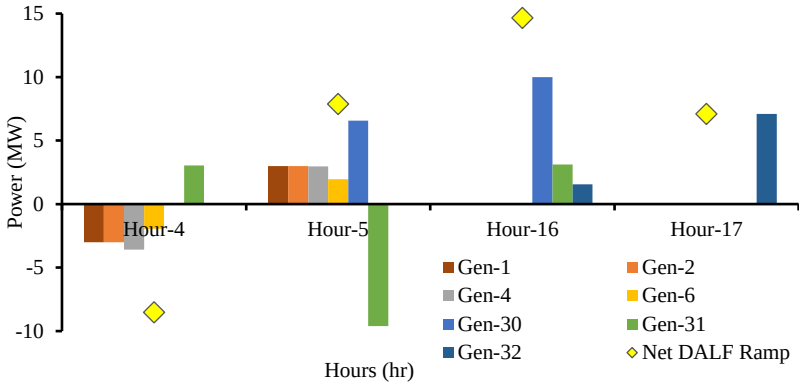


Figure 5.12: Scheduled DALF Ramps across generators.

- The 1.67% increase in social welfare in Case-1, can be attributed to the introduction of the DALF Ramp, as there is no DR or BESS. While the 1.95% increase in Case-4 can mostly be attributed to DALF Ramp with some contribution from DR and BESS.

Hour-17: High demand hour

- In Case-1 and Case-4, the social welfare for RTM with DALF Ramp increased by $2,582 and $3,976, or 0.89% and 1.35% increases, respectively, with reference to RTM without DALF Ramp. From Fig. 5.12 it is noted that the DALF Ramp at this hour is available only from Gen-32.

- The increase in social welfare with DALF Ramp at Hour-5 is higher than at Hour-17 because the remaining real-time demand, after considering the DALF Ramp contribution, is supplied by the marginal generator; and the marginal generator at Hour-5 is of lower offer price than the marginal generator at Hour-17.

- It is also observed from Fig. 5.12 that the net sum of all individual generators' DALF Ramps at Hour-16 is higher than that at Hour-17. Consequently, the Case-1 social welfare for RTM at Hour-16, without and with DALF Ramp constraints increased by $7,996 or 2.73% with reference to that without DALF Ramp. It can thus be inferred that the impact on social welfare increases with the amount of DALF Ramp available.

From these discussions, it can be concluded that the RTM social welfare increases when DALF Ramp is considered in the market settlement. Furthermore, the increase in social

welfare with DALF Ramp, depends on the net sum of all individual generators' DALF Ramps available and the system load conditions at an hour.

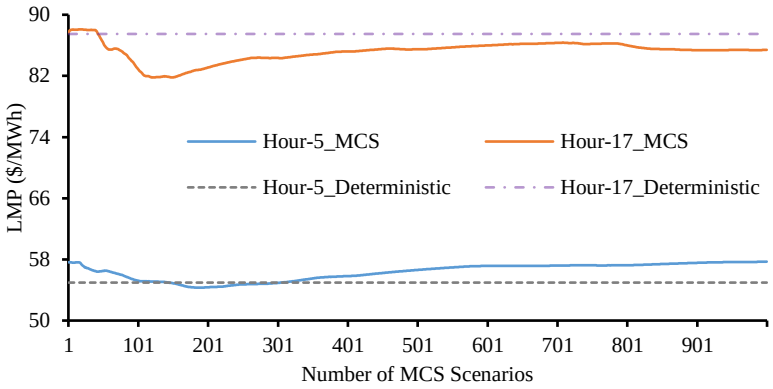


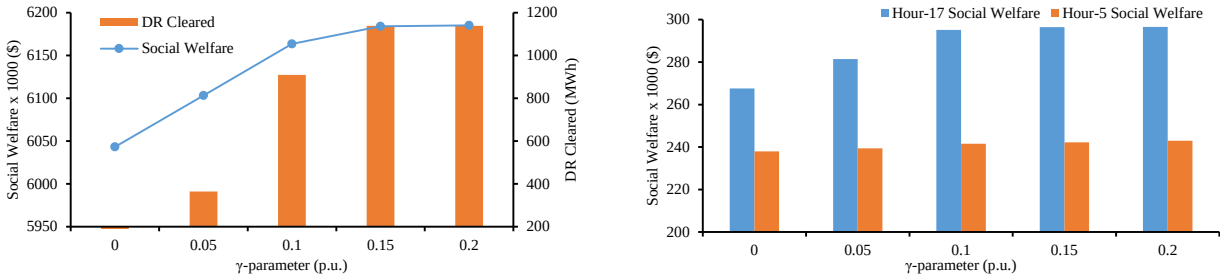
Figure 5.13: LMP profiles at bus-15 considering RES uncertainties.

Effect of RES Uncertainties

Uncertainties studies were carried out by simulating RES generation scenarios around the forecast values, in both DAM and RTM settlements, by varying the RES generation by ±5-25%. In the DAM, the RES generation was increased at off-peak hours and decreased during peak hours. It was noted that at off-peak, the most expensive generator cleared, reduced its generation; while during peak-hours, the additional generation requirement was met in the same manner as in Scenario-2a of the DAM, where a generator outage takes place. In the RTM, the uncertainty in RES generation was simulated by varying their output during 5-min sub-intervals. The effect on LMPs, compensation by DALF Ramp, dispatch of DR, BESS and generation units were similar to Scenario-2a of the RTM (generator outage).

To further examine the impact of RES uncertainties on the model performance and robustness, a Monte Carlo Simulation is carried out by varying the hourly PV and wind generation profiles to create 1,000 scenarios in the DAM settlement. Fig. 5.13 presents the expected DAM LMP at bus-15 for Hour-5 and Hour-17, demonstrating their convergence, with 4.98% and 2.39% errors, compared to the respective deterministic LMP at these hours, and robustness of the solution under uncertain conditions. The expected social welfare converged with 0.35% error, with respect to the deterministic. On the other hand, the *instances* considered in Table 5.4 reflect the changes in real-time net system demand

with reference to the DAM cleared demand. The RTM load profiles thus created for the *instances*, can be considered as representing the uncertain behaviour of PV and wind generation; hence no additional MCS studies were carried out for the RTM.

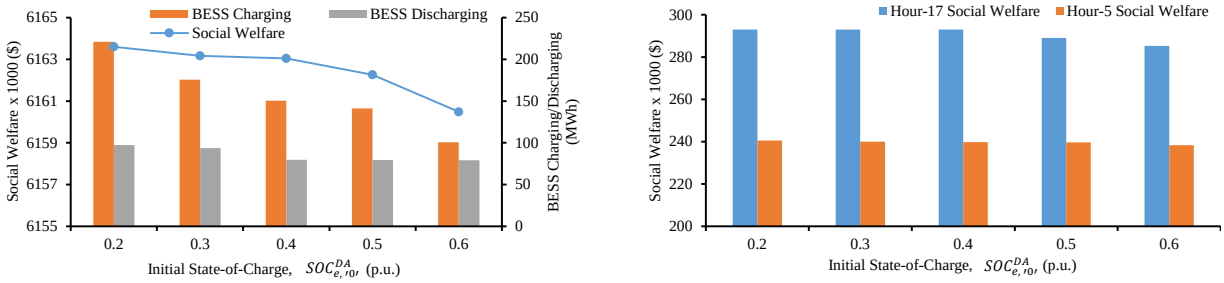


(a) DAM (b) RTM

Figure 5.14: Effect of γ-parameter on market attributes.

Effect of DR and BESS Attributes

Fig. 5.14 presents the effect of variation of DR participation (as a fraction of cleared demand), denoted by the γ-parameter, in the MSM. It can be observed from Fig. 5.14(a) that the DAM social welfare increased with γ, because of greater availability of DR services replacing the costlier generators, especially during peak hours and intervals when DR price offers are lower than generators. Furthermore, from Fig. 5.14(b), it is noted that the RTM social welfare, aggregated over one hour (Hour-5, Hour-17), increased with γ during both hours, with more significant increase during the high demand hour (Hour-17).



(a) DAM (b) RTM

Figure 5.15: Effect of initial SOC of BESS on market attributes.

Sensitivity analysis has been carried out by varying the initial SOC ($SOC^{DA}_{e,'0'}$) over a range from 0.2 to 0.6 per unit in the DAM and examining its effect on the social welfare. It was noted that the DAM social welfare decreased (Fig. 5.15(a)) with increase in $SOC^{DA}_{e,'0'}$, because of reduction in BESS charging operation during low load hours at the beginning of the 24-hour horizon and consequent decrease in discharging. Furthermore, from Fig. 5.15(b), it is noted that the RTM social welfare, aggregated over one hour (Hour-5 or Hour-17), decreased with $SOC^{DA}_{e,'0'}$ at both hours, with more significant decrease during the high demand Hour-17. Even though the total installed capacity of BESS units accounted for only 10% of the capacity of the considered IEEE 24-bus RTS, the social welfare is still impacted in both DAM and RTM, as noted from the studies.

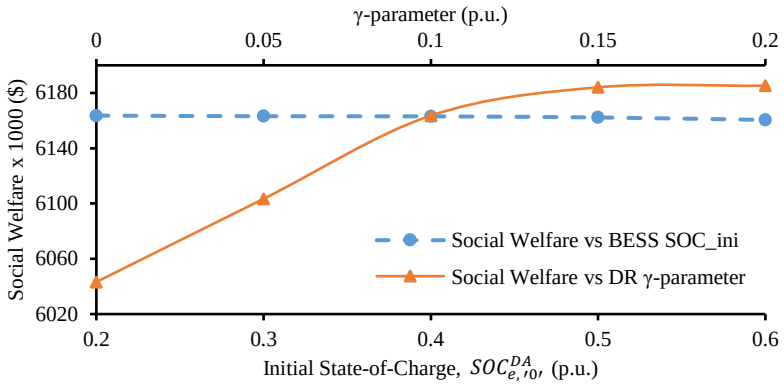


Figure 5.16: Impact of γ and initial SOC on social welfare.

To examine the inter-linkages between DR and BESS attributes, the γ-parameter and initial SOC, respectively, on market settlement, a study was carried out to obtain the DAM social welfare profile by varying each parameter over a range, one at a time. Fig. 5.16 shows the two plots for social welfare obtained by varying γ-parameter while setting $SOC^{DA}_{e,'0'} = 0.2$ and then varying $SOC^{DA}_{e,'0'}$ and setting $\gamma = 0.05$. From Fig. 5.16, it is noted that the DAM social welfares considering variation in γ and in $SOC^{DA}_{e,'0'}$ attains an equilibrium at $\gamma = 0.1$ and $SOC^{DA}_{e,'0'} = 0.4$. For any deviations in these parameters, either of the social welfares will reduce.

An additional analysis is carried out to cap the maximum value of DCR, DCR^{max}_{e}, and observe its impact on DAM settlement social welfare and the total BESS discharge energy over 24-hr horizon. From Fig. 5.17, it is noted that with higher DCR^{max}_{e}, the DAM social welfare and cleared total BESS discharged energy increases. This is attributed to more BESS discharging operation during high demand hours, which alleviates the dispatch from more expensive generators.

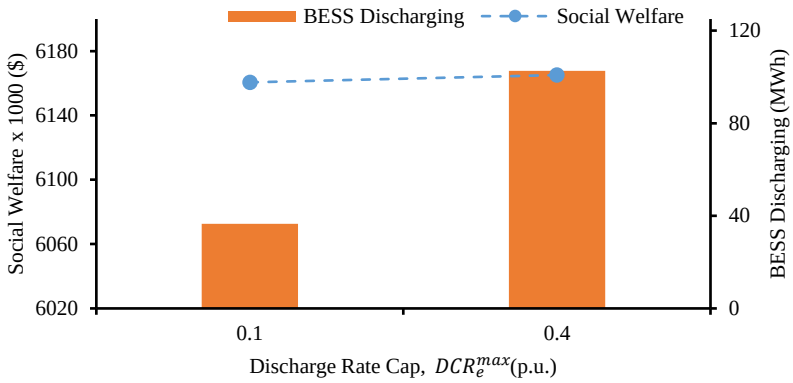


Figure 5.17: Effect of BESS discharge rate on market attributes.

5.6 Summary

In this chapter, a novel framework and comprehensive mathematical models were presented that integrated DR and BESS simultaneously in an LMP-based MSM (coordinated DAM and RTM - based on FERC's SMD structure) for a system with RES. The proposed models examined their participation in energy-cum-SR co-optimized markets in DAM and energy-balancing in RTM. A novel methodology of incorporating generator day-ahead ramping requirements in the RTM settlement, based on their cleared DAM schedule, was proposed using a set of new ramping constraints for generators, referred to as DALF Ramp. The models performance was tested on the IEEE 24-bus RTS by considering various case studies under different scenarios, uncertainty studies and sensitivity analyses.

From the results, it was inferred that the simultaneous participation of DR and BESS in MSM reduced the marginal prices for energy in the DAM as well as in the RTM, and SR prices in the DAM. It was observed that their simultaneous participation in co-optimized energy-cum-SR DAM yielded the highest social welfare. It was noted that the RTM social welfare increased with the inclusion of the proposed DALF Ramp. From the sensitivity analyses, it was noted that the DAM and RTM social welfares increased with higher DR participation, with more significant increase during the high demand hours. It was further observed that the DAM and RTM social welfares decreased with increase in the initial SOC of BESS, with more significant decrease during the high demand hours.

Consequently, it is anticipated that market participation of DR and BESS would reduce the market power of generators. It was noticed that the system with DR and BESS hedged the RTM energy prices and enhanced the system flexibility during uncertain events such as line and generator outages, change in demand or RES generation, *etc.* in the dispatch

stage. Results illustrate that the DALF Ramp affected the RTM dispatch and aided in balancing the real-time deviations. The outcomes indicated that modeling of DR & BESS and including DALF Ramp helped in capturing their operational characteristics and in providing more flexible options to ISOs for scheduling the available energy resources in DAM and dispatching them in RTM during both normal and outage scenarios.

There is significant importance of the DALF Ramp and the LMP-based DR-BESS integrated MSM framework in the context of electricity markets of the future; which will require market operators to facilitate the entry of new technologies and more readiness to adapt to changing real-time conditions and variabilities. The present work takes an important step in that direction. The main contents of this chapter have been published in [175, 178].

Chapter 6

ISO-DSO Coordinated Framework to Facilitate DER Participation in Wholesale-Retail Coupled Electricity Markets[1]

6.1 Nomenclature

Sets & Indices

i, k	Buses, $i \in I$.
e	Battery energy storage system (BESS), $e \in E$.
j	Generators (Gen), $j \in J$.
q	Time (hour), $q \in Q$.
h	Blocks of consumer bids, $h \in N_{CB}$.
g	Blocks of Gen offers, $g \in N_{GO}$.
wg	Wind generation facility, $wg \in WG$.
pv	Solar (PV) facility, $pv \in PV$.

[1]The main contents of this chapter has been reported in a manuscript currently under review for publication in *IEEE Transactions on Energy Markets, Policy and Regulation*.

E_i	BESS connected to bus i.
J_i	Generators connected to bus i.
WG_i	Wind facilities connected to bus i.
PV_i	Solar (PV) connected to bus i.
dg	Diesel generators (DGs), $dg \in DG$.
dn	Distribution nodes, $dn \in DN$.
ag	Blocks of aggregators offers, $ag \in N_{AgO}$.
r	Blocks of retail market offers, $r \in N_{RO}$.

Parameters in DAM

$BCap$	BESS energy capacity, MWh.
η	BESS round-trip efficiency, %.
C^D	Demand bid price in WDAM, \$/MWh.
C^G	Gen energy offer price in WDAM, \$/MWh.
C^{GSR}	Gen SR offer price in WDAM, \$/MW.
C^{RG}	DG energy offer price in RDAM, \$/MWh.
C^{Ag}	Aggregator offer price in WDAM, \$/MWh.
$C^{SU/DN}$	Gen start-up/shut-down cost, \$.
$C^{RSU/RDN}$	DG start-up/shut-down cost, \$.
C^{Wg}, C^{PV}	Wind/PV offer price in WDAM, \$/MWh.
C^{DRE}	DR offer price for energy in WDAM, \$/MWh.
C^{DRSR}	DR offer price for SR in WDAM, \$/MW.
C^{RDRE}	DR offer price for energy in RDAM, \$/MWh.
$C^{ch/Rch}$	BESS bid price in WDAM/RDAM, \$/MWh.
C^{BESR}	BESS SR offer price in WDAM, \$/MWh.
a, b, c, d	BESS cost coefficients.
$\overline{P}^D$	Consumer's demand bid in WDAM, MW.
$\overline{P}^{GSR}$	Gen offer for SR in WDAM, MW.

$\overline{P}^{RWg/RPV}$	Wind/solar PV offer in RDAM, MW.
$\overline{P}^{DRE/DRSR}$	DR offer for energy/SR in WDAM, MW.
$\overline{SOC}, \underline{SOC}$	BESS state-of-charge (SOC) upper/lower limits, p.u.
$\beta^{ch}, \beta^{Dch}, \beta^{SR}$	BESS charging/discharging/spinning reserve (SR) capacity share for participation, p.u.
γ	Demand response (DR) as fraction of total cleared demand, p.u.
$\alpha 1, \alpha 2$	Wind/PV capacity share for participation, p.u.
RU, RD	Ramp up/down limits of Gen and DG, MW/hr.
$\overline{P}^{G/RG}$	Upper limit on generation of Gen/DG, MW.
$\underline{P}^{G/RG}$	Lower limit on generation of Gen/DG, MW.
B	Element of susceptance matrix, p.u.
C^{RDAM}	RDAM injected power offer price, $/MWh.
$\overline{P}^{RDAM}$	RDAM injected power offer quantity, MW.
C^{RWg}, C^{RPV}	Wind/PV offer price in RDAM, $/MWh.
C^{WDAM}	WDAM injected power offer price, $/MWh.
$\overline{E}^{ch/Dch}$	Maximum BESS charging/discharging offer in Wholesale DAM (WDAM), MWh.
$\overline{E}^{Rch/RDch}$	Maximum BESS charging/discharging offer in Retail DAM (RDAM), MWh.
$\overline{P}^{ch/Dch}$	Maximum BESS charging/discharging power limits in WDAM, MW.
$\overline{P}^{Rch/RDch}$	Maximum BESS charging/discharging power limits in RDAM, MW.

Variables in DAM

$P^{D/RD}$	Demand cleared in WDAM/RDAM, MW.
$P^{G/GSR}$	Gen energy/SR offer cleared in WDAM, MW.
P^{RG}	DG energy offer cleared in RDAM, MW.
P^{Ag}	Aggregator offer cleared in WDAM, MW.
$P^{Wg/PV}$	Wind/PV generation cleared in WDAM, MW.

$P^{RWg/RPV}$	Wind/PV generation cleared in RDAM, MW.
$P^{DRE/DRSR}$	Consumers' DR cleared for energy/SR in WDAM, MW.
P^{RDRE}	Consumers' DR cleared in RDAM, MW.
$P^{ch/Dch}$	BESS charging/discharging power in WDAM, MW.
$P^{Rch/RDch}$	BESS charging/discharging power in RDAM, MW.
$E^{ch/Dch}$	BESS charging/discharging energy in WDAM, MWh.
$E^{Rch/RDch}$	BESS charging/discharging energy in RDAM, MWh.
DCR	BESS discharge rate, p.u.
SOC	BESS SOC in WDAM, p.u.
SOC^{R}	BESS SOC in RDAM, p.u.
SOC^{Dch}	BESS discharging SOC in WDAM, MWh.
SOC^{RDch}	BESS discharging SOC in RDAM, MWh.
$SOC^{SRC/SR}$	BESS capacity cleared for SR provision in WDAM, MWh/p.u.
w	1, if Gen energy offer cleared in WDAM, 0 otherwise.
w^{SR}	1, if Gen SR offer cleared in WDAM, 0 otherwise.
U, V	1, if Gen/DG start/shut-down, 0 otherwise.
W^{RG}	1, if DG committed in RDAM, 0 otherwise.
X	1, if demand bid cleared in WDAM, 0 otherwise.
$Y1, Y2$	1, if DR energy/SR offer cleared in WDAM, 0 otherwise.
$Z1, Z2, Z3$	1, if BESS charging/discharging/providing SR in WDAM, 0 otherwise.
$Z1^{R}, Z2^{R}$	1, if BESS charging/discharging in RDAM, 0 otherwise.
P_{G}^{RT}	Generation cleared from Gen in RTM, MW.
P^{loss}	Power loss in the transmission line, MW.
P^{Rloss}	Power loss in the distribution network, MW.
δ	Voltage angle, radian.
P^{RDAM}	Injected power from RDAM to WDAM, MW.
$R2$	1, if power injected from RDAM to WDAM offer cleared in WDAM, 0 otherwise.
P^{WDAM}	Injected power from WDAM to RDAM, MW.

6.2 Introduction

In this chapter, an innovative approach is presented wherein individual markets, the Wholesale Day-Ahead Market (WDAM) and Retail Day-Ahead Market (RDAM)s, are simultaneously (in parallel) and hierarchically (in sequential) settled using a novel *Co-operation Algorithm* to converge to a price equilibrium between both the markets at the coupling bus in a day-ahead horizon. Detailed mathematical models for wholesale and retail market settlements to implement the proposed, interactive parallel-hierarchical, ISO-DSOs coordinated framework considering comprehensive market constraints and DERs operational constraints are presented. Comprehensive case studies are demonstrated to show the performance of the proposed approach.

6.3 Proposed Framework for Wholesale-Retail Coupled Markets

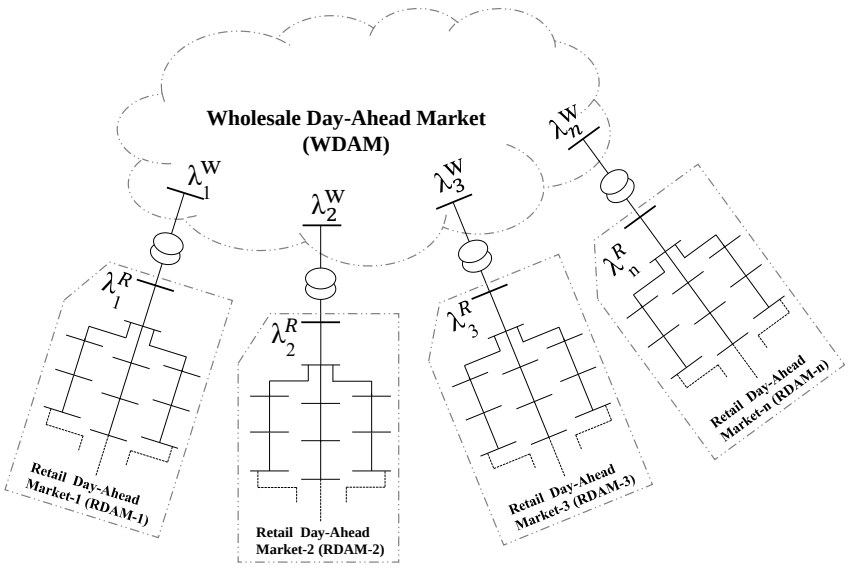


Figure 6.1: Schematic of wholesale-retail coupled markets.

This work presents a new, wholesale-retail coupled (Fig. 6.1), ISO-DSO coordinated, parallel-hierarchical framework (Fig. 6.2) wherein individual markets, the WDAM and all

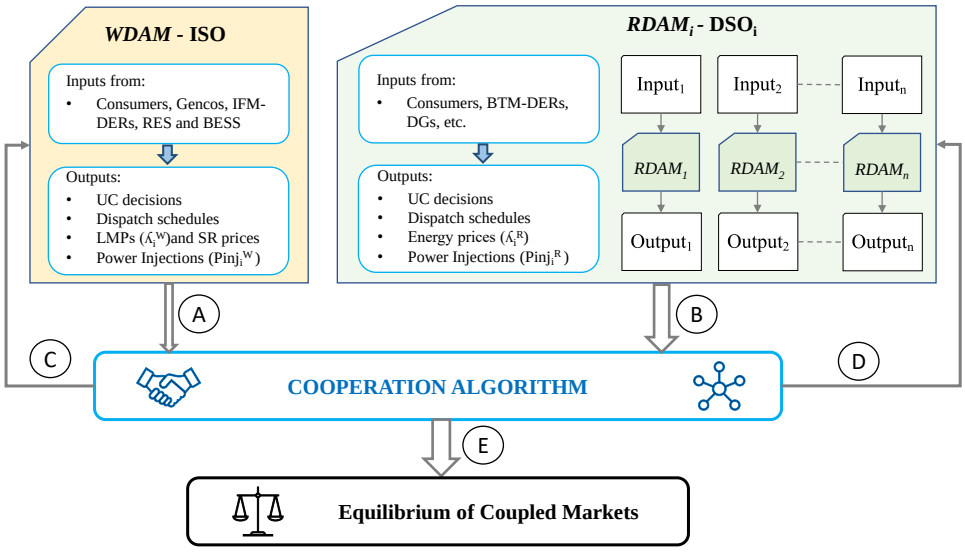


Figure 6.2: Proposed ISO-DSO coordinated framework.

the RDAMs, are settled in parallel and hierarchically updated using a novel Cooperation Algorithm (Fig. 6.3), thereby converging to an equilibrium price for all the markets at the coupling buses.

The distribution systems can be classified in various types depending upon different factors. Based on , the distribution systems broadly be classified into three categories: (a) nature of current (dc and ac distribution systems), (b) type of construction (overhead and underground systems) and (c) scheme of connection (radial, ring main and interconnected systems. In this work, we have considered the radial connection scheme of the distribution systems. The proposed framework and mathematical model could be extended to other type of distribution systems by appropriately modifying the affected terms; which may be pursued as a future work.

The proposed framework involves an iterative approach which begins with each market participant of the WDAM or the RDAMs submitting their bids/offers, and a parallel settlement of the WDAM by the ISO and the multiple RDAMs by their respective DSOs is carried out to obtain the optimal dispatches, schedules, prices, power flows, *etc.* These outcomes are utilized to perform logic operations (Fig. 6.3) using the WDAM LMPs at the coupling buses and corresponding RDAM prices at these buses, and hence determine the binary decision flags, A_i and B_i, associated with each coupling bus i. The decision flag $A_i = 1$ represents the case when RDAM$_i$ price is lower than the LMP of the coupling

bus i in the WDAM, which indicates that the corresponding retail market has cheaper DERs which can inject power into the wholesale market and thereby reduce the WDAM-LMP. Whereas, the decision flag $B_i = 1$ denotes the case when the LMP at the coupling bus i of the WDAM is lower or equal to the RDAM$_i$ price, indicating that the wholesale market has cheaper resources and can inject power to the retail market and achieve price equilibrium. Once the values of A and B parameters are determined, the algorithm checks if there are any RDAMs which can inject power into the wholesale market at a lower price. If RDAMs are available, then the next iteration of WDAM is carried out by inputting the market outcomes of all such RDAMs with $A_i = 1$ flags. On the other hand, if lower price RDAMs are not available, then the algorithm checks for price equilibrium across all the coupling buses. If there is a price mismatch at a coupling bus, the WDAM injects power into expensive RDAMs.

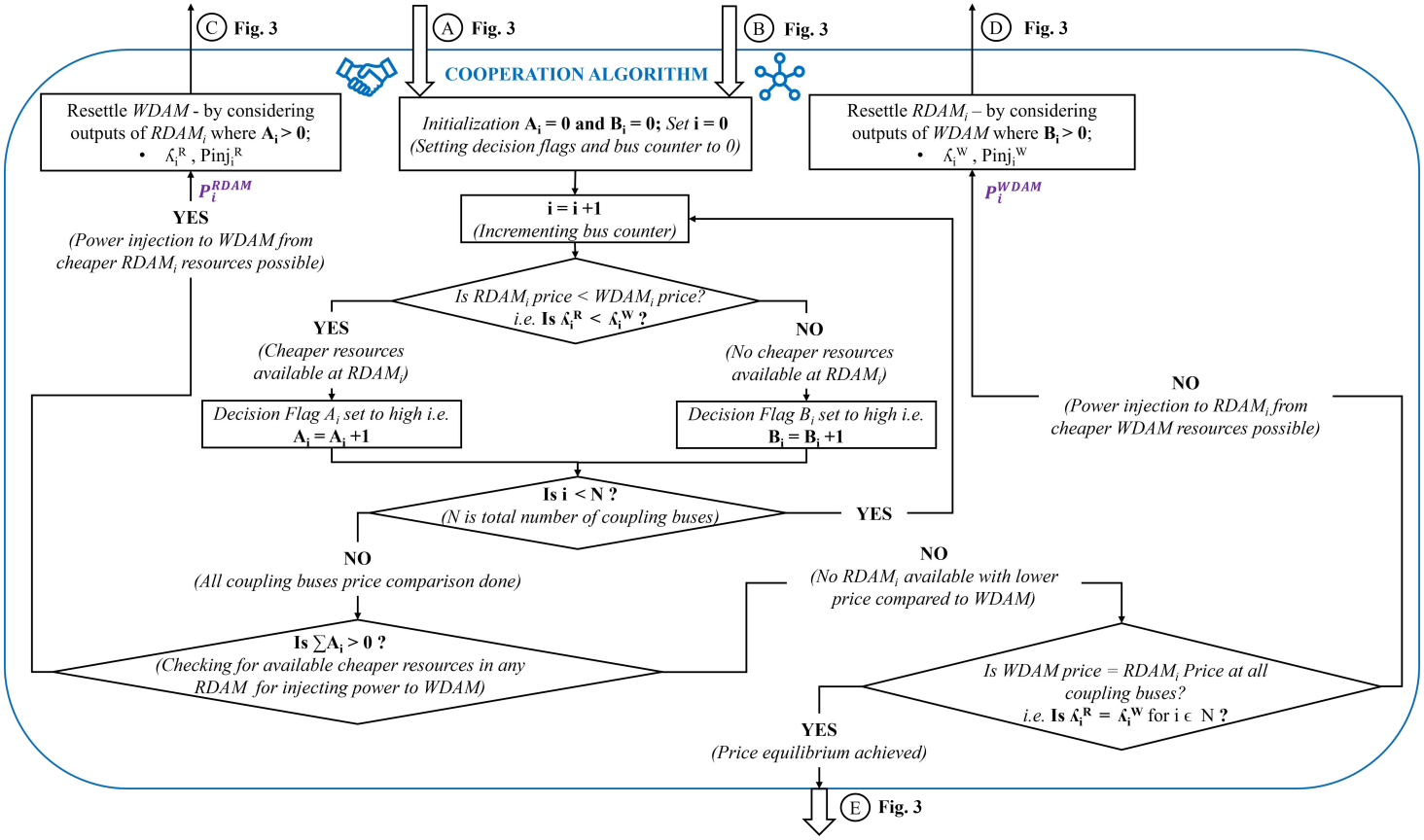


Figure 6.3: Schematic of the proposed Cooperation Algorithm.

The successive iterations will be hierarchically executed, which means either the WDAM or RDAMs will be carried out. Once, the WDAM has been performed, then the updated outcomes of WDAM and related RDAM which have non-zero A_i flags are fed into the next step. Consequently, the decision flags are updated based on the changes of the previous step and will continue until all A_i flags are zero. Thereafter, all RDAM corresponding to non-zero B_i flags are carried out for the next iteration based on the previous step's updated inputs. The loop goes on until it converges. The algorithm converges when the market prices at all the coupling buses for wholesale and retail levels (coupling point of wholesale-retail systems is shown in Fig. 6.1) are equal while satisfying the set of market and operational constraints. Table 6.1 presents the operational rules, sub-rules and corresponding actions corresponding to the proposed framework for various scenarios of WDAM and RDAM price relationships. In Table 6.1, the first column represents the scenarios pertaining to all possible relations between WDAM and RDAM energy prices. While the second column shows the possible cases of the power imported or exported by RDAM to WDAM, denoted by term $Pinj^R$ and the third column depicts the corresponding actions suggested based on the algorithm. All bids/offers, at both wholesale and retail levels, are received only once at the beginning of the process; *i.e.*, bids/offers are received once by the ISO for the WDAM and the DSOs for the RDAMs, a few hours before the day-ahead settlements. The Cooperation Algorithm is then executed and the market settlement outcomes are released once, after the convergence of the algorithm.

There might arise cases wherein the convergence is not achieved at some of the coupling buses during congestion, with shortage of resources at the receiving-end buses of congested lines or due to lack of resources at some coupling buses. In such cases, the WDAM LMP at those coupling buses will be the governing market prices and considered as master, which will be communicated to the DSOs at the connected RDAM to follow.

Table 6.1: Operational Rules and Actions

Rules	**Sub-rules**	**Actions**
$\lambda_i^W < \lambda_i^R$	Sub-rule-1: $Pinj_i^R \leq 0$	RDAM next iteration
	Sub-rule-2: $Pinj_i^R > 0$	RDAM next iteration
$\lambda_i^W > \lambda_i^R$	Sub-rule-1: $Pinj_i^R \leq 0$	RDAM next iteration
	Sub-rule-2: $Pinj_i^R > 0$	WDAM next iteration
$\lambda_i^W = \lambda_i^R$	Sub-rule-1: $Pinj_i^R \leq 0$	Converge, STOP
	Sub-rule-2: $Pinj_i^R > 0$	Converge, STOP

6.4 Mathematical Models of Proposed Wholesale-Retail Coupled Day-Ahead Markets

6.4.1 Wholesale Day-Ahead Market (WDAM)

Objective Function

To maximize the social welfare, given by (6.1) below. The first term in (6.1) denotes the consumers' gross surplus and the second term represents the charging cost of BESS. The third and fourth terms denote the total cost of energy supply from RES which are participating directly in the wholesale market. The fifth term denotes the operational cost of generators including energy and SR provisions. The sixth term represents the cost of DR provisions in energy and SR markets, respectively. The BESS discharging cost is given by the seventh term. The start-up and shut-down cost of generators are denoted by the eighth term. The ninth term represents the cost of SR provision by BESS and the tenth term in (6.1) represents the total cost of power injected (P^{RDAM}) from the retail market into the wholesale market at coupling buses. Note that P^{RDAM} is set to zero initially and subsequently, based on the comparative prices between WDAM and RDAM, and as per Cooperation Algorithm (Fig. 6.3), the P^{RDAM} values will be considered as inputs to the wholesale market for subsequent iterations. Equation (6.1), excluding term (b), represents the objective function of the WDAM of the proposed framework. Whereas, if the same equation is considered with the exclusion of term (a) and the inclusion of term (b), it corresponds to the objective function for aggregator-based WDAM in the sequential

structure.

$$
\begin{aligned}
J = & \underbrace{\sum_{q\epsilon Q}\sum_{h\epsilon N_{CB}}\sum_{i\epsilon I}(C^{D}_{i,h,q}P^{D}_{i,h,q})}_{\text{(Consumers' Gross Surplus)}} + \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(C^{ch}_{e,q}E^{ch}_{e,q})}_{\text{(BESSs' Charging Costs)}} \\
& \underbrace{-\sum_{q\epsilon Q}\sum_{wg\epsilon WG}(C^{Wg}_{wg,q}P^{Wg}_{wg,q}) - \sum_{q\epsilon Q}\sum_{pv\epsilon PV}(C^{PV}_{pv,q}P^{PV}_{pv,q})}_{\text{(Energy Supply Costs from RES (Wind and Solar))}} \\
& \underbrace{-\sum_{q\epsilon Q}\sum_{j\epsilon J}\sum_{g\epsilon N_{GO}}(C^{G}_{g,j,q}P^{G}_{g,j,q} + C^{GSR}_{g,j,q}P^{GSR}_{g,j,q})}_{\text{(Gencos' Energy and SR Supply Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{h\epsilon N_{CB}}\sum_{i\epsilon I}(C^{DRE}_{i,h,q}P^{DRE}_{i,h,q} + C^{DRSR}_{i,h,q}P^{DRSR}_{i,h,q})}_{\text{(DR Energy and SR Provision Costs)}} \\
& \underbrace{-\sum_{q\epsilon Q}\sum_{e\epsilon E}(a_e SOC^{Dch}_{e,q} + b_e SOC^{Dch}_{e,q-1} + c_e DCR_{e,q} + d_e)}_{\text{(BESSs' Discharging Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{j\epsilon J}(C^{SU}_{j,q}U_{j,q} + C^{DN}_{j,q}V_{j,q})}_{\text{(Gencos' Start-up and Shut-down Costs)}} \\
& \underbrace{-\sum_{q\epsilon Q}\sum_{e\epsilon E}(C^{BESR}_{e,q}SOC^{SRC}_{e,q})}_{\text{(BESS SR Provision Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{r\epsilon N_{RO}}\sum_{i\epsilon I}(C^{RDAM}_{i,r,q}P^{RDAM}_{i,r,q})}_{\text{(a: proposed framework)}} - \underbrace{\sum_{q\epsilon Q}\sum_{ag\epsilon N_{AgO}}\sum_{i\epsilon I}(C^{Ag}_{i,ag,q}P^{Ag}_{i,ag,q})}_{\text{(b: sequential)}}
\end{aligned}
\tag{6.1}
$$

The objective function is subjected to following constraints.

Demand-Supply Balance

These constraints with exclusion of term (d), denote the WDAM demand-supply balance for the proposed framework, formulated using dc load flow equations and includes line losses [120]. If term (c) is excluded and term (d) is included in (6.2), these constraints represent the aggregator-based WDAM demand-supply balance.

$$
\begin{aligned}
\sum_{j\epsilon J_i}P^{G}_{j,q} + \sum_{wg\epsilon WG_i}P^{Wg}_{wg,q} + \sum_{pv\epsilon PV_i}P^{PV}_{pv,q} + P^{DRE}_{i,q} + \underbrace{P^{RDAM}_{i,q}}_{\text{(c)}} + \underbrace{P^{Ag}_{i,q}}_{\text{(d)}} + \sum_{e\epsilon E_i}P^{Dch}_{e,q} - \sum_{e\epsilon E_i}P^{ch}_{e,q} - P^{D}_{i,q} \\
= \sum_{k\epsilon I}(0.5P^{loss}_{i,k} + B_{i,k}(\delta_{i,q} - \delta_{k,q})) \quad \forall i\,\epsilon\, I,\ \forall q\,\epsilon\, Q
\end{aligned}
\tag{6.2}
$$

Market Clearing Constraints

The following constraints ensure that the market cleared quantities of generators' supply for energy (6.3) and SR service (6.4), consumers' demand (6.5), DR quantity for energy

(6.6) and SR service (6.7), and BTM-DERs injected power from the RDAMs (6.8), are within their maximum respective limits.

$$P^{G}_{g,j,q} \leq \overline{P}^{G}_{g,j,q}\, w_{g,j,q} \qquad \forall j \epsilon J,\ \forall q \epsilon Q,\ \forall g \epsilon N_{GO} \tag{6.3}$$

$$P^{GSR}_{g,j,q} \leq \overline{P}^{GSR}_{g,j,q}\, w^{SR}_{g,j,q} \qquad \forall j \epsilon J,\ \forall q \epsilon Q,\ \forall g \epsilon N_{GO} \tag{6.4}$$

$$P^{D}_{i,h,q} \leq \overline{P}^{D}_{i,h,q}\, X_{i,h,q} \qquad \forall i \epsilon I,\ \forall q \epsilon Q,\ \forall h \epsilon N_{CB} \tag{6.5}$$

$$P^{DRE}_{i,h,q} \leq \overline{P}^{DRE}_{i,h,q}\, Y1_{i,h,q} \quad \forall i \epsilon I,\ \forall q \epsilon Q,\ \forall h \epsilon N_{CB} \tag{6.6}$$

$$P^{DRSR}_{i,h,q} \leq \overline{P}^{DRSR}_{i,h,q}\, Y2_{i,h,q} \ \forall i \epsilon I,\ \forall q \epsilon Q,\ \forall h \epsilon N_{CB} \tag{6.7}$$

$$P^{RDAM}_{i,r,q} \leq \overline{P}^{RDAM}_{i,r,q}\, R2_{i,r,q} \ \forall i \epsilon I,\ \forall q \epsilon Q,\ \forall r \epsilon N_{RO} \tag{6.8}$$

The following constraints ensure that the WDAM cleared quantities of BESS energy and power during charging/discharging mode at an hour are within their respective maximum limits. The associated binary variables for BESS charging and discharging operation at an hour are given by $Z1_{e,q}$ and $Z2_{e,q}$, respectively.

$$E^{ch}_{e,q} \leq \overline{E}^{ch}_{e,q} Z1_{e,q}; P^{ch}_{e,q} \leq \overline{P}^{ch}_{e,q} Z1_{e,q} \quad \forall e \epsilon E,\ \forall q \epsilon Q \tag{6.9}$$

$$E^{Dch}_{e,q} \leq \overline{E}^{Dch}_{e,q} Z2_{e,q}; P^{Dch}_{e,q} \leq \overline{P}^{Dch}_{e,q} Z2_{e,q} \ \forall e \epsilon E,\ \forall q \epsilon Q \tag{6.10}$$

DR Constraints

These constraints ensure that the DR quantity cleared in the energy and SR markets are from cleared quantity of demand, only.

$$P^{DRE}_{i,q} + P^{DRSR}_{i,q} \leq \gamma P^{D}_{i,q} \qquad \forall i \epsilon I,\ \forall q \epsilon Q \tag{6.11}$$

BESS Energy Arbitrage and Operational Constraints

The grid-connected BESS units participating in the WDAM provide energy and SR services, while the BTM-DER type BESS units participating via DSOs provide energy only, complying with existing market rules (FERC Order 841 and Order 2222).

The SOC of a BESS, participating in the WDAM is governed by the dynamic energy balance relation considering its SOC at the previous hour and the charging/discharging operation at the hour, given as follows:

$$(SOC_{e,q} - SOC_{e,q-1})BCap_e = P^{ch}_{e,q}\eta_e - P^{Dch}_{e,q}/\eta_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.12}$$

The energy cleared in the WDAM of a BESS for charging/discharging operation are as follows:

$$E^{ch}_{e,q} = P^{ch}_{e,q}\eta_e; E^{Dch}_{e,q} = P^{Dch}_{e,q}/\eta_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.13}$$

The following constraints ensure that the SOC of the BESS at any hour is within the limit, in charging and discharging modes, respectively:
Charging mode:

$$SOC_{e,q} - SOC_{e,q-1} \leq \beta^{ch}_{e,q}(\overline{SOC_e} - SOC_{e,q-1}) + (1 - Z1_{e,q})\overline{SOC_e} \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.14}$$

Discharging mode:

$$SOC_{e,q-1} - SOC_{e,q} \leq (1 - Z2_{e,q})\overline{SOC_e} + \beta^{Dch}_{e,q}(SOC_{e,q-1} - SOC^{SR}_{e,q-1} - \underline{SOC_e}) \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.15}$$

where β^{ch} and β^{Dch} are BESS parameters denoting their level of participation, as a fraction of their available capacity in charging/discharging services in the WDAM. Note that when BESS is charging, (6.14) becomes an active constraint while (6.15) is redundant, whereas when discharging, (6.15) is an active constraint and (6.14) becomes redundant.

End-point SOC Constraint: This constraint ensure that the SOC of the BESS is at least at the same level at the end of day, as it was at the start.

$$SOC_{e,'0'} \leq SOC_{e,'24'} \qquad \forall e \,\epsilon\, E \tag{6.16}$$

BESS SR Constraints

This constraint ensures that the SR cleared from BESS is within its maximum offer quantity; β^{SR} denotes the fraction of total capacity available for SR.

$$SOC^{SR}_{e,q} \leq \beta^{SR}_{e,q}\,\overline{SOC_e}\,Z3_{e,q} \qquad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.17}$$

Other Constraints

These include UC constraints and coordination constraints for DR and BESS to ensure that DR blocks are cleared in accordance to the cleared demand bid blocks, and to prevent simultaneous discharging and charging operation of a BESS unit [120, 175].

6.4.2 Retail Day-Ahead Market (RDAM)

Objective Function

To minimize the payment made by an individual DSO to the entities supplying energy in the RDAM, given as follows:

$$
\begin{aligned}
J = & \underbrace{\sum_{q\epsilon Q}\sum_{wg\epsilon WG}(C^{RWg}_{wg,q}P^{RWg}_{wg,q}) + \sum_{q\epsilon Q}\sum_{pv\epsilon PV}(C^{RPV}_{pv,q}P^{RPV}_{pv,q})}_{\text{(Energy Supply Costs from RES (Wind and Solar))}} + \underbrace{\sum_{q\epsilon Q}\sum_{dg\epsilon DG}\sum_{g\epsilon N_{GO}}(C^{RG}_{g,dg,q}P^{RG}_{g,dg,q})}_{\text{(DGs' Energy Supply Costs)}} \\
& + \underbrace{\sum_{q\epsilon Q}(C^{WDAM}_{i,q}P^{WDAM}_{i,q})}_{\text{(Power Imported Costs from WDAM)}} + \underbrace{\sum_{q\epsilon Q}\sum_{h\epsilon N_{CB}}\sum_{dn\epsilon DN}(C^{RDRE}_{dn,h,q}P^{RDRE}_{dn,h,q})}_{\text{(DR Energy Supply Costs)}} - \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(C^{Rch}_{e,q}E^{Rch}_{e,q})}_{\text{(BESSs' Charging Surplus)}} \\
& + \underbrace{\sum_{q\epsilon Q}\sum_{e\epsilon E}(a_e SOC^{RDch}_{e,q} + b_e SOC^{RDch}_{e,q-1} + c_e DCR_{e,q} + d_e)}_{\text{(BESSs' Discharging Costs)}} + \underbrace{\sum_{q\epsilon Q}\sum_{dg\epsilon DG}(C^{RSU}_{dg,q}U_{dg,q} + C^{RDN}_{dg,q}V_{dg,q})}_{\text{(DGs' Start-up and Shut-down Costs)}}
\end{aligned}
\tag{6.18}
$$

The first and second terms in (6.18) represents the total cost of energy supply from RES participating directly in the RDAM. The third term denotes the payment by the DSO towards operational cost of diesel-fed generators. The fourth term represents the total payment by the DSO for the power imported at the coupling substation from the WDAM to serve the distribution system loads. The injected power P^{WDAM} is set to zero initially and based on the proposed algorithm (Fig. 6.3), are updated for subsequent iterations to serve as inputs to the respective RDAMs. The fifth term denotes the payment to consumers offering DR provisions. The BESS charging revenue and discharging payments are denoted by the sixth and seventh terms, respectively. The start-up and shut-down costs of Diesel Generators (DGs) are represented by the last term. The objective function is subjected to the following constraints.

Demand-Supply Balance

This constraint ensures the demand and supply balance at an ISO-DSO coupling bus *'i'*, at each hour at the retail level.

$$\sum_{dg\epsilon DG} P^{RG}_{dg,q} + \sum_{wg\epsilon WG} P^{RWg}_{wg,q} + \sum_{pv\epsilon PV} P^{RPV}_{pv,q} + \sum_{dn\epsilon DN} P^{RDRE}_{dn,q} - \sum_{dn\epsilon DN} P^{RD}_{dn,q} + P^{WDAM}_{i,q} + \sum_{e\epsilon E} P^{RDch}_{e,q} - \sum_{e\epsilon E} P^{Rch}_{e,q} = P^{Rloss}_{i,q} \quad (6.19)$$

wherein, the distribution losses are assumed to be 8% of the total demand, as follows:

$$P^{Rloss}_{i,q} = 0.08 \sum_{dn\epsilon DN} P^{RD}_{dn,q} \qquad \forall i \,\epsilon\, I,\ \forall q \,\epsilon\, Q \quad (6.20)$$

The RDAM of a given DSO is formulated by considering a single bus system *i.e.* aggregating the downward distribution system at the coupling bus of the WDAM. Thus, an UMP market settlement is considered for the RDAMs. The model can be extended to the DLMP pricing mechanism with modifications. Since the aim of this work is to showcase an equitable and effective framework for facilitating BTM-DERs participation in markets, the UMP market settlement is adopted as it is adequate for the purpose.

DR Constraints

These constraints ensure that the quantity of DR cleared in the RDAM is limited by a fraction of the expected demand at a node at that hour.

$$P^{RDRE}_{dn,q} \leq \gamma P^{RD}_{dn,q} \qquad \forall dn \,\epsilon\, DN,\ \forall q \,\epsilon\, Q \quad (6.21)$$

where γ is a parameter determined by the participating consumer, and it denotes the share of expected demand that the consumer can provide as DR provision.

BESS Energy Arbitrage and Operational Constraints

The SOC of a BTM-DER type BESS, participating in the DSO operated RDAM, at any hour, is obtained from the dynamic energy balance relationship considering its SOC at previous hour and its charging/discharging operation at the hour, given as follows:

$$(SOC^{R}_{e,q} - SOC^{R}_{e,q-1})BCap_e = P^{Rch}_{e,q}\eta_e - P^{RDch}_{e,q}/\eta_e \quad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \quad (6.22)$$

The BESS energy cleared in the RDAM for charging and discharging operations respectively, are as follows:

$$E^{Rch}_{e,q} = P^{Rch}_{e,q}\eta_e; E^{RDch}_{e,q} = P^{RDch}_{e,q}/\eta_e \; \forall e \, \epsilon \, E, \; \forall q \, \epsilon \, Q \tag{6.23}$$

The following constraints ensure that the charge/discharge schedules cleared in the DSO operated RDAM are within their maximum bid/offer quantities.

$$E^{Rch}_{e,q} \leq \overline{E}^{Rch}_{e,q} Z1^{R}_{e,q}; P^{Rch}_{e,q} \leq \overline{P}^{Rch}_{e,q} Z1^{R}_{e,q} \quad \forall e \, \epsilon \, E, \; \forall q \, \epsilon \, Q \tag{6.24}$$

$$E^{RDch}_{e,q} \leq \overline{E}^{RDch}_{e,q} Z2^{R}_{e,q}; P^{RDch}_{e,q} \leq \overline{P}^{RDch}_{e,q} Z2^{R}_{e,q} \quad \forall e \, \epsilon \, E, \; \forall q \, \epsilon \, Q \tag{6.25}$$

The following constraints ensure that the SOC of the BTM-DER type BESS at any hour is within the limit, in charging and discharging modes, respectively:
Charging mode:

$$SOC^{R}_{e,q} - SOC^{R}_{e,q-1} \leq \beta^{Rch}_{e,q}(\overline{SOC_e} - SOC^{R}_{e,q-1}) + (1 - Z1^{R}_{e,q})\overline{SOC_e} \quad \forall e \, \epsilon \, E, \; \forall q \, \epsilon \, Q \tag{6.26}$$

Discharging mode:

$$SOC^{R}_{e,q-1} - SOC^{R}_{e,q} \leq \beta^{RDch}_{e,q}(SOC^{R}_{e,q-1} - \underline{SOC_e}) + (1 - Z2^{R}_{e,q})\overline{SOC_e} \quad \forall e \, \epsilon \, E, \; \forall q \, \epsilon \, Q \tag{6.27}$$

where β^{Rch} and β^{RDch} are BESS parameters denoting their level of participation in the RDAM, as a fraction of their available capacity in charging/discharging services. Note that when BESS is charging, (6.26) becomes an active constraint while (6.27) is redundant, whereas when discharging, (6.27) is an active constraint and (6.26) becomes redundant.

Generation Limits

The generation limits of DG units and BTM-DERs, participating in the DSO operated RDAM, at any hour, are given as follows:

$$\underline{P}^{RG}_{dg} W^{RG}_{dg,q} \leq P^{RG}_{dg,q} \leq \overline{P}^{RG}_{dg} W^{RG}_{dg,q} \quad \forall dg \, \epsilon \, DG, \; \forall q \, \epsilon \, Q \tag{6.28}$$

$$P^{RWg}_{wg,q} \leq \alpha 1_{wg,q} \overline{P}^{RWg}_{wg} \qquad \forall wg \, \epsilon \, WG, \; \forall q \, \epsilon \, Q \tag{6.29}$$

$$P^{RPV}_{pv,q} \leq \alpha 2_{pv,q} \overline{P}^{RPV}_{pv} \qquad \forall pv \, \epsilon \, PV, \; \forall q \, \epsilon \, Q \tag{6.30}$$

where α is a parameter determined by the RES participant (wg and pv), and denotes the share of available capacity that it offers in the RDAM.

DG Ramping Constraints

These constraints ensure that the ramp-up/down capabilities of a DG unit at any hour are not violated.

$$P^{RG}_{dg,q} - P^{RG}_{dg,q-1} \leq RU_{dg} \qquad \forall dg \,\epsilon\, DG,\ \forall q \,\epsilon\, Q \tag{6.31}$$

$$P^{RG}_{dg,q-1} - P^{RG}_{dg,q} \leq RD_{dg} \qquad \forall dg \,\epsilon\, DG,\ \forall q \,\epsilon\, Q \tag{6.32}$$

Coordination Constraints

These ensure that the UC constraints pertaining to DGs are considered while scheduling their dispatch.

$$W^{RG}_{dg,q} - W^{RG}_{dg,q-1} \leq U_{dg,q} - V_{dg,q} \qquad \forall dg \,\epsilon\, DG,\ \forall q \,\epsilon\, Q \tag{6.33}$$

$$U_{dg,q} + V_{dg,q} \leq 1 \qquad \forall dg \,\epsilon\, DG,\ \forall q \,\epsilon\, Q \tag{6.34}$$

The following constraints prevent simultaneous charging and discharging operation of a BTM-DER type BESS:

$$Z1^{R}_{e,q} + Z2^{R}_{e,q} \leq 1 \qquad \forall e \,\epsilon\, E,\ \forall q \,\epsilon\, Q \tag{6.35}$$

6.5 Results and Discussions

The ISO operated wholesale market (WDAM) is modeled considering the IEEE 24-bus RTS [160, 161], modified to include RES such as wind and solar PV facilities, and BESS. There are 3x100 MW wind generation and 3x100 MW solar PV units, located at six different buses, the solar PV units with identical solar radiation profiles while the wind units with identical wind speed profiles for the sake of simplicity. The gencos' offers, and demand bids and DR offers from retailers and large consumers for energy and SR markets are in three price-quantity pairs [175]. The system also includes 10 BESS units of different capacities and initial SOCs, and are located at various buses. The data considered for performing the case studies in this chapter are given in Appendices A, B and C.

Each retail market (RDAM) is modeled using the well-known 33-bus distribution system [179, 180] and includes DGs and various BTM-DERs such as DR, BESS and small-scale RES (solar PV and wind) located at different nodes. In the retail markets, DG units submit supply offers while consumers with BTM-DERs submit both buy bids and supply offers for energy and DR services to their respective DSO. The WDAM and RDAMs are settled

24-hour ahead. The technical, operational and economic data of various participants for each level of market are summarized in Table 6.2 [179, 181].

To examine the performance of the proposed framework, the sequential coupling of WDAM and RDAMs is simulated, by considering an aggregator-based WDAM with the modified (6.1) and (6.2) as stated earlier, and the RDAM model settled based on inputs from the WDAM settlement. The DAM models (WDAM and RDAMs) are formulated as MIP problems in the GAMS environment [162] and solved using the CPLEX solver.

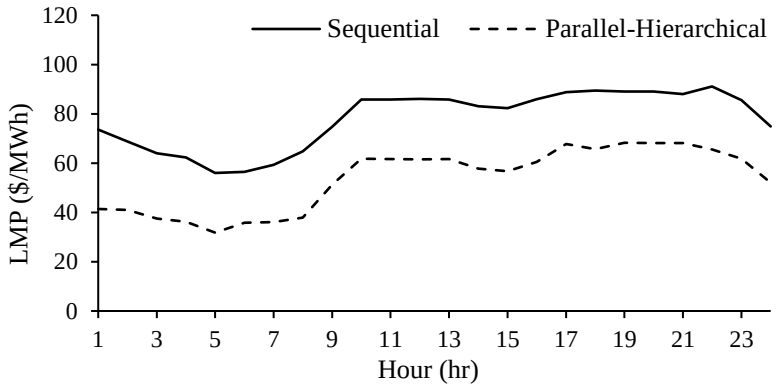
Table 6.2: Market Participants of WDAM and RDAM

Market Participant-Type	**Total Capacity (MW or MWh*)**				**CO_2 Emission (kg/MWh)**
	WDAM				
Gen (Oil)	440				530-900
Gen (Coal)	1274				660-1050
Gen (Nuclear)	1391				3-35
Gen (Hydro)	300				2-20
RES (Solar PV)	300				-
RES (Wind)	300				-
BESS (Li-Ion)	240*				-
	$RDAM_i$				
	#1	#9	#18	#24	
DGs (Diesel)	18	16.2	14.4	12.6	270-430
RES (Solar PV)	0.3	0.27	0.24	0.21	-
RES (Wind)	0.3	0.27	0.24	0.21	-
BESS (Li-Ion)	2.4*	2.16*	1.92*	1.68*	-

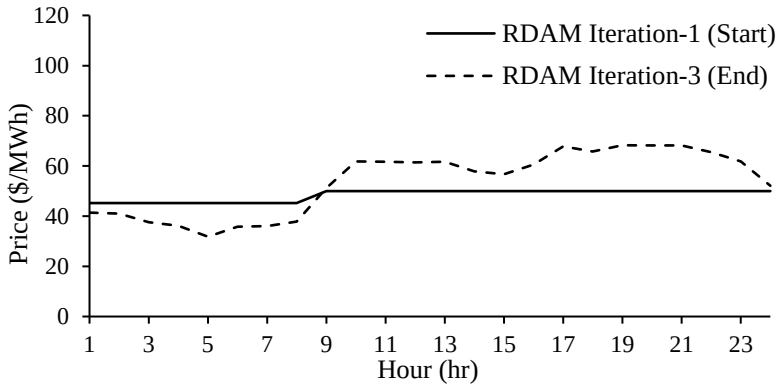
6.5.1 Normal Operation

Different sub-cases are considered to formulate some scenarios of the proposed Cooperation Algorithm (Fig. 6.3). The results are obtained for the ISO-DSOs coordinated sequential structure and compared with those obtained considering the proposed parallel-hierarchical framework wherein four DSOs are potentially capable of injecting power to the wholesale-level as part of retail market settlements.

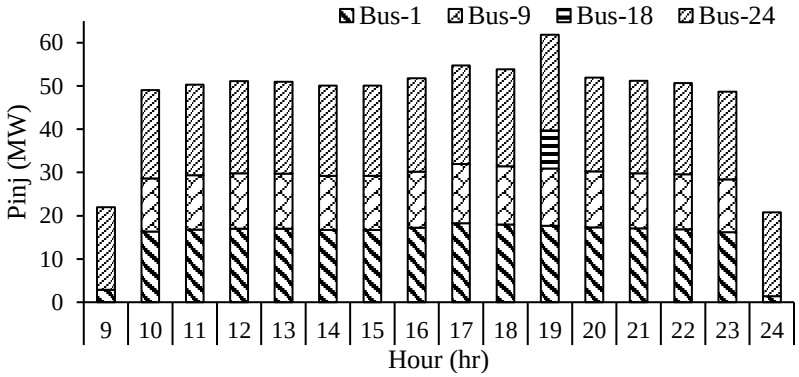
SubCase-1: WDAM-LMPs are higher, RDAMs have cheaper, surplus resources to inject power into wholesale market- Fig. 6.4(a) presents a comparison of the WDAM-LMP at



(a) WDAM-LMPs at bus-24



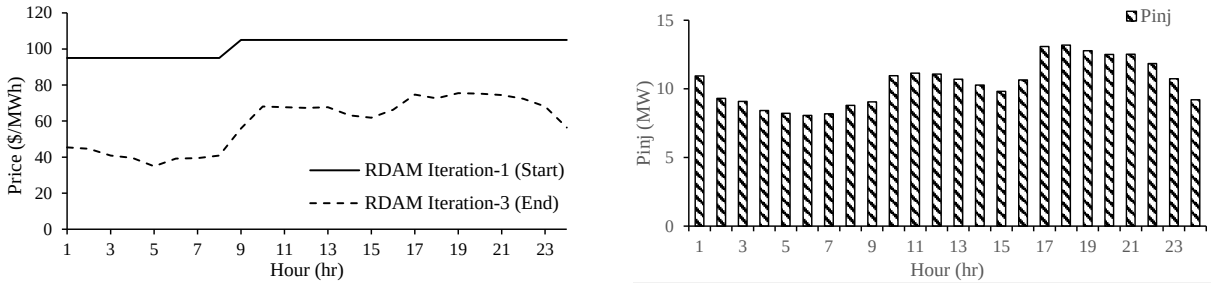
(b) RDAM price at coupling bus-24



(c) Power injected from 4-RDAMs to WDAM

Figure 6.4: WDAM-LMP profiles, RDAM price profiles and power injections from 4-RDAMs to WDAM, SubCase-1.

the randomly selected bus-24 obtained in case of sequential structure and in proposed framework. It is observed that there is a significant reduction in the WDAM-LMP in case of the proposed framework which is attributed to the small-capacity DERs cleared in the RDAM and injecting cheap, surplus energy into the WDAM. As a consequence of this power injection from the RDAM, the prices at RDAM coupling bus-24 increases, as shown in Fig. 6.4(b). It is noted from Fig. 6.4(c) that the RDAMs at coupling buses (#1, #9, #18 and #24) inject cheap power from the BTM-DERs to the WDAM during hours 9 to 24. This results in changes to the UC decisions at the wholesale market level, requiring fewer committed resources across all 24 hours, hence bringing about a reduction in the LMPs over the day as shown in Fig. 6.4(a). Finally, it is noted that the prices of the composite system (coupled WDAM and RDAM) is settled to a lower value compared to the sequential structure using the proposed framework.



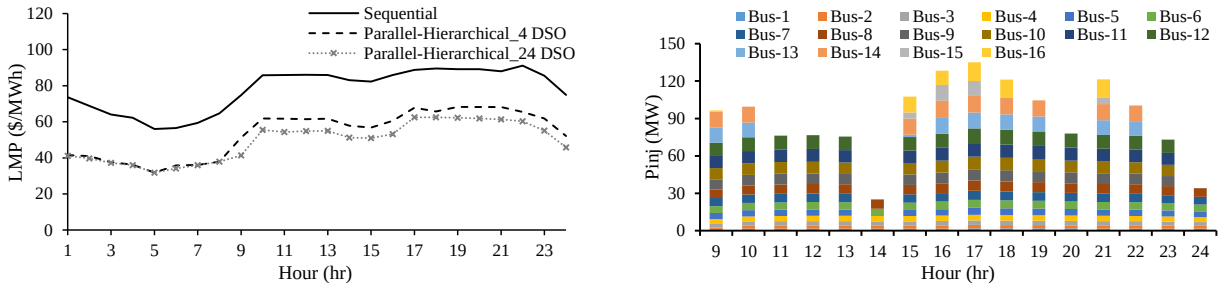
(a) RDAM prices at coupling bus-9

(b) Power injected from WDAM to RDAM

Figure 6.5: RDAM coupling bus price profiles and power injections from WDAM, SubCase-2.

SubCase-2: RDAM prices are higher, WDAM has cheaper resources to inject power into the retail markets- Fig. 6.5(a) presents the retail price at the coupling bus-9 based on the sequential structure and on the proposed parallel-hierarchical framework. It is noted that the price at the coupling bus-9 is significantly high in former case as compared to the latter, and the proposed framework assists in lowering the energy price at the distribution level when the RDAM possess expensive DERs. Fig 6.5(b) illustrates the power injected from WDAM into the RDAM connected at bus-9.

SubCase-3: Scalability and Comparison with Centralized ISO Wholesale Market- To assess the scalability of the proposed Cooperation Algorithm, all 24 DSOs are enabled to perform retail market settlements and inject power into the wholesale-level. The corresponding 24 retail distribution systems are configured to be distinct in their composition



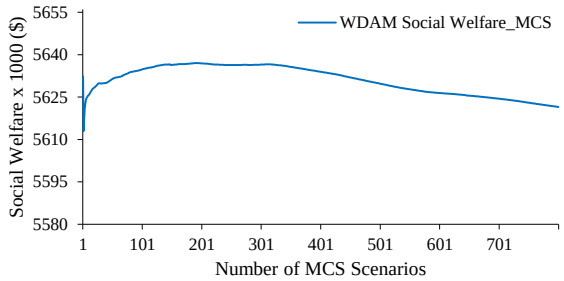
(a) WDAM-LMPs at bus-24

(b) Power injected from 24-RDAMs to WDAM

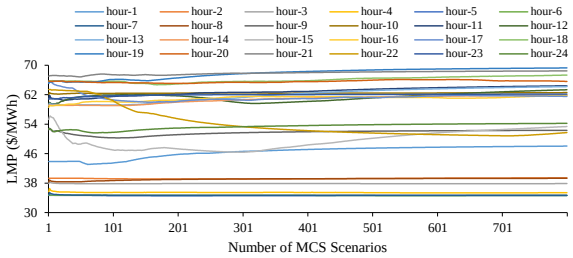
Figure 6.6: WDAM-LMP profiles and power injections from 24-RDAMs to WDAM, SubCase-3.

(in terms of their demand, BTM-DER types, bid/offer prices and quantities, participating factors such as γ, β, *etc.*) to make the sub-case generic, practical and comprehensive. The performance of this sub-case of 24 DSOs (24 RDAMs) coordinating with the ISO (WDAM) is compared with SubCase-1 where 4 DSOs (4 RDAMs) coordinate with the ISO. Fig. 6.6(a) shows the LMP profiles over a 24 hour horizon for the sequential structure and the proposed parallel-hierarchical 4-DSO and 24-DSO sub-cases. It is noted that with larger participation of DSOs, the WDAM-LMP profiles are reduced as compared to other sub-cases. This can be attributed to more BTM-DERs being cleared in the RDAMs to inject cheap, surplus energy into the wholesale level, as depicted in Fig. 6.6(b), where 16 DSOs out of 24 are cleared to inject into the WDAM at their respective coupling bus during hours 9 to 24. The Cooperation Algorithm converges efficiently for this sub-case. The computational time was negligibly affected when larger number of DSOs participated in the proposed framework: 632 seconds for SubCase-1 (4 DSOs) while 637 seconds for SubCase-3 (24 DSOs). On the other hand, the computational time for a centralized ISO wholesale market (formulated as an MIP problem and solved using the CPLEX solver) was 885 seconds, and arrived at the same optimal solution, as in the proposed method. It can be noted that the proposed model is scalable and computationally faster (about 40%) than the centralized ISO market settlement.

SubCase-4: Effect of RES Uncertainties- System operation under uncertainties have been one of the main challenges; to that effect, the impact of uncertainties in wind and solar PV are examined by carrying out a MCS, wherein the hourly wind and solar PV generation profiles are varied to create 800 scenarios in the DAM settlement. Fig. 6.7(a) shows the convergence of the expected WDAM social welfare over the MCS, with an error of 0.26% with respect to the deterministic social welfare (SubCase-1). The WDAM hourly



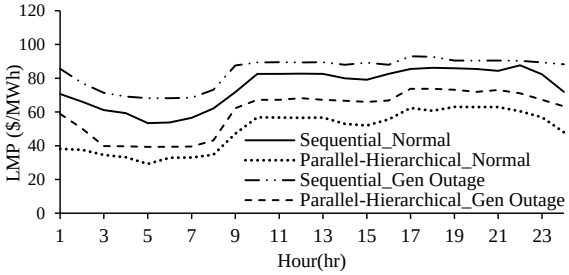
(a) WDAM expected social welfare



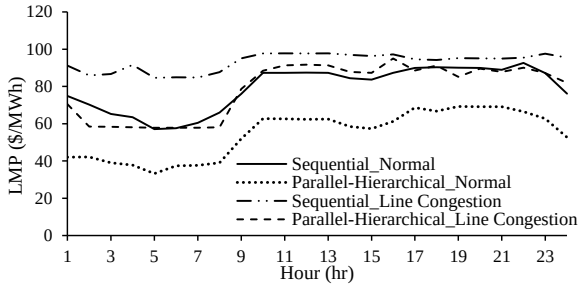
(b) WDAM hourly LMP at bus-15

Figure 6.7: WDAM expected social welfare and hourly LMP profiles considering RES uncertainties, SubCase-4.

expected LMPs at bus-15 are shown in Fig. 6.7(b), demonstrating their convergence of the solution under uncertainties. The expected WDAM-LMPs at low and peak demand hours (hour-5, hour-17) converged with 6.94% and 2.72% errors, respectively, as compared to the deterministic prices for these hours (SubCase-1). The real-time power imbalances arising from uncertainties in RES at the wholesale level and in DERs at retail levels, are expected to be handled via the balancing market, (*i.e.*, RTM), or using techniques such as Model Predictive Control and MCS.



(a) Gen-22 on outage



(b) Line 12-13 congested

Figure 6.8: LMP profiles during outage and congestion cases.

6.5.2 Outages and Congestion

Fig. 6.8(a) shows the WDAM-LMP profiles for the sequential and for the proposed frameworks (with four DSOs), considering a generator (Gen-22 of 400 MW) to be on outage

for the operating day. It is noted that the WDAM-LMP profile shifts upwards (prices increase) when the generator is on outage. This trend is noted when the WDAM is settled sequentially or in the context of the proposed framework. It can be concluded that the proposed framework helps minimize the impact of a generator outage on the market prices.

Line congestion is another common operational challenge faced by the power system operators. It is noted from Fig. 6.8(b) that when line 12-13 is congested after the WDAM settlement, there is an upward shift in the WDAM-LMP profiles in both sequential and the proposed parallel-hierarchical (considering four DSOs) frameworks. However, the price profile of the proposed framework is lower in comparison than that in the sequential settlement mechanism.

Table 6.3 consolidates the results obtained from market clearing of both the frameworks. It is noted that 769 MWh and 1,507 MWh of BTM-DERs were cleared in SubCase-1 (4-RDAMs) and SubCase-3 (24-RDAMs) respectively, of the proposed framework, as compared to 145 MWh in the aggregator-based retail energy delivery in the sequential structure. With increased penetration of DERs, there is significant reduction in energy

Table 6.3: Summary of DAM Clearing, Aggregated over 24-hours (Normal Operation)

Wholesale (WDAM)									
Methodology	Demand Cleared (MWh)	DR Cleared (MWh)	Gencos (MWh)	Wind (MWh)	Solar PV (MWh)	BESS Charging/ Discharging (MWh)	Network Losses (MWh)	CO_2-eq Emissions (kTonne)	Social Welfare (x1000 $)
Sequential*	73781	593	71140	2880	1095	182 / 96	2003	30.427	5628.374
4-DSOs, Parallel-Hierarchical	74311	603	71076	2880	1095	202 / 115	2025	30.372	5636.296
24-DSOs, Parallel-Hierarchical	74999	619	70996	2880	1095	188 / 100	2009	30.264	5640.111
Retail									
	Aggregator-based*		4-RDAMs	24-RDAMs		$RDAM_1$	$RDAM_9$	$RDAM_{18}$	$RDAM_{24}$
Power Injected by BTM-DERs (MWh)	145		769	1507		243	179	9	337

prices at the WDAM and RDAM, as was presented in Fig. 6.4, Fig. 6.5 and Fig. 6.6. Furthermore, it can be seen from Table 6.3 that there is an improvement in social welfare and a reduction in total emissions in the proposed framework as compared to the sequential structure; in both sub-cases of 4-DSOs and 24-DSOs (*with a note that only 16 DSOs out of 24 in SubCase-3 are cleared for injecting power into the WDAM*). The effect on social welfare and system emissions is larger with 24-DSOs (SubCase-3) as compared to 4-DSOs (SubCase-1). The DAM social welfare increased by $7,922 in SubCase-1 as compared to the sequential structure whereas, it improved by $11,737 in SubCase-3. Total system emissions over 24-hr decreased by 55 tonnes in SubCase-1 whereas, it reduced by 163 tonnes in SubCase-3.

6.6 Summary

This chapter presented a novel Cooperation Algorithm between the ISO and DSOs to facilitate increased penetration of DERs (including BTM-DERs) in the wholesale and retail electricity markets. Comprehensive and novel mathematical models were formulated to examine the system under study for day-ahead horizon at ISO and DSO levels (WDAM and RDAMs). The functionalities and effectiveness of the proposed framework were tested on the IEEE 24-bus RTS (for wholesale level) and multiple 33-bus distribution systems (for retail levels) by considering various case studies.

The proposed framework yielded increased clearance of BTM-DERs in the market settlements in comparison to the sequential structure, and alleviated the dependency of BTM-DERs on aggregators for their participation in the markets by enhancing the DSO role. It was seen that the LMPs decreased considerably using the proposed framework, under normal as well as during outage and congestion conditions in comparison to the sequential structure. The enhanced penetration of BTM-DERs in the market settlements resulted in increased social welfare and reduced system emissions. These impacts were higher with 24 DSOs participation as compared to 4 DSOs, with negligible effect on the computational burden. Thereby, it can be inferred that the proposed framework wherein the DERs' privacy is restricted to the DSO level, was scalable to large practical systems and was computationally faster than the centralized market settlement. Overall, it can be concluded that the proposed Cooperation Algorithm and the framework facilitated market entry of DERs (including BTM-DERs) by providing competitive and accessible electricity markets. The main contents of this chapter has been reported in a manuscript currently under review for publication in *IEEE Transactions on Energy Markets, Policy and Regulation*.

Chapter 7

Conclusions

7.1 Summary and Conclusions

In this thesis, the research presented demonstrate the role of hydrogen-based resources in electricity markets and inclusion of emission control strategies for accelerating NZE targets. The work presented here comprehensively examines the role of DR and BESS in an MSM framework considering the existing market rules, and their physical and operational characteristics; complying with FERC Order 745 and Order 841. This thesis also focuses on developing new and effective mechanisms and appropriate frameworks between ISO and DSOs to facilitate DERs participation in electricity markets in an equitable manner (in accordance with FERC Order 2222). The motivations, critical literature review and accordingly, the research objectives are discussed in Chapter 1.

In Chapter 2, the key background topics relevant to the research performed were covered. A general overview of electricity markets was presented, with a discussion on classification of markets based on levels, time-horizon and pricing schemes. Thereafter, the mathematical models were presented for LMP and UMP markets and different types of DR programs were discussed. An overview of ESTs was presented, with an elaborate description of their characteristics. The operational aspects and mathematical models for BESS and HSS were presented. Finally, the various coordination schemes between ISO and DSOs with their advantages and demerits was presented.

In Chapter 3, a new framework and a comprehensive mathematical model were proposed which integrated GHSs in an UMP-based day-ahead electricity market. The effect of considering two emission control strategies, namely emission cap and carbon pricing,

on electricity market settlements were investigated in detail. The effectiveness and performance of the model was evaluated by considering the IEEE 24-bus RTS and the supply mix of two real power systems with distinct characteristics, that of the Alberta and Ontario provinces of Canada. The model was comprehensively formulated to take into account the effect of carbon emissions, physical and operational characteristics of market participants.

Chapter 4 presented a comprehensive mathematical model of an HEFR-integrated, LMP-based, day-ahead electricity market. The model considered detailed physical, energy arbitrage and operational characteristics of the HEFRs. To examine the performance of the model, two cases were considered: without and with HEFRs, for normal, uncertainties and congestion scenarios.

In Chapter 5, a novel framework and comprehensive mathematical models were presented that included DR and BESS simultaneously in an LMP-based MSM (coordinated DAM and RTM - based on FERC's SMD structure) framework. The presented models examined their participation in energy-cum-SR co-optimized markets in DAM and energy-balancing in RTM. A novel methodology of incorporating generator day-ahead ramping requirements in the RTM settlement, based on their cleared DAM schedule, was developed using a set of new ramping constraints for generators, referred to as DALF Ramp. The models performance was tested by considering various case studies under different scenarios, uncertainty studies and sensitivity analyses.

Chapter 6 presented a new Cooperation Algorithm between the ISO and DSOs to facilitate increased penetration of DERs (including BTM-DERs) in the coupled wholesale and retail electricity markets. The proposed framework has a parallel-hierarchical topology contrary to the commonly considered sequential structure for wholesale-retail coupled markets. Comprehensive mathematical models at ISO and DSO levels (WDAM and RDAMs) were formulated to examine the system under study. The effectiveness and functionalities of the proposed framework were tested on the IEEE 24-bus RTS (for wholesale level) and multiple 33-bus distribution systems (for retail levels) by considering various case studies.

The following are the main conclusions from this thesis:

- In the base scenario of integrating GHSs in the DAM without any emission control strategy (Chapter 3), the GHSs were not cleared in the market settlement due to their expensive cost metrics. However, GHSs were cleared in each system (Alberta and Ontario) when emission control strategies were introduced. The consideration of carbon pricing and emission cap in the market model helped in reducing the system emissions although yielding higher MCPs and reduced social welfare as compared to the BAU case.

- The inclusion of GHSs helped in considerably smoothing during peak hours, the effect of inclusion of carbon pricing and emission cap on the MCPs. From the results, it was observed that the participation of GHSs improved the social welfare for all scenarios. It was observed from the studies that emission cap was the more effective strategy when the impact on social welfare and reduction in system emissions are considered; while carbon pricing was more effective when the impact on MCP was the determining attribute, in both Alberta and Ontario systems.

- From the sensitivity analyses, it was seen that as the emission cap was relaxed in the range 0.6 to 1 p.u for Alberta and 0.75 to 1 p.u. for Ontario, the social welfare increased while the GHS discharging to charging ratio decreased. When the SCC was increased in increments of 15 $/tonnes from year 2023 to 2035, the system emissions decreased while the *gross* social welfare increased, with more significant effect observed in Alberta as compared to Ontario. It was observed that when the carbon price was considered and varied from 55 $/tonnes to 80 $/tonnes in steps of 5 $/tonnes, the social welfare and system emissions both decreased, with more noticeable impact seen in Alberta as compared to Ontario.

- It was seen that the participation of HEFRs in the DAM (Chapter 4) yielded higher social welfare, reduced RES curtailment and lower system emissions. Their inclusion also resulted in lowering the LMP profiles in all three scenarios: normal operation, RES uncertainties and during line congestion. The outcomes of sensitivity analysis showed that social welfare increased and system emissions reduced with higher penetration of HEFRs.

- The simultaneous participation of DR and BESS in an MSM framework (Chapter 5) reduced the marginal prices for energy in the DAM as well as in the RTM, and SR prices in the DAM. It was observed that their simultaneous participation in co-optimized energy-cum-SR DAM yielded the highest social welfare. The RTM social welfare increased with the inclusion of the proposed DALF Ramp. From the sensitivity analyses, it was noted that the DAM and RTM social welfares increased with higher DR participation, with more significant increase during the high demand hours. It was further observed that the DAM and RTM social welfares decreased with increase in the initial SOC of BESS, with more significant decrease during the high demand hours.

- The system with DR and BESS hedged the RTM energy prices and enhanced the system flexibility during uncertain events such as line and generator outages, change in demand or RES generation, *etc.* in the dispatch stage. Results illustrate that

the DALF Ramp affected the RTM dispatch and aided in balancing the real-time deviations. The outcomes indicated that modeling of DR & BESS and including DALF Ramp helped in capturing their operational characteristics and in providing more flexible options to ISOs for scheduling the available energy resources in DAM and dispatching them in RTM during both normal and outage scenarios.

- The proposed ISO-DSO coordinated framework including the Cooperation Algorithm (Chapter 6) yielded increased clearance of BTM-DERs in the market settlements in comparison to the sequential structure. The proposed framework alleviated the dependency of BTM-DERs on aggregators for their participation in the markets.

- It was seen that the LMPs decreased considerably using the proposed ISO-DSO coordinated framework, under normal as well as during outage and congestion conditions in comparison to the sequential structure. The enhanced penetration of BTM-DERs in the market settlements resulted in increased social welfare and reduced system emissions. These impacts were higher with 24 DSOs participation as compared to 4 DSOs, with negligible effect on the computational effort. The proposed framework, wherein the DERs' privacy is restricted to the DSO level, was scalable to large practical systems and was computationally faster than the centralized market settlement. Overall, it can be concluded that the proposed Cooperation Algorithm and the framework facilitated market entry of DERs (including BTM-DERs) by providing competitive and accessible electricity markets.

7.2 Contributions

The main contributions of the presented research are the following:

- A generic framework has been proposed to integrate GHSs in the electricity markets including different emission control strategies, such as emission cap and carbon pricing, which assist in exploring their contributions in achieving an NZE grid.

- Comprehensive mathematical models to integrate GHSs in a UMP-based and an LMP-based DAM considering the physical, operational and energy arbitrage characteristics of GHS components (electrolyzers, storage tanks and fuel cells) have been formulated. The proposed models take into account the minimum size criteria as per FERC Order 2222 and energy arbitrage and market constraints inspired by FERC Order 841.

- The SMD guideline developed by FERC has been expanded in this thesis to include DR and BESS in an MSM framework to achieve a more resilient power grid. The proposed framework and mathematical models have been designed to comply with the essential requirements of FERC Order 745 and Order 841 for their participation in wholesale electricity markets. The proposed mathematical models include a novel DALF Ramp to provide realistic dispatch of generators in the RTM, and thus obtained more accurate market clearing decisions and operations. The inclusion of DALF Ramp aided in balancing the real-time fluctuations in a cost-effective way, using fewer resources.

- The thesis demonstrated that the simultaneous participation of DR and BESS in the DAM and RTM yielded many benefits as compared to their no/individual participation. The work encourages market participants to deploy DR and BESS, and assisting the system operators to address issues pertaining to flexibility and grid resiliency. The DALF Ramp and the LMP-based DR-BESS integrated MSM framework is envisaged to play a critical role in the electricity markets of the future, wherein market operators will be required to facilitate the entry of new technologies with more readiness to adapt to changing real-time conditions and variabilities.

- The thesis presents a novel parallel-hierarchical mechanism along side a *Cooperation Algorithm* for coordination between the ISO and multiple DSOs to facilitate market entry of small-scale DERs in a competitive and equitable manner, complying with the essential requirements of FERC Order 2222. The proposed framework is demonstrated to be scalable, computationally fast and requires minimal exchange of information between the ISO and DSOs.

- The proposed ISO-DSO coordination framework reduces the dependency on carbon-intensive resources and enhances the overall market efficiency and system operation by enabling BTM-DERs to participate in the energy markets to achieve lowered price profiles at the wholesale and retail levels.

The main contents of Chapter 3 have been published in [171,172] and of Chapter 4 have been published in [174]. The main contents of Chapter 5 have been published in [175,178]. The main contents of Chapter 6 has been reported in a manuscript currently under review for publication in *IEEE Transactions on Energy Markets, Policy and Regulation.*

7.3 Future Work

The following research ideas maybe pursued as future work:

- The proposed framework and models examined the integration of GHS in the DAM, which can be easily extended to the SMD by including the RTM. This would provide GHS owners another platform to provide their service and get compensated; overall encouraging more GHS deployments.
- The presented research investigated the role of GHS in the electric power sector only and that too without presence of any other emerging resources such as DR, BESSs and different ESTs. With the ambitious goal of achieving NZE eco-system, it is worthwhile to explore the role of GHS in the context of sector-coupling and in the system with various other emerging ESTs.
- System operation under uncertainties have been one of the main challenges encountered by the power system operators. The research work presented demonstrate the working of the model under uncertainties by carrying out MCS in day-ahead stage and some scenarios in real-time interval. To further examine the robustness of the proposed frameworks under real-time RES uncertainties, the frameworks can be extended to stochastic programming.
- The proposed ISO-DSO coordinated framework and market models could be easily extended to the SMD by including the RTM. This would assist in further defining the roles of ISO and DSOs at dispatch stage (close to real-time) and examine the impact on RTM settlement based on DAM schedules, DERs participation and coordination between the wholesale and retail levels.
- The proposed ISO-DSO coordinated framework for energy market could be extended to formulate the ISO-DSO ancillary market model in order to examine the role of DERs in providing different kinds of services in the ancillary market and investigating their participation impact.
- All the proposed frameworks can be explored to test on a larger real power systems to determine the challenges and complexities involved for such bigger power systems.

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APPENDICES

Appendix A

RES and GHS/HEFR Data

Table A.1: RES location

Bus	RES Type-Unit
1	Wind-1
2	Wind-2
7	Wind-3
9	Solar-1
19	Solar-2
20	Solar-3

Table A.2: Wind generation hourly variation [176, 177]

Hour	Multiply Factor (p.u.)
1	0.214552621
2	0.218054141
3	0.331763703
4	0.472017300
5	0.153601326
6	0.556192439
7	0.706323026
8	0.212972807
9	0.094172614
10	0.037108815
11	0.115491407
12	0.330872322
13	0.572325828
14	0.372063338
15	0.637281114
16	0.610741714
17	0.619790304
18	0.551287044
19	0.461287780
20	0.329950798
21	0.099952577
22	0.247921786
23	0.088490928
24	0.192349258

Table A.3: Solar generation hourly variation [176, 177]

Hour	Multiply Factor (p.u.)
1	0.0000236745
2	0.0001112840
3	0.0000435638
4	0.0000836866
5	0.0000885730
6	0.0001300030
7	0.0001353030
8	0.0000837555
9	0.0111964580
10	0.0752991880
11	0.3305413380
12	0.4506979000
13	0.3398631560
14	0.4621347470
15	0.4308340730
16	0.6102880170
17	0.5008895030
18	0.2181220370
19	0.1722965790
20	0.0469853040
21	0.0003920740
22	0.0000584981
23	0.0001128670
24	0.0001192670

Table A.4: RES and GHS data [152]

$C^{RES_{wg}}$ ($/MWh)	$C^{RES_{pv}}$ ($/MWh)	$C^{GHS_{ch}}$ ($/MWh)	$C^{GHS_{Dch}}$ ($/MWh)	C^{Emm} ($/tonnes)	$\eta^{GHS_{ch/Dch}}$ (%)	LHV^{GHS} (MWh/mol)	$\Re$ (J/K-mol)
30	20	90	90	65	68/60	0.0000333	8.31446261815324

Table A.5: GHS electrolyzer and fuel cell data

	Electrolyzer			Fuel Cell		
GHS Unit	Pmax (MW)	Pmin (MW)	Nmax (x10^3 mol)	Pmax (MW)	Pmin (MW)	Nmax (x10^3 mol)
1	16	0.8	400	16	1.6	1008
2	20	1	500	20	2	1260
3	24	1.2	600	24	2.4	1512
4	28	1.4	700	28	2.8	1764
5	32	1.6	800	32	3.2	2016
6	36	1.8	900	36	3.6	2268
7	40	2	1000	40	4	2520
8	44	2.2	1100	44	4.4	2772
9	48	2.4	1200	48	4.8	3024
10	52	2.6	1300	52	5.2	3276

Table A.6: GHS storage tank data

GHS Unit	Prmax (MPa)	Prmin (MPa)	Prini (MPa)	Vol (m^3)	Temp. (K)	SOCmax (x10^3 mol)	SOCmin (x10^3 mol)	SOCini (x10^3 mol)
1	80	8	70	25	373.15	400	40	160
2	80	8	70	31.25	383.15	500	50	200
3	80	8	70	37.5	393.15	600	60	240
4	80	8	70	43.75	403.15	700	70	280
5	80	8	70	50	413.15	800	80	320
6	80	8	70	56.25	423.15	900	90	360
7	80	8	70	62.5	433.15	1000	100	400
8	80	8	70	68.75	443.15	1100	110	440
9	80	8	70	75	453.15	1200	120	480
10	80	8	70	81.25	423.15	1300	130	520

Table A.7: GHS units location

Bus	GHS Unit
4	1
4	2
5	3
5	4
9	5
9	6
19	7
19	8
20	9
20	10

Appendix B

IEEE 24-Bus Reliability Test System (RTS) and 33-Bus Distribution System Data

Table B.1: Generator Min./Max. Up/Down time and reliability data [17]

Unit Group	Unit Size	Unit Type	Forced Outage Rate	Min. Down Time (hr)	Min. Up Time (hr)	Ramp Rate (MW/min)
U12	12	Oil/Steam	0.02	2	4	2
U20	20	Oil/CT	0.1	1	1	3
U50	50	Hydro	0.01	N/A		
U76	76	Coal/Steam	0.02	4	8	2
U100	100	Oil/Steam	0.04	8	8	7
U155	155	Coal/Steam	0.04	8	8	3
U197	197	Nuclear	0.05	10	12	20
U350	350	Coal/Steam	0.08	48	24	4
U400	400	Nuclear	0.12	1	1	20

Table B.2: Bus load data [17]

Bus	Load (MW)
1	108
2	97
3	180
4	74
5	71
6	136
7	125
8	171
9	175
10	195
13	265
14	194
15	317
16	100
18	333
19	181
20	128
Total	2850

Table B.3: Hourly peak load in percent of daily peak [17]

Hour	Hourly Load (%)
12:00 - 1:00 AM	78
1:00 - 2:00 AM	72
2:00 - 3:00 AM	68
3:00 - 4:00 AM	66
4:00 - 5:00 AM	64
5:00 - 6: 00 AM	65
6:00 - 7:00 AM	66
7:00 - 8:00 AM	70
8:00 - 9:00 AM	80
9:00 - 10:00 AM	88
10:00 - 11:00 AM	90
11:00 - Noon	91
Noon - 1:00 PM	90
1:00 - 2:00 PM	88
2:00 - 3:00 PM	87
3:00 - 4:00 PM	91
4:00 - 5:00 PM	100
5:00 - 6:00 PM	99
6:00 - 7:00 PM	97
7:00 - 8:00 PM	95
8:00 - 9:00 PM	94
9:00 - 10:00 PM	92
10:00 - 11:00 PM	87
11:00 - 12:00 AM	81

Table B.4: Transmission line length, impedance and rating data [17]

Line Number	From Bus	To Bus	Length (mile)	Impedance p.u./100 MVA Base			Rating (MVA)
				R	X	B	
1	1	2	3	0.003	0.014	0.461	175
2	1	3	55	0.055	0.211	0.057	175
3	1	5	22	0.022	0.085	0.023	175
4	2	4	33	0.033	0.127	0.034	175
5	2	6	50	0.05	0.192	0.052	175
6	3	9	31	0.031	0.119	0.032	175
7	3	24	0	0.002	0.084	0	400
8	4	9	27	0.027	0.104	0.028	175
9	5	10	23	0.023	0.088	0.024	175
10	6	10	16	0.014	0.061	2.459	175
11	7	8	16	0.016	0.061	0.017	175
12	8	9	43	0.042	0.161	0.044	175
13	8	10	43	0.043	0.165	0.045	175
14	9	11	0	0.043	0.165	0.045	175
15	9	12	0	0.002	0.084	0	400
16	10	11	0	0.002	0.084	0	400
17	10	12	0	0.002	0.084	0	400
18	11	13	33	0.006	0.048	0.1	500
19	11	14	29	0.005	0.042	0.088	500
20	12	13	33	0.006	0.048	0.1	500

Table B.5: Transmission line length, impedance and rating data [17]

Line Number	From Bus	To Bus	Length (mile)	Impedance p.u./100 MVA Base			Rating (MVA)
				R	X	B	
21	12	23	67	0.012	0.097	0.203	500
22	13	23	60	0.011	0.087	0.182	500
23	14	16	27	0.005	0.059	0.082	500
24	15	16	12	0.002	0.017	0.036	500
25	15	21	34	0.006	0.049	0.103	500
26	15	21	34	0.006	0.049	0.103	500
27	15	24	36	0.007	0.052	0.109	500
28	16	17	18	0.003	0.026	0.055	500
29	16	19	16	0.003	0.023	0.049	500
30	17	18	10	0.002	0.014	0.03	500
31	17	22	73	0.014	0.105	0.221	500
32	18	21	18	0.003	0.026	0.055	500
33	18	21	18	0.003	0.026	0.055	500
34	19	20	27.5	0.005	0.04	0.083	500
35	19	20	27.5	0.005	0.04	0.083	500
36	20	23	15	0.003	0.022	0.046	500
37	20	23	15	0.003	0.022	0.046	500
38	21	22	47	0.009	0.068	0.142	500

Table B.6: Generating unit location and capability [17]

Bus	Gen. Number	Unit Group
1	1	U20
1	2	U20
1	3	U76
1	4	U76
2	5	U20
2	6	U20
2	7	U76
2	8	U76
7	9	U100
7	10	U100
7	11	U100
13	12	U197
13	13	U197
13	14	U197
15	15	U12
15	16	U12
15	17	U12
15	18	U12
15	19	U12
15	20	U155
16	21	U155
18	22	U400
21	23	U400
22	24	U50
22	25	U50
22	26	U50
22	27	U50
22	28	U50
22	29	U50
23	30	U155
23	31	U155
23	32	U350

Table B.7: Data for 33-Bus system: Feeder parameters [180]

Line i-j	R (ohms)	X (ohms)	Charging (p.u.)
Main Branch			
1.2	0.0922	0.0477	0.0052
2.3	0.4930	0.2511	0.0277
3.4	0.3660	0.1864	0.0206
4.5	0.3811	0.1941	0.0214
5.6	0.8190	0.7070	0.0460
6.7	0.1872	0.6188	0.0103
7.8	0.7114	0.2351	0.0961
8.9	1.0300	0.7400	0.0578
9.10	1.0440	0.7400	0.0586
10.11	0.1966	0.0650	0.0110
11.12	0.3744	0.1238	0.0210
12.13	1.4680	1.1550	0.0824
13.14	0.5416	0.7129	0.0304
14.15	0.5910	0.5260	0.0332
15.16	0.7463	0.5450	0.0419
16.17	1.2890	1.7210	0.0724
17.18	0.7320	0.5740	0.0411
Left Branch			
2.19	0.1640	0.1565	0.0092
19.20	1.5042	1.3554	0.0845
20.21	0.4095	0.4784	0.0244
21.22	0.7089	0.9373	0.0398
Right Branch			
3.23	0.4512	0.3083	0.0253
23.24	0.8980	0.7091	0.0504
24.25	0.8960	0.7011	0.0503
6.26	0.2030	0.1034	0.0114
26.27	0.2842	0.1447	0.0160
27.28	1.0590	0.9337	0.0595
28.29	0.8042	0.7006	0.0452
29.30	0.5075	0.2585	0.0285
30.31	0.9744	0.9630	0.0547
31.32	0.3105	0.3619	0.0262
32.33	0.3410	0.5302	0.0191

Table B.8: Data for 33-Bus system: Load [180]

Bus i	P (kW)	Q (kvar)
2	100	60
3	90	40
4	120	80
5	60	30
6	60	20
7	200	100
8	200	100
9	60	20
10	60	20
11	45	30
12	60	35
13	60	35
14	120	80
15	60	10
16	60	20
17	60	20
18	90	40
19	90	40
20	90	40
21	90	40
22	90	40
23	90	50
24	420	200
25	420	200
26	60	25
27	60	25
28	60	20
29	120	70
30	200	600
31	150	70
32	210	100
33	60	40

Appendix C

Generator, DR and BESS Data

Table C.1: Generator energy offers [17]

		Generator - Energy Offers					
Gen. Size	Gen. Type	Block 1		Block 2		Block 3	
		Quantity	Price	Quantity	Price	Quantity	Price
12 MW	Oil/Steam	5	45.68	6	52.73	1	55.54
20 MW	Oil/CT	5	56.41	10	105.12	5	129.47
76 MW	Coal/Steam	25	12	40	15.15	11	16.02
100 MW	Oil/Steam	35	37.14	35	41.92	10	44.05
155 MW	Coal/Steam	50	10.33	80	11.47	25	11.82
197 MW	Oil/Steam	60	36.68	100	41.1	37	42.74
350 MW	Coal/Steam	120	10.49	175	12	55	12.42
400 MW	Nuclear	150	5.76	200	6	50	6.06

Note: All bid/offer quantities are in MW, energy prices are in $/MWh.

Table C.2: Generator spinning reserve offers [17]

		Generator - Spinning Reserve Offers					
Gen. Size	Gen. Type	Block 1		Block 2		Block 3	
		Quantity	Price	Quantity	Price	Quantity	Price
12 MW	Oil/Steam	1	18.27	1	21.09	0.01	22.22
20 MW	Oil/CT	1	22.56	2	42.05	1	51.79
76 MW	Coal/Steam	5	4.80	7	6.06	2	6.41
100 MW	Oil/Steam	7	14.86	9	16.77	4	17.62
155 MW	Coal/Steam	10	4.13	15	4.59	6	4.73
197 MW	Oil/Steam	12	14.67	20	16.44	8	17.10
350 MW	Coal/Steam	24	4.20	36	4.80	10	4.97
400 MW	Nuclear	30	2.30	40	2.40	10	2.42

Note: All bid/offer quantities are in MW, spinning reserve prices are in $/MW.

Table C.3: Demand energy bids (for hour-18) [17]

	Demand Bids					
Bus	Block 1		Block 2		Block 3	
	Quantity	Price	Quantity	Price	Quantity	Price
1	75.6	100	21.6	80.6	108	70.4
2	67.9	100	19.4	904	9.7	85.9
3	126	100	36	722	18	67.1
4	51.8	100	14.8	86.7	7.4	73.5
5	49.7	100	14.2	70.7	7.1	68.5
6	95.2	100	27.2	80.3	13.6	74.6
7	87.5	100	25	96.7	125	90.4
8	119.7	100	34.2	733	17.1	67.8
9	122.5	100	35	722	17.5	62.2
10	136.5	100	39	83.5	195	58.5
13	185.5	100	53.0	76.5	265	56
14	135.8	100	38.8	81.3	19.4	67.5
15	221.9	100	63.4	74.6	31.7	60.1
16	70	100	20	79.8	10	74.1
18	233.1	100	66.6	90.7	33.3	86.3
19	126.7	100	36.2	91.0	18.1	88.1
20	89.6	100	25.6	80.6	128	84.2

Note: All bid/offer quantities are in MW, energy prices are in $/MWh.

Table C.4: DR energy offers (for hour-18) [17]

	DRE - Offers					
Bus	Block 1		Block 2		Block 3	
	Quantity	Price	Quantity	Price	Quantity	Price
1	0.54	110	1.08	84.7	3.78	53.9
2	0.5	110	1	94.9	3.4	90.2
3	0.9	110	1.8	75.8	6.3	70.4
4	0.4	110	0.7	91.1	2.6	57.1
5	0.4	110	0.7	74.2	2.5	72
6	0.7	110	1.4	84.3	48	58.4
7	0.6	110	1.3	1005	44	95
8	0.9	110	1.7	76.9	6	71.2
9	0.9	110	1.8	72.6	6.1	55.3
10	1	110	2	86.7	6.8	57.4
13	1.3	110	2.7	78	9.3	56.8
14	1	110	1.9	78.3	6.8	57.4
15	1.6	110	3.2	76.9	11.1	63.1
16	0.5	110	1	83.8	3.5	57.8
18	1.7	110	3.3	1005	11.7	90.6
19	0.9	110	1.8	90.6	6.3	92.5
20	0.6	110	1.3	94.0	4.5	88.4

Note: All bid/offer quantities are in MW, energy prices are in $/MWh.

Table C.5: DR spinning reserve offers (for hour-18) [17]

	DRSR - Offers					
Bus	Block 1		Block 2		Block 3	
	Quantity	Price	Quantity	Price	Quantity	Price
1	0.54	44	1.08	33.9	3.78	21.6
2	0.5	44	1	38	34	36.1
3	0.9	44	1.8	30.3	6.3	28.2
4	0.4	44	0.7	364	2.6	22.9
5	0.4	44	0.7	29.7	2.5	28.8
6	0.7	44	1.4	33.7	48	23.3
7	0.6	44	1.3	40.2	44	38
8	0.9	44	1.7	30.8	6	28.5
9	0.9	44	1.8	29	6.1	22.1
10	1	44	2	34.7	6.8	23
13	1.3	44	2.7	31.2	9.3	22.7
14	1	44	1.9	31.3	6.8	23
15	1.6	44	3.2	30.3	11.1	25.3
16	1	44	1	33.5	3.5	23.1
18	1.7	44	3.3	40.2	11.7	36.2
19	0.9	44	1.8	38.2	6.3	37
20	0.6	44	1.3	37.6	45	35.4

Note: All bid/offer quantities are in MW, spinning reserve prices are in $/MW.

Table C.6: BESS data [17]

BESS Unit	$\underline{E}$ (MWh)	$\overline{E}$ (MWh)	SOC_0 (p.u.)	$\overline{P}^{ch/Dch}$ (MW)	$\eta^{ch/Dch}$ (p.u.)	D^{max} (p.u.)	a ($/MWh)	b ($/MWh)	c ($)	d ($)	C2 ($)
1	3	15	0.4	25	0.95	1	-36.23	34.80	2.77	-3.45	18
2	3	15	0.5	25	0.95	1	-36.23	34.80	2.77	-3.45	18
3	6	30	0.7	15	0.95	1	-36.23	34.80	2.77	-2.90	12
4	6	30	0.7	15	0.95	1	-36.23	34.80	2.77	-2.90	12
5	10	50	0.3	20	0.95	1	-36.23	34.80	2.77	-2.45	8
6	10	50	0.3	20	0.95	1	-36.23	34.80	2.77	-2.45	8
7	2	12.5	0.75	20	0.95	1	-36.23	34.80	2.77	-3.75	15
8	2	12.5	0.75	20	0.95	1	-36.23	34.80	2.77	-3.75	15
9	2	12.5	0.5	20	0.95	1	-36.23	34.80	2.77	-3.75	15
10	2	12.5	0.5	20	0.95	1	-36.23	34.80	2.77	-3.75	15

Table C.7: BESS location

Bus	BESS Unit
4	1
4	2
5	3
5	4
9	5
9	6
19	7
19	8
20	9
20	10