Report on Short-Term Power Market in India: 2021-22

के वि वि आयोग
CERC

Economics Division
Central Electricity Regulatory Commission

Report on
Short-Term Power Market in India
2021-22

के वि वि आयोग
CERC

CENTRAL ELECTRICITY REGULATORY COMMISSION

3rd & 4th Floor, Chanderlok Building
36, Janpath, New Delhi-110001
Phone: +91-11-23353503, Fax: +91-11-23753923
www.cercind.gov.in

Contents

S.No.	Particulars	Page No.
	Contents	i
	List of Tables	iii
	List of Figures	vi
	Preface	ix
	Abbreviations	xi
	Executive Summary	xvi
	Chapter-I: Overview of Power Sector	
1	**Generation**	1
2	**Transmission**	7
3	**Distribution**	9
	Chapter-II: Short-term Power Market in India	
1	**Introduction**	15
2	**Yearly Trends in Short-term Transactions of Electricity (2009-10 to 2021-22)**	18
2.1	Total Short-term Transactions of Electricity with respect to Total Electricity Generation	18
2.1.1	*Electricity Transacted through Traders and Power Exchanges*	19
2.1.2	*Electricity Transacted through DSM*	24
2.1.3	*Electricity Transacted Directly between DISCOMs*	26
3	**Monthly Trends in Short-term Transactions of Electricity (April 2021-March 2022)**	27
3.1	Volume of Short-term Transactions of Electricity	28
3.2	Price of Short-term Transactions of Electricity	32
3.3	Volume of Electricity Transacted in various Price Slabs	33
4	**Daily Trends in Short-term Transactions of Electricity (1st April 2021 to 31st March 2022)**	38
4.1	Volume of Short-term Transactions of Electricity	38
4.2	Price of Short-term Transactions of Electricity	38
4.2.1	*Price and its volatility in Power Exchanges*	38
4.2.2	*Price and its volatility in DSM*	40

S.No.	Particulars	Page No.
5	**Time of the Day Variation in Volume and Price of Electricity Transacted through Traders and Power Exchanges**	41
5.1	Time of the Day Variation in Volume and Price of Electricity Transacted through Traders	41
5.2	Time of the Day Variation in Volume and Price of Electricity Transacted through Power Exchanges	42
6	**Trading Margin Charged by Trading Licensees**	46
7	**Open Access Consumers on Power Exchanges**	48
7.1	Types of Participants in Power Exchanges	48
7.2	Analysis of Open Access Consumers on Power Exchanges	50
8	**Major Sellers and Buyers of Electricity in the Short-term market**	54
9	**Effect of Congestion on the Volume of Electricity Transacted through Power Exchanges**	60
10	**Ancillary Services Operations**	63
10.1	Background	63
10.2	Regulatory Framework of Ancillary Services	64
10.3	RRAS Instructions issued by Nodal Agency	67
10.4	RRAS Accounting and Settlement	68
	Chapter-III: Cross Border Trade of Electricity	
1	**Background**	70
2	**Cross Border Trade of Electricity between India and its Neighbouring Countries**	71
3.	**Cross Border Trade through Power Exchange**	72
	Chapter-IV: Tariff of Long-term Sources of Power	
1	**Background**	73
2	**Guidelines and Standard Bidding Documents (SBDs) for Procurement of Electricity by Distribution Licensees through Tariff based Bidding Process**	73
3	**Tariff of Central Public Sector Power Generating companies**	75
	Chapter-V: Trading of Renewable Energy Certificates	
1	**Renewable Energy Certificate Mechanism**	80
2	**Trading of Renewable Energy Certificates**	81
	Annexure-I: List of Transmission Licensees as on 31.03.2022	87
	Annexure-II: List of Trading Licensee as on 31.03.2022	89
	Annexure-III: Historical Volatility Formula	91
	Annexure-IV: Herfindahl-Hirschman Index	92

List of Tables

Table No.	Details	Page No.
Table-1	Installed Electricity Generation Capacity in India (GW), 2008-09 to 2021-22	1
Table-2	Sector-wise Growth of Installed Electricity Generation Capacity, 2008-09 to 2021-22	3
Table-3	Gross Electricity Generation in India (BU), 2008-09 to 2021-22	4
Table-4	Power Supply Position in India, 2008-09 to 2021-22	6
Table-5	Growth of Transmission System in India, 2008-09 to 2021-22	7
Table-6	Annual Transmission Charges, 2011-12 to 2021-22	8
Table-7	Growth of Electricity Consumption in India (Consumer category-wise) (BU), 2008-09 to 2020-21	10
Table-8	Average Cost of Supply and Average Revenue of State Power Utilities, 2008-09 to 2020-21	12
Table-9	Volume of Short-term Transactions of Electricity with respect to Total Electricity Generation, 2009-10 to 2021-22	19
Table-10(a)	Volume of Electricity Transacted through Traders and Power Exchanges (BU), 2008-09 to 2021-22	20
Table-10(b)	Volume of Electricity Transacted through Power Exchanges (BU), 2008-09 to 2021-22	20
Table-11	Electricity Transacted through Traders and Power Exchanges as % of Total Short-Term Transactions, 2009-10 to 2021-22	22
Table-12	Price of Electricity Transacted through Traders and Power Exchanges, 2008-09 to 2021-22	23
Table-13	Volume of Electricity Transacted through Traders and Power Exchanges (BU), 2009-10 to 2021-22	24
Table-14	Volume and Price of Electricity Transacted through DSM, 2009-10 to 2021-22	25
Table-15	Volume of Electricity Transacted Directly between DISCOMs	26
Table-16	Volume of Short-term Transactions of Electricity (BU), 2021-22	28
Table-17	Volume of Short-term Transactions of Electricity as % of Total	29

Table No.	Details	Page No.
	Electricity Generation, 2021-22	
Table-18	Share of Electricity Transacted by Traders and HHI, 2021-22	30
Table-19(a)	Price of Short-term Transactions of Electricity (₹/kWh), 2021-22	32
Table-19(b)	Price of Power Exchange Transactions of Electricity (₹/kWh), 2021-22	34
Table-20	Trading Margin Charged by Trading Licensees, 2009-10 to 2021-22	47
Table-21	Number of Open Access Consumers in Power Exchanges, 2010-11 to 2021-22	50
Table-22(a)	Volume of Purchase by Open Access Consumers in Day Ahead Market of Power Exchanges, 2010-11 to 2021-22	52
Table-22(b)	Volume of Purchase by Open Access Consumers in Green Day Ahead Market of Power Exchanges, 2021-22	53
Table-22(c)	Volume of Purchase by Open Access Consumers in Real Time Market of Power Exchanges, 2020-21 to 2021-22	53
Table-23	Major Sellers of Electricity through Traders, 2021-22	54
Table-24	Major Buyers of Electricity through Traders, 2021-22	55
Table-25(a)	Major Sellers of Electricity in Day Ahead Market of IEX, 2021-22	55
Table-25(b)	Major Sellers of Electricity in Green Day Ahead Market of IEX, 2021-22	56
Table-25(c)	Major Sellers of Electricity in Real Time Market of IEX, 2021-22	56
Table-26(a)	Major Buyers of Electricity in Day Ahead Market of IEX, 2021-22	57
Table-26(b)	Major Buyer of Electricity in Green Day Ahead Market of IEX, 2021-22	57
Table-26(c)	Major Buyer of Electricity in Real Time Market of IEX, 2021-22	58
Table-27	Major Sellers of Electricity in Day Ahead Market of PXIL,	59

Table No.	Details	Page No.
	2021-22	
Table-28	Major Buyers of Electricity in Day Ahead Market of PXIL, 2021-22	59
Table-29	Effect of Congestion on the Volume of Electricity Transacted through Power Exchanges, 2009-10 to 2021-22	61
Table-30	Details of Congestion in Power Exchanges, 2021-22	62
Table-31	Congestion Charges of Power Exchanges, 2008-09- to 2021-22	62
Table-32	Maximum Ancillary despatched in a Time Block (MW), 2021-22	67
Table-33	Energy Scheduled and Payments made for Ancillary Services, 2016-17 to 2021-22	68
Table-34	Cross Border Trade of Electricity between India and its Neighbouring Countries, 2013-14 to 2021-22 (BU)	71
Table-35	Month-wise Cross Border Trade of Electricity at IEX, 2021-22	72
Table-36	Tariff of Central Thermal Power Stations, 2021-22	76
Table-37	Composite Tariff of Central Hydro Power Stations, 2021-22	78
Table-38	Floor and Forbearance Price applicable for REC Transactions	81
Table-39	Growth of RECs transacted on Power Exchanges, 2011-12 to 2021-22	82
Table-40	Demand and Supply of RECs on Power Exchanges, 2012-13 to 2021-22	83
Table-41	Volume and Price of RECs transacted on Power Exchanges, 2012-13 to 2021-22	84
Table-42	Long-term Growth Trajectory of RPOs	86

List of Figures

Figure No.	Details	Page No.
Figure-1	Installed Electricity Generation Capacity in India (%), 2008-09 to 2021-22	2
Figure-2	Sector-wise Growth of Installed Electricity Generation Capacity (%), 2008-09 to 2021-22	4
Figure-3	Gross Electricity Generation in India (%), 2008-09 to 2021-22	5
Figure-4	Energy Deficit and Peak Deficit in India, 2008-09 to 2021-22	6
Figure-5	Growth of Transmission System in India, 2008-09 to 2021-22	8
Figure-6	Growth of Electricity Consumption in India (Consumer category-wise), 2008-09 to 2020-21	11
Figure-7	Average Cost of Supply and Average Revenue of State Power Utilities, 2008-09 to 2020-21	12
Figure-8	Volume of Electricity Transacted through Traders & Power Exchanges, 2008-09 to 2021-22	21
Figure-9	Price of Electricity Transacted through Traders and Power Exchanges, 2008-09 to 2021-22	23
Figure-10	Volume and Price of Electricity transacted through DSM, 2009-10 to 2021-22	25
Figure-11	Volume of Electricity Transacted Directly between DISCOMs, 2009-10 to 2021-22	26
Figure-12	Share of Market Segments in Total Electricity Generation, 2021-22	27
Figure-13	Share of Market Segments in Short-Term Transactions, 2021-22	27
Figure-14	Volume of Short-term Transactions of Electricity, 2021-22	29
Figure-15	Share of Electricity transacted by Traders, 2021-22	31
Figure-16	Concentration of Market Power in Bilateral Transactions through Traders, 2008-09 to 2021-22	32
Figure-17	Comparison of Price of Bilateral, Power Exchange and DSM Transactions, 2021-22	33
Figure-18(a)	Price of Electricity Transacted through Traders during Round	34

Figure No.	Details	Page No.
	the Clock, Peak and Off Peak periods, 2021-22	
Figure-18(b)	Price of Electricity Transacted through Power Exchanges in different market segments 2021-22	35
Figure-19	Volume of Bilateral Transaction at different Price Slabs, 2021-22	35
Figure-20(a)	Volume of IEX Transactions in Day Ahead Market at different Price Slabs, 2021-22	36
Figure-20(b)	Volume of IEX Transactions in Green Day Ahead Market at different Price Slabs, 2021-22	36
Figure-20(c)	Volume of IEX Transactions in Real Time Market at different Price Slabs, 2021-22	37
Figure-21	Volume of PXIL Transactions in Day Ahead Market at different Price Slabs, 2021-22	37
Figure-22	Volume of Short-term Transactions of Electricity, 2021-22	38
Figure-23(a)	Price and its Volatility in DAM on IEX during 2021-22	39
Figure-23(b)	Price and its Volatility in G-DAM on IEX during 2021-22	39
Figure-23(c)	Price and its Volatility in RTM on IEX during 2021-22	39
Figure-24	Price and its Volatility in DAM on PXIL during 2021-22	40
Figure-25	Price and its Volatility in DSM during 2021-22	41
Figure-26	Volume and Price of Electricity Transacted through Traders during RTC, Peak and OTP, 2021-22	42
Figure-27(a)	Block-wise Market Clearing Volume and Price in DAM on IEX during 2021-22	43
Figure-27(b)	Block-wise Market Clearing Volume and Price in G-DAM on IEX during 2021-22	43
Figure-27(c)	Block-wise Market Clearing Volume and Price in RTM on IEX during 2021-22	43
Figure-28	Block-wise Market Clearing Volume and Price in DAM on PXIL during 2021-22	44
Figure-29(a)	Region-wise and Block-wise Price of Electricity Transacted in DAM through IEX, 2021-22	44
Figure-29(b)	Region-wise and Block-wise Price of Electricity Transacted	45

Figure No.	Details	Page No.
	in GDAM through IEX, 2021-22	
Figure-29(c)	Region-wise and Block-wise Price of Electricity Transacted in RTM through IEX, 2021-22	45
Figure-30	Region-wise and Block-wise Price of Electricity Transacted in DAM through PXIL, 2021-22	45
Figure-31	Trading Margin Charged by Trading Licensees, 2009-10 to 2021-22	47
Figure-32(a)	Sell and Buy Volume of various types of Participants in DAM on IEX, 2021-22	48
Figure-32(b)	Sell and Buy Volume of various types of Participants in GDAM on IEX, 2021-22	49
Figure-32(c)	Sell and Buy Volume of various types of Participants in RTM on IEX, 2021-22	49
Figure-33	Sell and Buy Volume of various types of Participants in DAM on PXIL, 2021-22	49
Figure-34	State-wise Number of Open Access Consumers in IEX, March 2022	51
Figure-35	State-wise Number of Open Access Consumers in PXIL, March 2022	51
Figure-36	Energy scheduled to/from Virtual Ancillary Entity under RRAS (MU), 2021-22	69

Preface

The Electricity Act, 2003 consolidates the laws relating to generation, transmission, distribution, trading, and use of electricity and generally for taking measures conducive to development of electricity industry, promoting competition therein, protecting interest of consumers and supply of electricity to all areas, rationalization of electricity tariff, ensuring transparent policies, etc. This is further strengthened by the regulatory initiatives of the Electricity Regulatory Commissions through various regulations and orders required to enable a framework for a robust and healthy power market in the country.

The Central Electricity Regulatory Commission sets the regulatory process in motion through Trading License Regulations, Open Access Regulations, Power Market Regulations, and Deviation Settlement Mechanism Regulations. Under these regulations, short-term power market covers contracts of less than a year for electricity transacted through Inter-State Trading Licensees and directly by the Distribution Licensees, Power Exchanges, and Deviation Settlement Mechanism. The short-term power market as an integral part of the power sector has been beneficial for meeting the short-term needs of the consumers, suppliers, and the sector as a whole. It constitutes about 12.5 per cent of the total electricity generation in India in the year 2021-22.

The annual report on short-term power market in India provides a snapshot of short-term transactions of electricity through different instruments used by various market participants. The Central Electricity Regulatory Commission brings out this report with the objective to keep market participants and other stakeholders aware and updated on the state of the power market in the country. The dissemination of information through the report is one of the key elements to ensure efficiency and competition in the sector and for stakeholders and consumers to maintain faith in the system. This report covers overview of power sector, trends in short-term transactions of electricity on annual, monthly, and daily basis, time of the day variation in volume and price of electricity, trading margin for bilateral transactions, analysis of transactions carried out by various types of participants with emphasis on open access consumers on power exchanges, effect of congestion on volume of electricity traded on power exchanges, and ancillary services operations. The report also covers cross border trade of electricity between India and its neighbouring countries, tariff of long-term sources of power and analysis on transactions of Renewable Energy Certificates.

In order to ensure ease of access, this report is also made available on the CERC website www.cercind.gov.in. We are hopeful that market participants and stakeholders will find the Report on Short-term Power Market in India 2021-22 useful.

***

Abbreviations

Abbreviation	Expanded Version
AC	Alternating Current
ACE	Area Control Error
ACS	Average Cost of Supply
AGC	Automatic Generation Control
APCPDCL	Andhra Pradesh Central Power Distribution Company Limited
APDCL	Assam Power Distribution Company Ltd
APL	Above Poverty Line
APPCC	Andhra Pradesh Power Coordination Committee
APSPDCL	Andhra Pradesh Southern Power Distribution Company Limited
APTEL	Appellate Tribunal for Electricity
ARR	Average Revenue Realized
AT&C	Aggregate Technical and Commercial
Block	15 Minutes Time Block
BSPHCL	Bihar State Power Holding Company Limited
BU	Billion Units (Billion kWh)
CAGR	Compound Annual Growth Rate
CBTE	Cross Border Trade of Electricity
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CESC	Calcutta Electric Supply Corporation
CGS	Central Generating Station
CGSEB	Chhattisgarh State Electricity Board
Ckm	Circuit km
COP	Conference of the Parties
CPP	Captive Power Producer/Plant
CSPDCL	Chhattisgarh State Power Distribution Company Limited
CTU	Central Transmission Utility
DAM	Day Ahead Market
DBFOO	Design, Build, Finance, Own and Operate
DBFOT	Design, Build, Finance, Operate and Transfer
DDUGJY	Deendayal Upadhyaya Gram Jyoti Yojana

Abbreviation	Expanded Version
DISCOMs	Distribution Companies
DNHDDPDCL	Dadra and Nagar Haveli and Daman and Diu Power Distribution Corporation Limited
DSM	Deviation Settlement Mechanism
DVC	Damodar Valley Corporation
EDCL	Energy development Company Limited
EGoM	Empowered Group of Ministers
ER	Eastern Region
ERSS	Eastern Region Strengthening Scheme
FCAS	Frequency Control Ancillary Services
FGUTPS	Firoz Gandhi Unchahar Thermal Power Station
FRAS	Fast Response Ancillary Services
G-DAC	Green Day Ahead Contract
G-DAM	Green Day Ahead Market
GOHP/GoHP	Government of Himachal Pradesh
GPS	Gas Power Station
GRIDCO	GRIDCO Limited
G-TAM	Green Term Ahead Market
GUVNL	Gujarat Urja Vikas Nigam Limited
GW	Giga Watts
HEP	Hydro Electric Project
HHI	Herfindahl-Hirschman Index
HP	Himachal Pradesh
HPO	Hydro Purchase Obligation
HPP	Hydroelectric Power Plant
HPPC	Haryana Power Purchase Centre
HPSEB	Himachal Pradesh State Electricity Board
HVDC	High-Voltage Direct Current
IDAM	Integrated Day Ahead Market
IEGC	Indian Electricity Grid Code
IEX	Indian Energy Exchange
IPDS	Integrated Power Development Scheme
IPP	Independent Power Producers
ISGS	Inter State Generating Station
ISTS	Inter State Transmission System
JBVNL	Jharkhand Bijli Vitran Nigam Limited

Abbreviation	Expanded Version
J&K PDD	Jammu & Kashmir Power Development Department
JKPCL	Jammu Kashmir Power Corporation Ltd.
JVVNL	Jaipur Vidyut Vitaran Nigam Ltd.
KSEB	Kerala State Electricity Board
KV	Kilovolt
kWh	Kilo Watt Hour
LDP	Low Dam Project
LTA	Long Term Access
Ltd.	Limited
MBD	Model Bidding Document
MCP	Market Clearing Price
MOP	Ministry of Power
MPDCL	Meghalaya Power Distribution Corporation Limited
MPP	Merchant Power Plant
MPPGCL	Madhya Pradesh Power Generating Company Limited
MPPMCL	MP Power Management Company Limited
MSEDCL	Maharashtra State Electricity Distribution Co. Ltd.
MU	Million Units
MVA	Mega Volt Ampere
MW	Mega Watts
MWh	Mega Watt Hour
NCAS	Network Control Ancillary Services
NCTP	National Capital Thermal Power Plant
NEEPCO	North Eastern Electric Power Corporation Limited
NER	North Eastern Region
NEW Grid	North-East-North East-West Grid
NHDC	National Hydro Development Corporation Limited
NHPC	NHPC Limited
NLC	NLC India Limited
NLDC	National Load Dispatch Centre
NR	Northern Region
NRSS	Northern Region Strengthening Scheme
NSGM	National Smart Grid Mission
NTPC	NTPC Limited
NTPL	NLC Tamil Nadu Power Limited

Abbreviation	Expanded Version
OA	Open Access
OAC	Open Access Consumer
OTP	Other than RTC and Peak period
OTPC	ONGC Tripura Power Company
PCKL	Power Company of Karnataka Limited
PFC	Power Finance Corporation
PGCIL/POWERGRID	Power Grid Corporation of India Limited
POSOCO	Power System Operation Corporation Limited
PPA	Power Purchase Agreement
PSPCL	Punjab State Power Corporation Limited
PX	Power Exchange
PXIL	Power Exchange India Limited
RE	Renewable Energy
REC	Renewable Energy Certificate
RES	Renewable Energy Sources
RFP	Request for Proposal
RFQ	Request for Qualification
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RGPS	Ratnagiri Gas Power Station
RLDC	Regional Load Despatch Centre
ROR	Run of River
RPC	Regional Power Committee
RPO	Renewable Purchase Obligation
RRAS	Reserves Regulation Ancillary Services
RTC	Round The Clock
RTM	Real Time Market
RUVNL	Rajasthan Urja Vikas Nigam Limited
S1	Southern Region 1
S2	Southern Region 2
S3	Southern Region 3
SAARC	South Asian Association for Regional Cooperation
SBD	Standard Bidding Document
SEB	State Electricity Board
SHAKTI	Scheme for Harnessing and Allocating Koyala (Coal) Transparently in India
SJVNL	Satluj Jal Vidyut Nigam Limited

Abbreviation	Expanded Version
SRAS	System Restart Ancillary Services
SR Grid	Southern Region Grid
St	Stage
STPP	Super Thermal Power Plant
STPS	Super Thermal Power Station
TAM	Term Ahead Market
TANGEDCO	Tamil Nadu Generation and Distribution Corporation
THDC	Tehri Hydro Development Corporation Limited
TNEB	Tamil Nadu Electricity Board
TPP	Thermal Power Plant
TPS	Thermal Power Station
TSSPDCL	Telangana Southern Power Distribution Company Limited
TSPCC	Telangana State Power Coordination Committee
UDAY	Ujwal DISCOM Assurance Yojana
UMPP	Ultra Mega Power Projects
UPPCL	Uttar Pradesh Power Corporation Limited
UPCL	Uttarakhand Power Corporation Limited
VAE	Virtual Ancillary Entity
W1	Western Region 1
W2	Western Region 2
WBSEDCL	West Bengal State Electricity Distribution Company Ltd
WR	Western Region
WRSS	Western Region Strengthening Scheme

Executive Summary

The 'Report on Short-term Power Market in India: 2021-22' provides a snapshot of the developments in the power sector, with focus on short-term power transactions through different mechanisms by various market participants. The report broadly comprises of five sections, viz., overview of the power sector, trends in short-term power market in India, cross border trade of electricity, tariff of long-term sources of power, and transactions of renewable energy certificates.

The chapter on Overview of power sector discusses the year-wise trend in electricity generation, transmission and distribution, including revenue gap of state electricity distribution companies (DISCOMs)/SEBs, and the measures/reforms undertaken by the Government of India in the recent years. The salient features of the power sector, as discussed in the report, are as under:

1. Thermal energy (mainly from Coal) is an important source of electricity generation in India, contributing about 59.1% of the total installed generation capacity in 2021-22, followed by Renewable Energy Source (RES) (27.5%), Hydro (11.7%), and Nuclear (1.7%).

2. The Compound Annual Growth Rate (CAGR) of total installed generation capacity was 7.9% during the period from 2008-09 to 2021-22. The CAGR in RES was 17.7%, whereas it was 6.1% in all other sources during the period.

3. During the period from 2008-09 to 2021-22, the share of State sector in the total installed generation capacity declined from 54% to 26% and share of central sector declined from 31% to 25%, while the share of private sector increased from 15% to 49%. However, the public sector (centre and state combined) continues to be the largest owner, holding 51% share in 2021-22.

4. Gross electricity generation in India increased from 747.07 BU in 2008-09 to 1491.85 BU in 2021-22 and it increased at a CAGR of 5.5%.

5. The CAGR in gross electricity generation from 2008-09 to 2021-22 was relatively low (5.5%) when compared with the annual installed electricity generation capacity (7.9%).

6. Increase in the installed capacity resulted in decrease in the demand shortage (both energy and peak shortage). The energy shortage decreased from 11.1% in 2008-09 to about 0.4% in 2021-22, whereas peak deficit decreased from 11.9% to 1.2%.

7. During 2008-09 to 2021-22, the bulk transmission grew at a CAGR of 5.8%, while the growth in the transmission capacity of substations was at the rate of 10.9%.

8. The annual transmission charges increased at a CAGR of 16.91% during period from 2011-12 to 2021-22.

9. The total electricity consumption increased from 611.29 BU in 2008-09 to 1227.00 BU in 2020-21 (estimated) registering an CAGR of 6.0%. During the period, per-capita consumption of electricity also increased from 734 kWh to 1161 kWh at a CAGR of 3.9%.

10. All India average cost of supply and average revenue (without subsidy) of state power utilities increased from ₹3.40/kWh and ₹2.63/kwh, respectively, in 2008-09 to ₹6.19/kWh and ₹4.71/kWh, respectively, in 2020-21. During the latest 5 years, the revenue as percentage of cost was varying between 76% and 81%, indicating that the weighted average tariff for all categories of consumers was about 20% lower than the weighted average cost of supply.

'Short-term transactions of electricity' refers to contracts of less than one-year period for electricity transacted under bilateral transactions through Inter-State Trading Licensees (only inter-State part) and directly by the Distribution Licensees (also referred as Distribution Companies or DISCOMs), Power Exchanges {Indian Energy Exchange Ltd. (IEX) and Power Exchange India Ltd. (PXIL)}, and Deviation Settlement Mechanism (DSM). The analysis of short-term power market includes: (i) yearly/monthly/daily trends in short-term transactions of electricity; (ii) time of the day variation in volume and price of electricity transacted through traders and power exchanges; (iii) trading margin charged by trading licensees for bilateral transactions (iv) analysis of open access consumers on power exchanges; (v) major sellers and buyers of electricity in the short term market; (vi) effect of congestion on volume of electricity transacted through power exchanges; and (vii) ancillary services operations. Salient features of the short-term power market during 2021-22 are as under:

1. Of the total electricity procured in India in 2021-22, the short-term power market comprised about 12.5%. The balance 87.5% of generation was procured mainly by distribution companies through long-term contracts and short-term intra-State transactions.

2. During 2009-10 to 2021-22, the volume of short-term transactions of electricity increased at a higher rate (CAGR of 9.1%) when compared with the gross electricity generation (CAGR of 6.9%).

3. In terms of volume, the size of the short-term market in India increased from 146.01 BU in 2020-21 to 186.75 BU in the year 2021-22, registering annual growth of about 28%.

4. Excluding DSM and direct bilateral sale between the DISCOMs, the volume of electricity transacted was 140.92 BU in 2021-22. This was about 33% higher than in 2020-21. In monetary terms, the size of this segment of the short-term market was ₹62,286 crore in the year 2021-22[1], which was about 89% more than in the year 2020-21. The increase in size of the market was mainly due to significantly increased volumes transacted through power exchanges and traders.

5. The volume of electricity transacted through power exchanges increased at a CAGR of 31.9%, and the volume of electricity transacted through traders increased at CAGR of 4.6% during 2008-09 to 2021-22.

6. The volume of DSM transactions increased by 10% in 2021-22 over the year 2020-21. The share of DSM as a percentage of total volume of short-term transactions of electricity continued a downward trend in past years and it declined from 39.2% in 2009-10 to 13.5% in 2021-22.

[1]*excluding banking transactions*

7. In terms of volume, the direct bilateral transactions between DISCOMs witnessed an increase of about 22% in 2021-22 as compared to 2020-21. The share of direct bilateral transactions between DISCOMs as a percentage of total short term transaction volume increased from 9.4% in 2009-10 to 11.0% in 2021-22.

8. The weighted average price of electricity transacted through power exchanges was ₹4.69/kWh and through trading licensees it was ₹3.72/kWh in 2021-22. The corresponding values for the year 2020-21 were ₹2.98/kWh and ₹3.47/kWh, respectively. One new market segment was introduced on the power exchanges i.e. Green Day Ahead Market (October 2021 onwards) during 2021-22. The weighted average prices of electricity transacted through Day Ahead Market, Green Day Ahead Market, Real Time Market, Term Ahead Market and Green Term Ahead Market sub-segment of the power exchanges in 2021-22 were ₹4.78/kWh, ₹4.83/kWh, ₹4.54/kWh and ₹4.41/kWh and ₹4.63/kWh respectively.

9. The average price of DSM increased from December 2018 onwards as the DSM price vector was linked to daily average Area Clearing Price of power exchanges through CERC Deviation Settlement Mechanism and Related Matters (Fourth Amendment) Regulations, issued in November 2018. These regulations came into force with effect from 1st January 2019. The price of DSM increased from ₹2.82/kWh in 2020-21 to ₹3.75/kWh in 2021-22.

10. During 2021-22, 93% of the volume of electricity transacted through traders was at a price less than ₹5/kWh and 99% of the volume was transacted through traders at less than ₹10/kWh.

11. In Day Ahead Market, during 2021-22, 91% of the volume of electricity was transacted at a price less than ₹10/kWh, while about 70% of the volume was transacted at a price less than ₹5/kWh at IEX. In case of PXIL, 99.7% of the volume of electricity was transacted at a price less than ₹10/kWh and 89% of the volume was transacted at less than ₹5/kWh.

12. In Real Time Market (RTM), during 2021-22, 93% of the volume of electricity was transacted at a price less than ₹10/kWh while about 78% of the volume was transacted at a price less than ₹5/kWh at IEX. There was no trade in RTM on PXIL.

13. In Green Day Ahead market, during 2021-22 (started October 2021 onwards), about 96% of the volume of electricity was transacted at a price less than ₹ 10/kWh, while about 76% of the volume was transacted at a price less than ₹ 5/kWh, at IEX. There was no trade in G-DAM segment on PXIL.

14. During 2021-22, of the total electricity bought under bilateral transactions from traders, 89% was on round the clock (RTC) basis, followed by 10% in periods other than RTC and peak (OTP) and 1% was during peak hours. The per unit price of electricity procured during Peak period was high (₹ 4.70/kWh) when compared with the price during RTC (₹3.64/kWh) and OTP (₹3.97/kWh).

15. It is observed from the block-wise and region-wise prices of electricity transacted through power exchanges in 2021-22, that the price of electricity in Southern Region was marginally higher than the price in other regions during peak period only in RTM.

16. During 2008-09 to 2021-22, number of traders who were undertaking trading increased from 15 to 29. The Herfindahl-Hirschman Index (HHI), based on volume of electricity transacted in short-term through traders, increased from 0.1630 in 2008-09 to 0.2431 in 2021-22. The concentration of market power, in terms of volume of electricity transacted through traders/trading licensees, was moderate in 2021-22. The competition among the traders resulted in an increase in volume and decrease in prices in the short-term bilateral market.

17. The weighted average trading margin charged by the trading licensees in 2021-22 was ₹0.035/kWh, which is in line with the CERC Trading License Regulations, 2020.

18. In both the power exchanges, Open Access industrial consumers bought 9.74 BU of electricity, which formed 11% of the total day ahead, green day ahead and real time market volume transacted in the power exchanges during 2021-22.

19. The weighted average price of electricity bought by open access consumers at IEX was ₹3.20/kWh, which was lower as compared to the weighted average price of the total electricity transacted through IEX (₹4.73/kWh), i.e., through day ahead, green day ahead & real time market. However, the weighted average price of electricity bought by Open Access Consumer (₹4.99/kWh), was higher compared to weighted average price of the total electricity transacted though PXIL (₹3.68/kWh) in 2021-22.

20. The year witnessed very few constraints on the volume of electricity transacted through power exchanges, mainly due to transmission congestion. During 2021-22, the actual transacted volume was about 0.09% less than the unconstrained volume. Due to few instances of congestion and the splitting of market, the congestion amount collected during the year was ₹23.35 crore.

21. The energy scheduled under Regulation UP of RRAS increased from 2212.28 MU in 2016-17 to 2778.22 MU in 2021-22. The energy scheduled under Regulation DOWN of RRAS increased from 286.00 MU in 2016-17 to 5353.44 MU in 2021-22.

Salient features of the cross border trade of electricity, tariff of long-term sources of power, and renewable energy certificates transacted through power exchanges are as under:

1. India has been importing electricity from Bhutan and exporting electricity to Bangladesh, Nepal, and Myanmar. India is a net exporter of electricity from 2016-17 onwards.

2. During 2021-22, the trading session of RECs remained suspended till October 2021 and resumed from November 2021. During the period from November 2021 to March 2022, the number of Solar RECs transacted on Power exchanges was 13.63 lakh and the weighted average market clearing price of these RECs was ₹2195/MWh. During the same period, the number of Non-solar RECs transacted on power exchanges was 70.98 lakh and the weighted average market clearing price of these RECs was ₹1000/MWh.

***

Chapter-I

Overview of Power Sector

The Indian power sector is one of the most diversified in the world. The growing energy needs of the economy are being catered to by continual addition in generation capacity of various sources. The entire electricity supply chain has undergone a phase of transformation in the process of advancing reforms in the sector. This chapter provides an overview of the developments made in the electricity supply chain over the years, and the new policy initiatives being undertaken to address some of the key challenges faced by the sector.

1. Generation

The sources of electricity generation in India can be broadly classified into conventional and non-conventional. The conventional sources of power generation are thermal (coal, lignite, natural gas, and oil), hydro and nuclear power, whereas non-conventional sources of power generation (renewable energy sources), include wind, solar, agricultural and domestic waste, etc. Table-1 and Figure-1 show the installed electricity generation capacity in India by different sources.

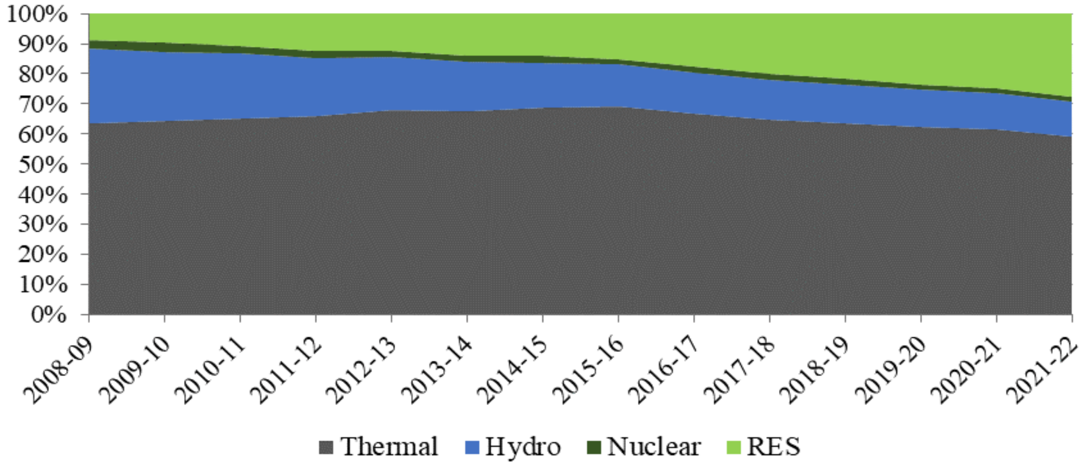
Table-1: Installed Electricity Generation Capacity in India (GW), 2008-09 to 2021-22

Year	Thermal	Hydro	Nuclear	RES	Total
2008-09	93.73	36.88	4.12	13.24	147.97
2009-10	102.45	36.86	4.56	15.52	159.40
2010-11	112.82	37.57	4.78	18.45	173.63
2011-12	131.60	38.99	4.78	24.50	199.88
2012-13	151.53	39.49	4.78	27.54	223.34
2013-14	168.26	40.53	4.78	34.99	248.55
2014-15	188.90	41.27	5.78	38.96	274.90
2015-16	210.68	42.78	5.78	45.92	305.16
2016-17	218.33	44.48	6.78	57.24	326.83
2017-18	222.91	45.29	6.78	69.02	344.00
2018-19	226.28	45.40	6.78	77.64	356.10
2019-20	230.81	45.70	6.78	86.76	370.05
2020-21	234.73	46.21	6.78	94.43	382.15
2021-22*	236.11	46.72	6.78	109.89	399.50

Source: CEA, Growth of Electricity Sector in India, various issues

* *Provisional*

Figure-1: Installed Electricity Generation Capacity in India (%), 2008-09 to 2021-22



As may be observed in Figure-1, thermal continues to be the major source of electricity generation in India, contributing 59.1% of the total capacity of generation in 2021-22, followed by Renewable Energy Source (RES) (27.5%), Hydro (11.7%) and Nuclear (1.7%). However, the share of thermal based generation capacity in the total installed capacity has been declining gradually from 2015-16 onwards, i.e., from 69.0% in 2015-16 to 59.1% in 2021-22. During the period from 2008-09 to 2021-22, the share of hydro based generation capacity decreased from 24.9% to 11.7%, whereas renewables-based generation capacity witnessed an increase from 8.9% to 27.5%. The CAGR of total installed electricity generation capacity during the period was about 7.9% during the period as compared to 17.7% in RES and 6.1% in all other sources.

The Electricity Act of 2003 liberalised the process of electricity generation by shifting towards a license-free regime. This has resulted in increased competition in the generation segment and the share of private players witnessed a significant increase in the total electricity generation.

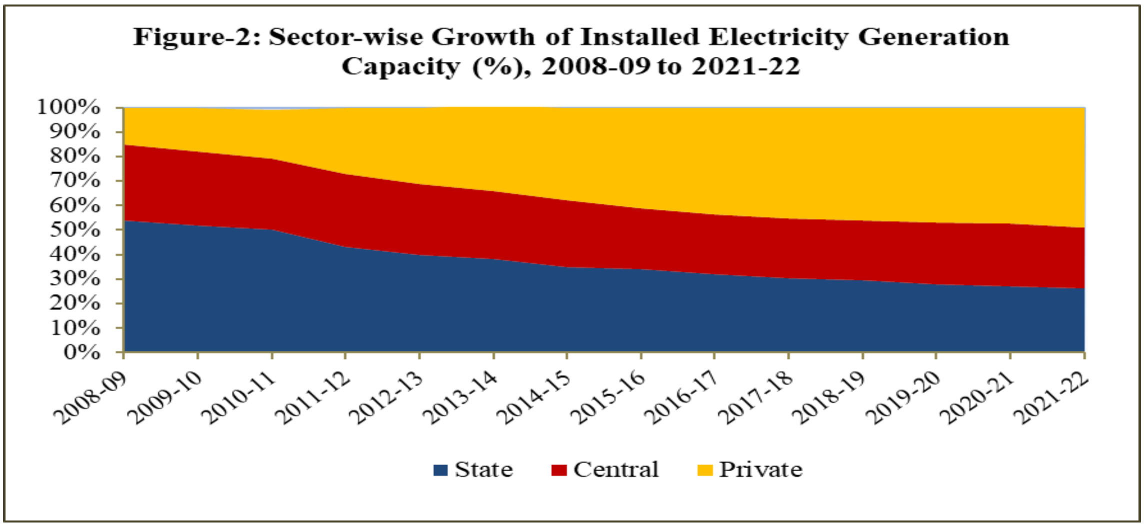
The players in the electricity generation segment can be divided into three types based on ownership and operations. These are: (i) Central public sector undertakings; (ii) State public sector undertakings/State Electricity Boards; and (iii) Private sector enterprises.

Sector-wise growth of installed generation capacity is shown in Table-2 and Figure-2. It can be observed from the table that the CAGR of total installed generation capacity was about 7.9% during the period from 2008-09 to 2021-22. During the period, the share of state sector in the total installed generation capacity has declined from 54% to 26% and the share of central sector has declined from 31% to 25%, whereas the share of private sector has increased significantly, i.e., from 15% to 49%. However, the public sector, including state and central continues to be the majority owner, holding 51% share in total installed generation capacity.

Table-2: Sector-wise Growth of Installed Electricity Generation Capacity, 2008-09 to 2021-22

Year	Installed Generation Capacity (GW)			
	State	Central	Private	Total
2008-09	79.31	45.78	22.88	147.97
2009-10	82.91	47.48	29.01	159.40
2010-11	87.42	50.76	35.45	173.63
2011-12	85.92	59.68	54.28	199.88
2012-13	89.13	65.36	68.86	223.34
2013-14	92.27	68.13	84.87	245.26
2014-15	95.08	72.52	104.12	271.72
2015-16	101.79	76.30	124.00	302.09
2016-17	103.97	80.26	142.62	326.85
2017-18	103.97	84.52	155.51	344.00
2018-19	105.08	86.60	164.43	356.10
2019-20	103.53	93.48	173.04	370.05
2020-21	103.87	97.51	180.77	382.15
2021-22*	104.85	99.00	195.64	399.50

* *Provisional*
Source: CEA, Growth of Electricity Sector in India, various issues



Source-wise gross electricity generation in India is shown in Table-3 and Figure-3. As may be observed from the table, gross electricity generation in India has increased from 747.07 BU in 2008-09 to 1491.85 BU in 2021-22, at a CAGR of about 5.5%. The growth in gross electricity generation was low when compared with the growth in annual installed electricity generation capacity (7.9%). This may be primarily due to increase in capacity from RES with low utilization factor.

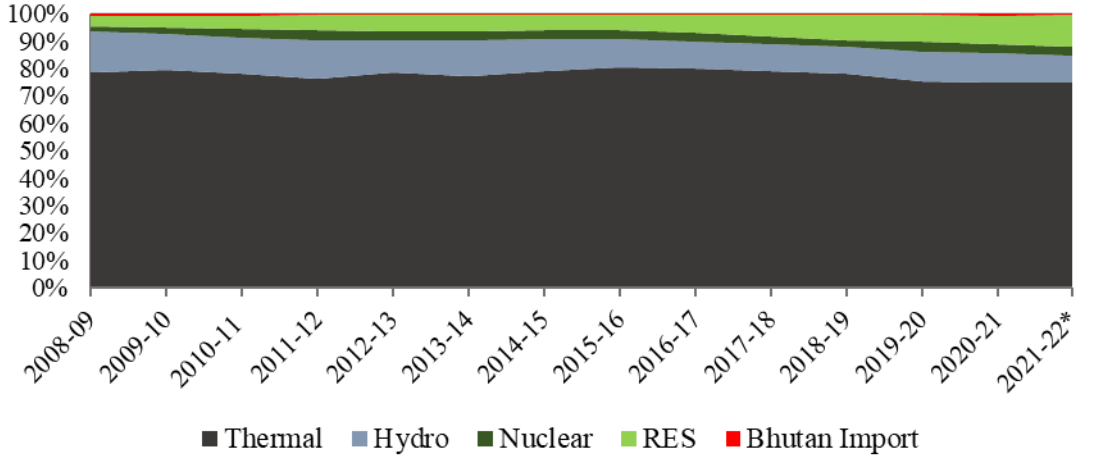
Table-3: Gross Electricity Generation in India (BU), 2008-09 to 2021-22

Year	Thermal	Hydro	Nuclear	RES	Bhutan Import	Total
2008-09	588.28	110.10	14.93	27.86	5.90	747.07
2009-10	640.21	104.06	18.64	36.95	5.40	805.26
2010-11	665.00	114.30	26.30	41.15	5.60	852.35
2011-12	708.43	130.51	32.29	51.23	5.30	927.76
2012-13	760.45	113.72	32.87	57.45	4.80	969.29
2013-14	792.05	134.85	34.23	59.62	5.60	1026.35
2014-15	877.94	129.24	36.10	61.79	5.00	1110.07
2015-16	943.01	121.38	37.41	65.78	5.20	1172.78
2016-17	994.22	122.31	37.66	81.87	5.64	1241.70
2017-18	1037.06	126.12	38.35	101.84	4.78	1308.15
2018-19	1072.00	135.00	37.70	126.76	4.40	1375.86
2019-20	1044.45	155.67	46.38	138.32	5.81	1390.63
2020-21	1032.51	150.30	43.03	147.25	8.77	1381.86
2021-22*	1114.71	151.63	47.11	170.90	7.49	1491.85

**Provisional*

Source: CEA, Growth of Electricity Sector in India, various issues.

Figure-3: Gross Electricity Generation in India(%), 2008-09 to 2021-22



*Provisional

Of all the sources, electricity generation from thermal source (mainly coal) plays a dominant role in the energy-mix, with a share of about 75% in 2021-22. Though its relative share continues to be the highest, it has shown a declining trend over the last few years mainly because of increasing emphasis on renewable energy sources. The amount of electricity generated from RES increased from 3.7% in 2008-09 to 11.5% in 2021-22.

The increase in installed electricity generation capacity as shown in Table-1, had a positive impact on the power supply position. Both energy requirement and peak demand increased from 777.04 BU and 109.81 GW respectively in 2008-09 to 1379.81 BU and 203.01 GW, respectively in 2021-22 (Table-4). Increase in the installed capacity resulted in decrease in the energy and peak deficit from 11.1% and 11.9% respectively in 2008-09 to about 0.4% and 1.2%, respectively in 2021-22 (Figure-4).

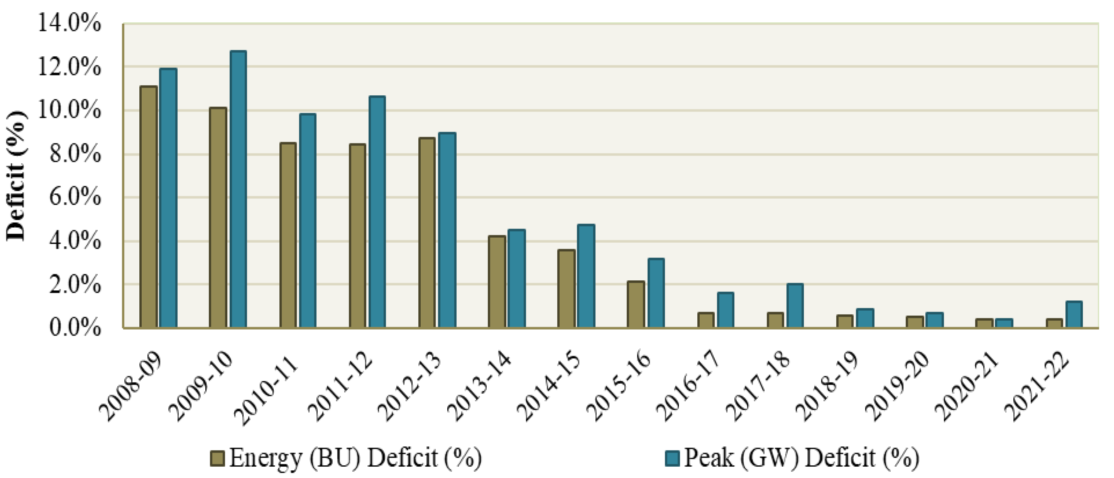
As per the announcement made by the Hon'ble Prime Minister in COP26 Summit at Glasgow in November 2021, Government of India has set an ambitious target for enhancement of non-fossil fuel energy capacity to 500 GW by 2030. The commitment regarding non-fossil fuel energy capacity is proposed to be met mainly from the installation of solar and wind power capacities. This will further enable diversification of India's energy mix with increasing share of renewable resources.

Table-4: Power Supply Position in India, 2008-09 to 2021-22

Year	Energy (BU)			Peak (GW)		
	Require-ment	Availability	Deficit (%)	Peak Demand	Peak Met	Deficit (%)
2008-09	777.04	691.04	11.1%	109.81	96.79	11.9%
2009-10	830.59	746.64	10.1%	119.17	104.01	12.7%
2010-11	861.59	788.36	8.5%	122.29	110.26	9.8%
2011-12	937.20	857.89	8.5%	130.01	116.19	10.6%
2012-13	995.56	908.65	8.7%	135.45	123.29	9.0%
2013-14	1002.26	959.83	4.2%	135.92	129.82	4.5%
2014-15	1068.92	1030.79	3.6%	148.17	141.16	4.7%
2015-16	1114.41	1090.85	2.1%	153.37	148.46	3.2%
2016-17	1142.93	1135.33	0.7%	159.54	156.93	1.6%
2017-18	1213.33	1204.70	0.7%	164.07	160.75	2.0%
2018-19	1274.60	1267.53	0.6%	177.02	175.53	0.8%
2019-20	1291.01	1284.44	0.5%	183.80	182.53	0.7%
2020-21	1275.53	1270.66	0.4%	190.20	189.40	0.4%
2021-22	1379.81	1374.02	0.4%	203.01	200.54	1.2%

Source: Ministry of Power

Figure-4: Energy Deficit and Peak Deficit in India, 2008-09 to 2021-22



2. Transmission

The transmission sector was opened for private investments in 1998. The Central Transmission Utility (CTU) is the nodal agency for providing medium-term (3 months to 5 years) and long-term (exceeding 7 years) access (the right to use the inter-state transmission system) typically required by a generating station or a trader acting on the station's behalf. The PGCIL has been responsible for inter-state transmission and development of the national grid, and acts as the CTU. The RLDCs are the nodal agencies for grant of short-term open access (upto 3 months). The nodal agency providing transmission access to the power exchanges is the NLDC.

Open Access refers to the right to generators of electricity [Captive Power Plants[2] (CPP)/Independent Power Producers (IPP)] and bulk consumers[3] to sell the generated electricity at a certain transmission surcharge and to access the transmission and distribution networks of any generator without any discrimination by the distribution/transmission line owners. The principle of open access is based on the premise that while it is uneconomical to lay down multiple transmission lines in the same region because of the large sunk costs involved, it is still best to give consumers a choice to decide which firm's electricity they want to consume.

The growth of transmission system (transmission lines and transformation capacity) in India during 2008-09 to 2021-22 is shown in Table-5 and Figure-5.

Table-5: Growth of Transmission System in India, 2008-09 to 2021-22

Year	Transmission Lines (AC+HVDC) (ckm)	Transformation Capacity of Substations (220KV and above) (MVA)
2008-09	220794	288615
2009-10	236467	310052
2010-11	254536	345513
2011-12	257481	409551
2012-13	274588	473216
2013-14	291336	530546

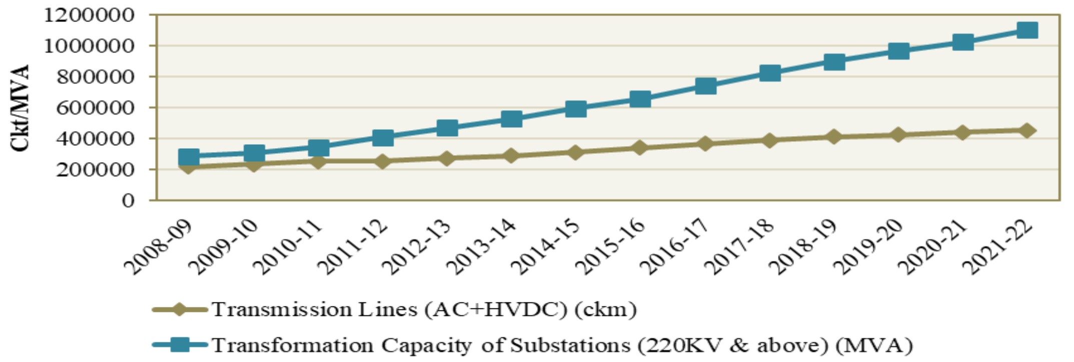
[2] *Captive Power refers to generation from a unit set up by industry for its own consumption*

[3] *Bulk consumers are consumers with power requirement of 1MW or above*

2014-15	313437	596100
2015-16	341551	658949
2016-17	367851	740765
2017-18	390970	826958
2018-19	413407	899663
2019-20	425071	967893
2020-21	441821	1025468
2021-22	456716	1104450

Source: CEA, Monthly Reports

Figure-5: Growth of Transmission System in India, 2008-09 to 2021-22



It can be observed from Table-5 that bulk transmission (transmission lines 220 kV & above) has increased from 2.21 lakh ckm in 2008-09 to 4.57 lakh ckm in 2021-22. During the period, the transformation capacity of sub-stations has also increased from 2.89 lakh MVA to 11.04 lakh MVA. The CAGR during the period in the transmission lines and transformation capacity of sub-stations was 5.8% and 10.9% respectively. Table-6 provides the data on annual transmission charges (transmission charges applicable for transmission lines owned by PGCIL and other ISTS licensees) for the period from 2011-12 to 2021-22. The annual transmission charges increased at a CAGR of 16.91% during the period. There are various reasons for increase in annual transmission charges, like the growth of transmission lines (especially at higher voltage levels), waiver of transmission charges for inter-state renewable energy generators, and relinquishment of long-term access (LTA).

Table-6: Annual Transmission Charges, 2011-12 to 2021-22

Year	Transmission Charges as on 31st March (₹ Crore)
2011-12	8743
2012-13	12797
2013-14	15118

2014-15	17680
2015-16	22476
2016-17	27383
2017-18	31405
2018-19	35599
2019-20	39285
2020-21	41051
2021-22	41696

Source: POSOCO

Notes: (i) New Sharing of ISTS Charges & Losses Regulations have been notified by CERC, w.e.f 01.11.2020. Thereafter NLDC, instead of CERC, notifies the Transmission pricing every month. The Notification for billing month May 2022 has been used for obtaining the approved Yearly Transmission Charges for March 2022, (ii) The above transmission charges are the same as used for computation of POC Charges.

Transmission sector is having a natural monopoly, as is involves high sunk costs in investing in the infrastructure needed to transmit electricity, such as transmission lines. Because of these characteristics, non-public entities face entry barriers, and private investments are allowed in transmission projects only after the approval from CERC. Although the transmission market is largely dominated by the public sector, there are many lines including High-Voltage Direct Current (HVDC) lines owned by private players. As on 31.3.2022, about 69 Inter-state transmission licensees have been granted approval by CERC (Annexure-I).

During the year 2021-22, a number of policy measures and initiatives were introduced in the transmission sector, including separation of CTU functions from PGCIL to bring in more transparency in transmission planning and foster investment, notification of Revised Guidelines and Standard Bidding Documents for procurement of Inter-State Transmission Services (ISTS) through Tariff based Competitive Bidding (TBCB) process, dated 06.08.2021. In addition, Electricity (Transmission System Planning, Development and Recovery of Inter-State Transmission Charges) Rules 2021 were promulgated by MoP for complete overhauling of transmission system planning to give power sector utilities easier access to electricity transmission network across the country.

3. Distribution

Distribution is the last leg in the electricity supply chain and assumes significant importance in the overall performance of the sector. State Electricity Distribution Companies (DISCOMs)/State Electricity Boards (SEBs) own the majority of the distribution segment in the electricity supply chain. In order to boost competition and make the sector more efficient, the Government is emphasizing the importance of a well-performing distribution sector and has been focusing on the improvement of the financial health of utilities. This is necessary to meet the goal of providing people a reliable and good-quality power and universal access to electricity. To meet this goal, it is required to increase rural electrification, reduce aggregate technical and commercial (AT&C) losses incurred while distributing electricity, ensuring financial viability of DISCOMs, and encourage private sector participation.

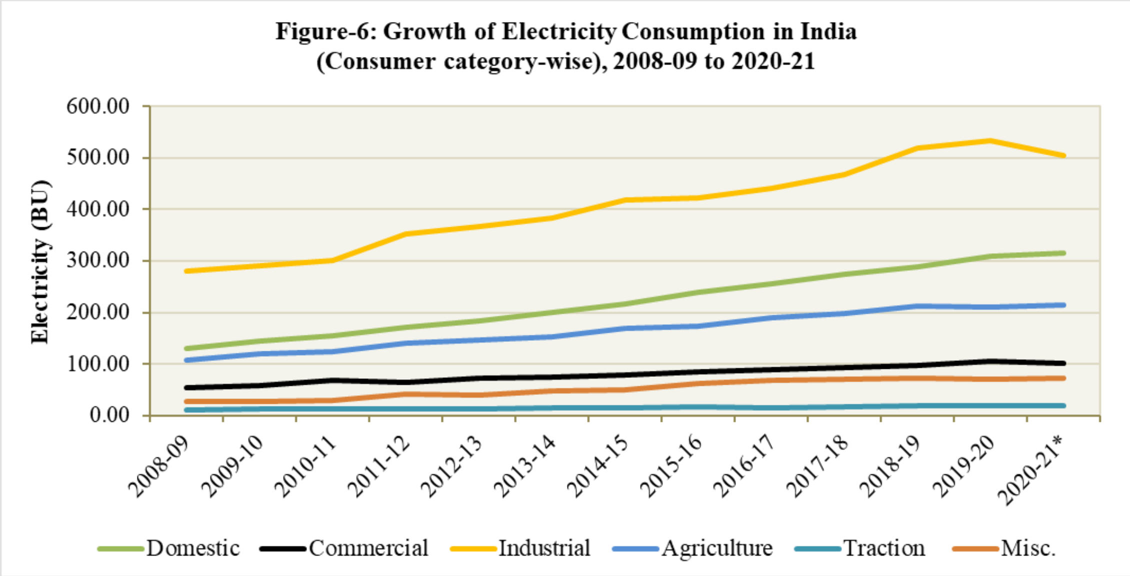
The growth in electricity consumption (consumer category-wise) is provided in Table-7 & Figure-6. The total electricity consumption increased from 611.29 BU in 2008-09 to 1227.00 BU in 2020-21 (estimated) at a CAGR of 6.0%. During the period, per capita consumption of electricity in India has increased from 734 kWh to 1161 kWh (provisional), registering a CAGR of 3.9%. Despite this considerable growth, the level of per capita energy consumption in India is low as compared to the international average of around 3260 kWh for 2018 (latest available year).

Table-7: Growth of Electricity Consumption in India (Consumer category-wise) (BU), 2008-09 to 2020-21

Year	Domestic	Commer-cial	Indus-trial	Agri-culture	Traction	Misc.	Total
2008-09	130.06	53.54	279.66	107.78	11.81	28.45	611.29
2009-10	144.25	59.30	290.26	119.32	12.41	27.71	653.24
2010-11	156.02	68.72	301.26	123.39	13.09	29.93	692.40
2011-12	171.10	65.38	352.29	140.96	14.21	41.25	785.19
2012-13	183.70	72.79	365.99	147.46	14.10	40.26	824.30
2013-14	199.84	74.25	384.42	152.74	15.54	47.42	874.21
2014-15	217.41	78.39	418.35	168.91	16.18	49.29	948.52
2015-16	238.88	86.04	423.52	173.19	16.59	62.98	1001.19
2016-17	255.83	89.83	440.21	191.15	15.68	68.49	1061.18
2017-18	273.55	93.76	468.61	199.25	17.43	70.83	1123.43
2018-19	288.24	98.23	519.20	213.41	18.84	72.06	1209.97
2019-20	308.75	106.05	532.82	211.30	19.15	70.03	1248.09
2020-21*	315.00	102.00	504.20	215.00	18.50	72.30	1227.00

** Estimated*

Source: CEA, Growth of Electricity Sector in India, various issues.



** Estimated*

As per the latest available 'Report on Performance of State Power Utilities-2020-21' published by Power Finance Corporation Ltd (PFC), the average all-India AT&C losses were about 22.32% in 2020-21[4]. More than 90% of these losses can be attributed to Transmission and Distribution Losses, which correspond to electricity produced but not paid for.

The electricity tariffs charged by the DISCOMs are not cost reflective for various reasons. The DISCOMs sell electricity below cost or provide electricity at free/subsidized rates for agriculture and domestic consumers. The tariffs for residential and agricultural consumers are subsidized by overcharging industrial and commercial users. Average cost of supply and average revenue of all state power utilities has been provided for the period from 2008-09 to 2020-21 in Table-8 and Figure-7.

The all-India average cost of supply and average revenue (without subsidy) increased from ₹3.40/kWh and ₹2.63/kWh respectively in 2008-09 to ₹6.19/kWh and ₹ 4.71/kWh, respectively, in 2020-21. Here the average revenue includes revenue from operations, regulatory income, revenue grants under UDAY and other income. The gap between the cost of supply and revenue has increased from ₹0.77/kWh to ₹1.48/kWh during the period. The revenue as percentage of cost of supply varied between 76% to

[4] As per the revised methodology for calculation of AT&C losses notified by CEA.

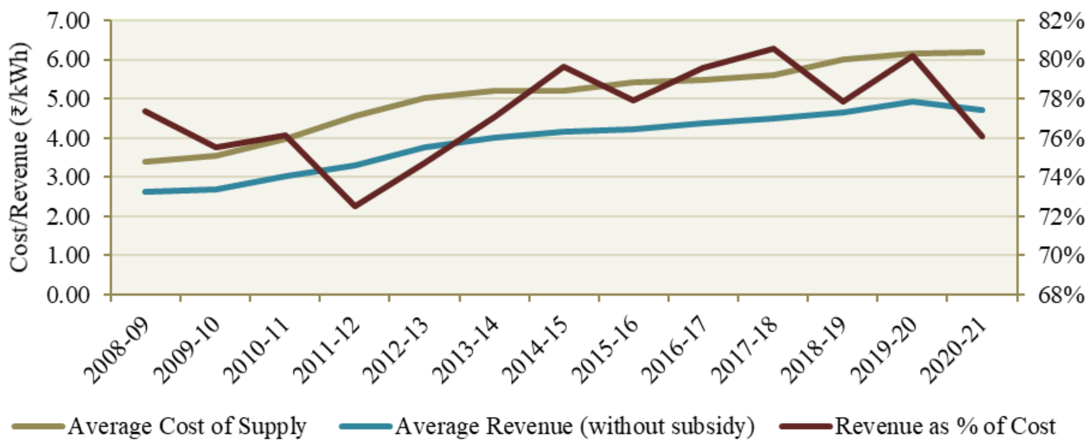
81% during the recent five years, which indicates that the average revenue was about 21% lower than the average cost of supply and this gap is financed through budgetary support as subsidy by the Government.

Table-8: Average Cost of Supply and Average Revenue of State Power Utilities, 2008-09 to 2020-21

Year	Average Cost of Supply (₹/kWh)	Average Revenue (without subsidy) (₹/kWh)	Revenue Gap (₹/kWh)	Revenue as % of Cost
2008-09	3.40	2.63	0.77	77%
2009-10	3.55	2.68	0.87	75%
2010-11	3.98	3.03	0.95	76%
2011-12	4.55	3.30	1.25	73%
2012-13	5.03	3.76	1.27	75%
2013-14	5.19	4.00	1.19	77%
2014-15	5.21	4.15	1.06	80%
2015-16	5.43	4.23	1.20	78%
2016-17	5.48	4.36	1.12	80%
2017-18	5.60	4.51	1.09	81%
2018-19	6.00	4.65	1.35	78%
2019-20	6.15	4.93	1.22	80%
2020-21	6.19	4.71	1.48	76%

Source: PFC, Report on The Performance of State Power Utilities, various issues

Figure-7: Average Cost of Supply and Average Revenue of State Power Utilities, 2008-09 to 2020-21



Due to some of the legacy issues, the DISCOMs are financially stressed with huge operational losses and outstanding debt. Due to which, DISCOMs find it difficult to supply adequate power at affordable rates. To improve their financial health, several policy initiatives have been taken by the Union Government during the last few years, which include implementation of Ujwal DISCOM Assurance Yojana (UDAY, launched in 2015), Integrated Power Development Scheme (IPDS, launched in 2014), National Smart Grid Mission (NSGM), etc. UDAY is being implemented in various States for the financial turnaround and revival of the DISCOMs through four initiatives (i) improving operational efficiencies of DISCOMs; (ii) reduction of cost of power purchase; (iii) reduction in interest cost of DISCOMs; and (iv) enforcing financial discipline on DISCOMs through alignment with State finances.

The IPDS works with the objectives of reducing AT&C losses, establishment of IT enabled energy accounting/auditing system, improvement in billed energy based on metered consumption and improvement in collection efficiency and the scheme is focused on urban areas. The Deen Dayal Upadhyaya Gram Jyoti Yojana (DDUGJY, launched in 2014) is centred on improving distribution and electrification in rural areas. The scheme includes the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) as a key component of the rural electrification initiative.

The Pradhan Mantri Sahaj Bijli Har Ghar Yojana (Saubhagya Scheme) was launched in September 2017, to provide free electricity connections to all households, for above poverty line (APL) & poor families in rural areas and poor families in urban areas. All DISCOMs, including Private Sector DISCOMs, State Power Departments and Renewable Energy Cooperative Societies shall be eligible for financial assistance under the scheme in line with DDUGJY.

These schemes have helped the DISCOMs in strengthening and augmenting of sub-transmission and distribution network, and also IT enablement. These schemes have supported in achieving the goal of providing universal electricity access to the households enabling significant improvement in availability of power supply in both rural and urban areas.

During the FY 2021-22, a number of new policy initiatives have been undertaken to tackle these financial and operational issues of DISCOMs, including their corporate governance & financial liquidity, steps towards technological advancement, etc. MoP has launched the Revamped Distribution Sector Scheme (RDSS) dated 20.07.2021, with the aim to provide reform-based result-linked financial assistance to DISCOMs to strengthen the supply infrastructure. Main objectives of the scheme include: (i) Reduction of AT&C losses to pan-India levels of 12-15% by FY 2024-25; (ii) Reduction of ACS-ARR gap to zero by FY 2024-25; (iii) improvement in the quality, reliability and affordability of power supply to consumers through a financially sustainable and operationally efficient distribution sector; and (iv) modernization of the DISCOMs through technology enhancement in the areas of asset management, customer experience and business operations. With a view to improve the operational and financial performance, and accountability of DISCOMs, the MoP has issued the 'Guidelines for Corporate Governance of State Power Distribution Utilities (DISCOMs)'.

***

Chapter-II

Short-term Power Market in India

1. Introduction

Prior to the Electricity Act 2003, the electricity industry recognized generation, transmission, and supply as three principal activities, and the legal provisions were also woven around these concepts. With the enactment of the Electricity Act 2003, the transactions involving purchase and sale of electricity has been recognized as a distinct licensed activity. Recognition of trading as a separate activity is in sync with the overall framework of encouraging competition in all segments of the electricity industry. The Electricity Act 2003, laid down provisions for promoting competition in the Indian power market. Introduction of non-discriminatory open access in electricity sector provided further impetus for enhancing competition in the market. The responsibility of developing the market in electricity has been vested with the Regulatory Commissions. The open access regulations, inter-state trading regulations, power market regulations, etc., of the Central Commission have facilitated power trading in an organized manner. In exercise of the powers conferred under section 178 of the Electricity Act, 2003, the Commission had notified the CERC (Procedure, Terms and Conditions for grant of trading licence and other related matters) Regulations, 2009 in February 2009 and the CERC (Fixation of Trading Margin) Regulations, 2010 in January 2010.

Over the past decade, the Indian power sector has undergone many developments like increased volume of electricity traded on power exchanges, introduction of new type of energy procurement & sale contracts, cross border trade of electricity, etc. Considering the developments, the Commission notified the CERC (Procedure, Terms and Conditions for grant of Trading Licence and other related matters) Regulations, 2020 in January 2020, repealing the earlier Regulations.

The Regulations specify the terms and conditions for grant of trading licence and other related matters including but not limited to capital adequacy and liquidity requirements, obligations of the trading licensees, requirements for submission of information, penalties for contravention and non-compliance by the trading licensees and the trading margin that shall be charged by the trading licensees for various types of contracts.

To serve the growing volumes of electricity trade and increasing penetration of renewable energy in the grid, the Commission has also introduced new market segments on the Power Exchanges, namely the Real Time Market (RTM) and the Green Term Ahead Market (GTAM), in the year 2020-21. RTM has commenced on the power exchanges from 1st June 2020, to enable better portfolio management by the utilities with efficient power procurement planning, scheduling, and imbalance handling. The market provides the buyers & sellers, an organized platform for trading electricity closer to real time.

Providing a new avenue for renewable energy generators to sell power and for obligated entities to fulfil their RPOs, the GTAM was introduced on the Power exchanges from 1st August 2020. It is a market-based mechanism wherein RE surplus and RE deficit States can trade RE power and balance their RPO targets. This would incentivize RE resource-rich States to develop RE capacity beyond their obligation and aid in the development of RE capacity in India. The contracts in GTAM are similar to contracts in TAM.

With a view to provide avenues to existing and prospective Renewable Energy generators for sale of RE through the Power Exchange and to provide more options to the Obligated Entities to fulfil their RPOs, the Commission granted approval for introduction of Green Day Ahead Contract (GDAC) in Day Ahead Market (DAM) on the power exchanges in 2021-22. In G-DAM, the contracts enable buyers & seller to trade RE power on day ahead basis. The sellers are provided option to transfer their uncleared bids to DAM with flexibility to specify different price for uncleared bids in G-DAM. These contracts have been introduced on IEX from 27th October 2021 and on PXIL from 20th December 2021.

The Commission also granted approval for introduction of hydropower contracts in Green Term Ahead Market on IEX on 24th February 2022. These contracts would provide an additional avenue for the existing and prospective hydropower generators to sell the power. The obligated entities would able to procure hydropower through these contracts and thus meet their HPO requirements. These hydro GTAM contracts have been approved on the similar lines of existing contracts under GTAM.

The Chapter, in the following sections, provides a brief analysis of short-term[5] transactions of electricity in India over the years. Here, “short-term transactions of electricity” refers to the contracts less than one year for the following trades:

(a) Electricity traded under bilateral transactions through Inter-State Trading Licensees (only inter-state trades)
(b) Electricity traded directly by the Distribution Licensees (also referred as Distribution Companies or DISCOMs)
(c) Electricity traded through Power Exchanges
(d) Electricity transacted through Deviation Settlement Mechanism (DSM)

The analysis includes:

(i) Yearly/monthly/daily trends in short-term transactions of electricity
(ii) Time of the day variation in volume and price of electricity transacted through traders and power exchanges
(iii) Trading margin charged by trading licensees for bilateral transactions
(iv) Analysis of open access consumers on power exchanges
(v) Major sellers and buyers of electricity in the short-term market
(vi) Effect of congestion on volume of electricity transacted through power exchanges
(vii) Ancillary services operations

[5] *Although Deviation Settlement Mechanism (DSM) is not a market mechanism, electricity transacted under DSM is often considered a part of short-term transaction. Also, electricity transacted bilaterally directly between the distribution companies (without involving trading licensees or power exchanges) is considered a part of short-term market. In the year 2021-22, the volume of DSM was about 25.27 BU and that between distribution companies was about 20.56 BU.*

2. Yearly Trends in Short-term Transactions of Electricity (2009-10 to 2021-22)

The analysis on yearly trends in short-term transactions includes the electricity transacted through the following segments:

- Trading licensees (inter-state part only) under bilateral transactions or "bilateral trader" segment;
- Power exchange segment with transactions in Day Ahead Market, Green Day Ahead Market, Term Ahead Market, Green Term Ahead Market and Real Time Market;
- DSM segment; and
- Direct transactions of electricity between DISCOMs.

Inter-state trading licensees (traders) have been undertaking trading in electricity since 2004 and the power exchanges started operating since 2008. As on 31st March 2022, there were total 43 inter-state trading licensees (refer Annexure-II) and two power exchanges operating in the country. The two power exchanges namely, Indian Energy Exchange (IEX) and Power Exchange India Ltd. (PXIL) have started their operations in June 2008 and October 2008 respectively.

2.1 Total Short-term Transactions of Electricity with respect to Total Electricity Generation

Total volume of short-term transactions of electricity increased from 65.90 BU in 2009-10 to its all-time high of 186.75 BU in 2021-22. During the period, the volume of short-term transactions of electricity increased at a higher rate (CAGR of 9.1%) as compared to the total electricity generation[6] (CAGR of 6.9%). The volume of short-term transactions of electricity as percentage of total electricity generation varied from 8.9% to 12.5% during the period (Table-9).

[6] *Total electricity generation is the gross electricity generation in India as defined by CEA.*

Table-9: Volume of Short-term Transactions of Electricity with respect to Total Electricity Generation, 2009-10 to 2021-22

Year	Volume of Short-term Transactions of Electricity (BU)	Total Electricity Generation (BU)	Volume of Short-term Transactions of Electricity as % of Total Electricity Generation
2009-10	65.90	768.43	9.6%
2010-11	81.56	852.35	9.6%
2011-12	94.51	927.75	10.2%
2012-13	98.94	969.29	10.2%
2013-14	104.64	1026.34	10.2%
2014-15	98.99	1110.07	8.9%
2015-16	115.23	1172.78	9.8%
2016-17	119.23	1241.70	9.6%
2017-18	127.62	1308.15	9.8%
2018-19	145.20	1375.86	10.6%
2019-20	137.16	1390.93	9.9%
2020-21	146.01	1380.06	10.6%
2021-22*	186.75	1491.85	12.5%

**Provisional*

Source: NLDC & CEA

The analysis of yearly trends of short-term transactions of electricity for various segments, i.e., electricity transacted through traders and power exchanges, DSM, and directly between DISCOMs is presented in the following sections.

2.1.1 Electricity Transacted through Traders and Power Exchanges

Table-10(a), Table 10(b), Table-11 and Figure-8 show details of volume of electricity transacted through traders under bilateral transactions and through power exchanges from 2008-09 to 2021-22. The volume of electricity transacted through traders increased from 21.92 BU in 2008-09 to 39.47 BU in 2021-22 (Table 10(a)) at a CAGR of 4.6%.

Table-10(a): Volume of Electricity Transacted through Traders (BU), 2008-09 to 2021-22

Year	Electricity Transacted through Traders (BU)
2008-09	21.92
2009-10	26.72
2010-11	27.70
2011-12	35.84
2012-13	36.12
2013-14	35.11
2014-15	34.56
2015-16	35.43
2016-17	33.51
2017-18	38.94
2018-19	47.32
2019-20	29.95
2020-21	26.67
2021-22	39.47

Note: The volume of electricity transacted through traders in 2008-09 (April to July 2008) includes cross border trading and intra-state trading volume.
Source: NLDC data

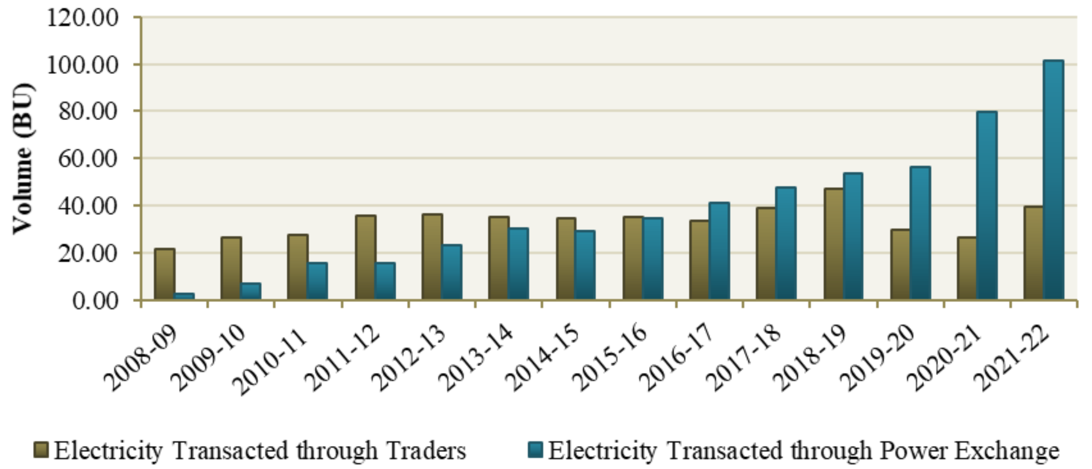
The volume of electricity transacted through power exchanges (IEX and PXIL) under different market segments increased from 2.77 BU in 2008-09 to 101.45 BU in 2021-22 (Table 10(a)). The CAGR in volume of this segment during 2008-09 to 2021-22 was 31.9%.

Table-10(b): Volume of Electricity Transacted through Power Exchanges (BU), 2008-09 to 2021-22

Year	Electricity Transacted through IEX					Electricity Transacted through PXIL					Total
	DAM	G-DAM	TAM	G-TAM	RTM	DAM	G-DAM	TAM	G-TAM	RTM	
2008-09	2.62	-	-	-	-	0.15	-	-	-	-	2.77
2009-10	6.17	-	0.10	-	-	0.92	-	0.003	-	-	7.19
2010-11	11.80	-	0.91	-	-	1.74	-	1.07	-	-	15.52
2011-12	13.79	-	0.62	-	-	1.03	-	0.11	-	-	15.54
2012-13	22.35	-	0.48	-	-	0.68	-	0.04	-	-	23.54
2013-14	28.92	-	0.34	-	-	1.11	-	0.30	-	-	30.67
2014-15	28.12	-	0.22	-	-	0.34	-	0.72	-	-	29.40
2015-16	33.96	-	0.33	-	-	0.14	-	0.58	-	-	35.01

2016-17	39.78	-	0.74	-	-	0.25	-	0.35	-	-	41.12
2017-18	44.84	-	1.37	-	-	0.73	-	0.75	-	-	47.70
2018-19	50.06	-	2.10	-	-	0.09	-	1.26	-	-	53.52
2019-20	49.11	-	4.77	-	-	0.05	-	2.52	-	-	56.45
2020-21	60.38	-	3.27	0.79	9.47	0.24	-	5.45	0.0004	0.002	79.59
2021-22	65.14	0.92	5.56	4.02	19.91	0.04	0.00	4.43	1.43	0.00	101.45

Figure-8: Volume of Electricity Transacted through Traders and Power Exchanges, 2008-09 to 2021-22



A comparison between the volume of electricity transacted through traders and power exchanges is shown in Figure-8. It can be observed that the volume of electricity transacted through traders was higher during 2008-09 to 2015-16, but from 2016-17 onwards the share of electricity transacted through power exchanges increased significantly. This indicates more demand for electricity is now being met through power exchanges than the bilateral transactions through traders.

The share of electricity transacted through traders and power exchanges as a percentage of total short-term transactions of electricity increased from about 51% in 2009-10 to 75% in 2021-22 (Table-11).

Table-11: Electricity Transacted through Traders and Power Exchanges as percentage of Total Short-term Transactions, 2009-10 to 2021-22

Year	Volume of Electricity Transacted through Traders & Power Exchanges (BU)	Total Short-term Transactions of Electricity (BU)	Electricity Transacted through Traders & PXs as % to Total Volume of Short-term
2009-10	33.91	65.9	51.46%
2010-11	43.22	81.56	52.99%
2011-12	51.38	94.51	54.37%
2012-13	59.66	98.94	60.30%
2013-14	65.78	104.64	62.87%
2014-15	63.96	98.99	64.62%
2015-16	70.43	115.23	61.12%
2016-17	74.63	119.23	62.60%
2017-18	86.64	127.62	67.89%
2018-19	100.84	145.20	69.45%
2019-20	86.40	137.16	62.99%
2020-21	106.26	146.01	72.78%
2021-22	140.92	186.75	75.46%

Source: NLDC and Power Exchanges data

The prices of electricity transacted through traders and power exchanges are shown in Table-12 and Figure-9. The weighted average price of electricity transacted through traders and power exchanges declined from ₹ 7.29/kWh and ₹ 7.49/kWh respectively in 2008-09 to ₹ 3.72/kWh and ₹ 4.69/kWh respectively in 2021-22. As may be seen in the Table, over the years the weighted average price of electricity transacted through traders was relatively high when compared with the price of electricity transacted through power exchanges, except in 2021-22 when prices discovered at the power exchanges were comparatively high due to various domestic and global factors.

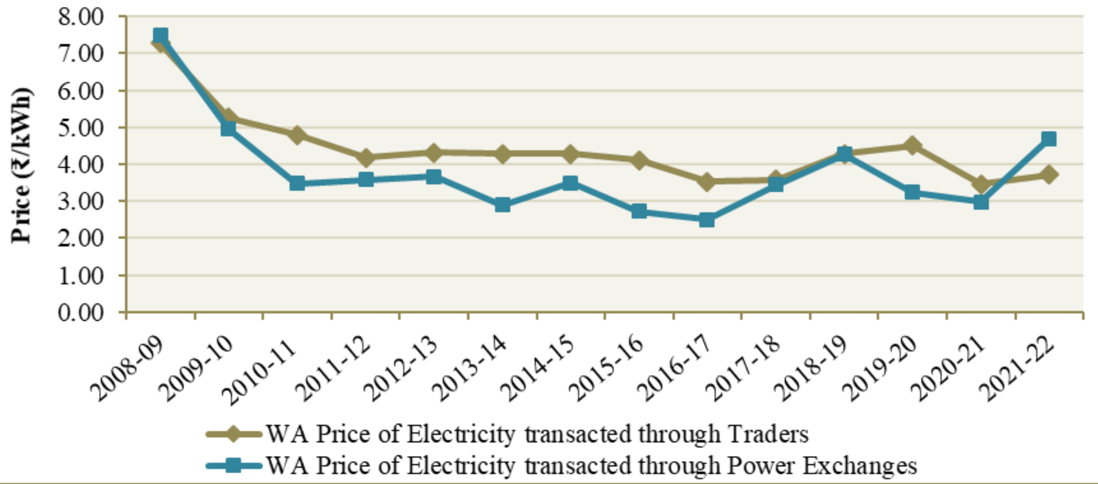
The nature and duration of contract influence the price of electricity, like the delivery of electricity through traders is mostly at state periphery whereas in case of power exchanges the delivery of electricity is at regional periphery. Also, the electricity contracts in case of bilateral transactions take place well in advance (i.e. weekly/monthly upto one year), whereas the electricity contract in case of DAM of power exchanges is one day before.

Table-12: Price of Electricity Transacted through Traders and Power Exchanges, 2008-09 to 2021-22

Year	Weighted Average Price of Electricity transacted through Traders (₹/kWh)	Weighted Average Price of Electricity transacted through Power Exchanges (DAM +G-DAM +TAM +G-TAM +RTM) (₹/kWh)
2008-09	7.29	7.49
2009-10	5.26	4.96
2010-11	4.79	3.47
2011-12	4.18	3.57
2012-13	4.33	3.67
2013-14	4.29	2.90
2014-15	4.28	3.50
2015-16	4.11	2.72
2016-17	3.53	2.50
2017-18	3.59	3.45
2018-19	4.28	4.26
2019-20	4.51	3.24
2020-21	3.47	2.98
2021-22	3.72	4.69

Source: Traders and Power Exchanges data

Figure-9: Price of Electricity Transacted through Traders & Power Exchanges, 2008-09 to 2021-22



The size of the bilateral and power exchange market increased from ₹ 17622 crore in 2009-10 to ₹ 62286 crore in 2021-22, at a CAGR of about 11%. The variation in volume and price affected the size of bilateral and power exchange market. During 2009-10 to 2021-22, the volume of electricity transacted through traders registered a

CAGR of 0.4%, the volume of electricity transacted through power exchanges increased by around 24%. However, the price of electricity transacted through both bilateral and power exchange registered a negative growth of (-) 2.8% and (-) 0.5% respectively.

Table-13: Volume of Electricity Transacted through Traders and Power Exchanges (BU), 2009-10 to 2021-22

Year	Electricity Transacted through Traders (BU)	Weighted Average Price of Electricity transacted through Traders (₹/kWh)	Size of Bilateral Trader market in ₹ Crore	Electricity Transacted through IEX and PXIL (BU)	Weighted Average Price of Electricity transacted through Power Exchanges (₹/kWh)	Size of Power Exchange market in ₹ Crore	Total Size of Bilateral Trader market + Power Exchange market in ₹ Crore
2009-10	26.72	5.26	14055	7.19	4.96	3568	17622
2010-11	27.70	4.79	13268	15.52	3.47	5385	18654
2011-12	35.84	4.18	14979	15.54	3.57	5553	20532
2012-13	36.12	4.33	15624	23.54	3.67	8648	24272
2013-14	35.11	4.29	15061	30.67	2.90	8891	23952
2014-15	34.56	4.28	14801	29.40	3.50	10288	25089
2015-16	35.43	4.11	14557	35.01	2.72	9539	24096
2016-17	33.51	3.53	11844	41.12	2.50	10280	22124
2017-18	38.94	3.59	13970	47.70	3.45	16457	30427
2018-19	47.32	4.28	20255	53.52	4.26	22809	43064
2019-20	29.95	4.51	13516	56.45	3.24	18303	31820
2020-21	26.67	3.47	9245	79.59	2.98	23731	32976
2021-22	39.47	3.72	14688	101.45	4.69	47598	62286

2.1.2 Electricity Transacted through DSM

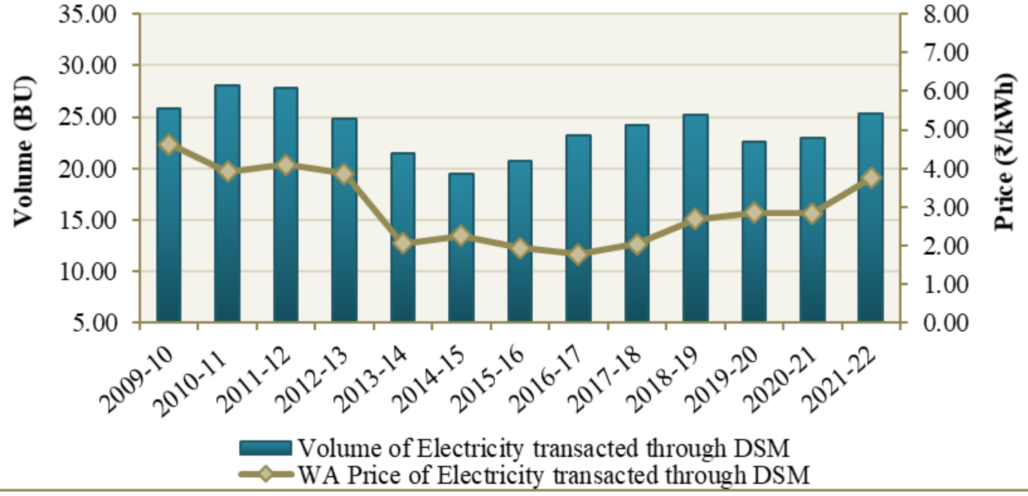
The volume and price of electricity transacted through DSM is shown in Table-14 and Figure-10. The volume of electricity transacted through DSM showed an uneven trend from 2009-10 to 2021-22, however, the volume of DSM as a percentage of total short-term volume declined significantly from its high of 39.2% in 2009-10 to 13.5% in 2021-22. Since the DSM is not a market mechanism, the decline in DSM volume is considered good for the market. So far as the short-term electricity market is concerned, the volume in this segment should be as minimal as possible. The price of DSM plays an important role in ensuring system balance and secure reliable grid operation. As may be seen from the Table-14, the average price of DSM declined from high of ₹4.62/kWh in 2009-10 to ₹3.75/kWh in 2021-22. This may be attributed to the changes in DSM regulations by CERC from time to time.

Table-14: Volume and Price of Electricity Transacted through DSM, 2009-10 to 2021-22

Year	Volume of Electricity Transacted through DSM (BU)	Total Volume of Short-term Transactions (BU)	Volume of DSM as % of Short-term Transactions	Price of Electricity Transacted through DSM (₹/kWh)
2009-10	25.81	65.90	39.2%	4.62
2010-11	28.08	81.56	34.4%	3.91
2011-12	27.76	94.51	29.4%	4.09
2012-13	24.76	98.94	25.0%	3.86
2013-14	21.47	104.64	20.5%	2.05
2014-15	19.45	98.99	19.6%	2.26
2015-16	20.75	115.23	18.0%	1.93
2016-17	23.22	119.23	19.5%	1.76
2017-18	24.21	127.62	19.0%	2.03
2018-19	25.13	145.20	17.3%	2.68
2019-20	22.59	137.16	16.5%	2.85
2020-21	22.91	146.01	15.7%	2.82
2021-22	25.27	186.75	13.5%	3.75

Source: NLDC

Figure-10: Volume and Price of Electricity transacted through DSM, 2009-10 to 2021-22



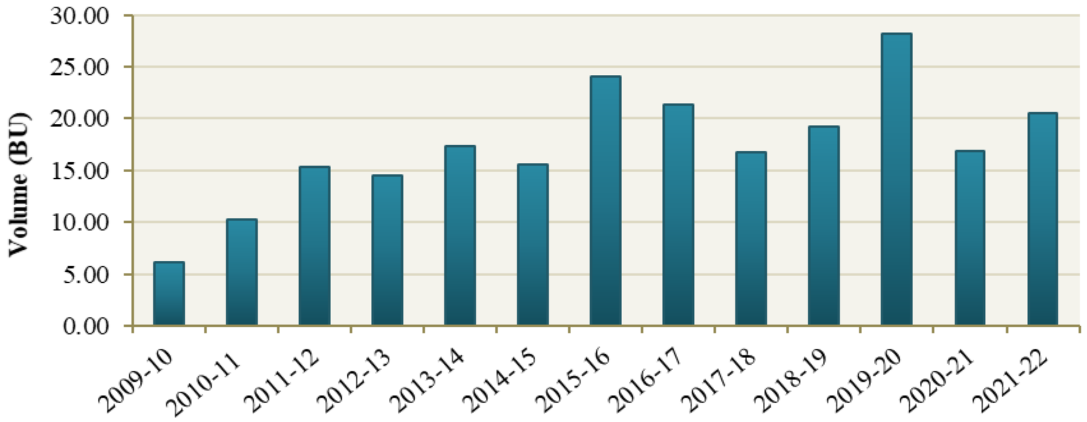
2.1.3 Electricity Transacted Directly between DISCOMs

The volume of electricity transacted directly between DISCOMs is shown in Table-15 and Figure-11. As may be seen from the Table, the volume of electricity transacted directly between DISCOMs increased from 6.19 BU in 2009-10 to 20.56 BU in 2021-22. The volume of electricity transacted directly between DISCOMs as percentage to total volume of short-term transactions of electricity was in the range of 9.4% to 20.9% during the period.

Table-15: Volume of Electricity Transacted Directly between DISCOMs

Year	Volume of Electricity Transacted Directly between DISCOMs (BU)	Total Volume of Short-term Transactions (BU)	Volume of Bilateral Direct as % of total volume of Short-term
2009-10	6.19	65.90	9.4%
2010-11	10.25	81.56	12.6%
2011-12	15.37	94.51	16.3%
2012-13	14.52	98.94	14.7%
2013-14	17.38	104.64	16.6%
2014-15	15.58	98.99	15.7%
2015-16	24.04	115.23	20.9%
2016-17	21.38	119.23	17.9%
2017-18	16.77	127.62	13.1%
2018-19	19.23	145.20	13.2%
2019-20	28.17	137.16	20.5%
2020-21	16.84	146.01	11.5%
2021-22	20.56	186.75	11.0%

Figure-11: Volume of Electricity Transacted Directly between DISCOMs, 2009-10 to 2021-22

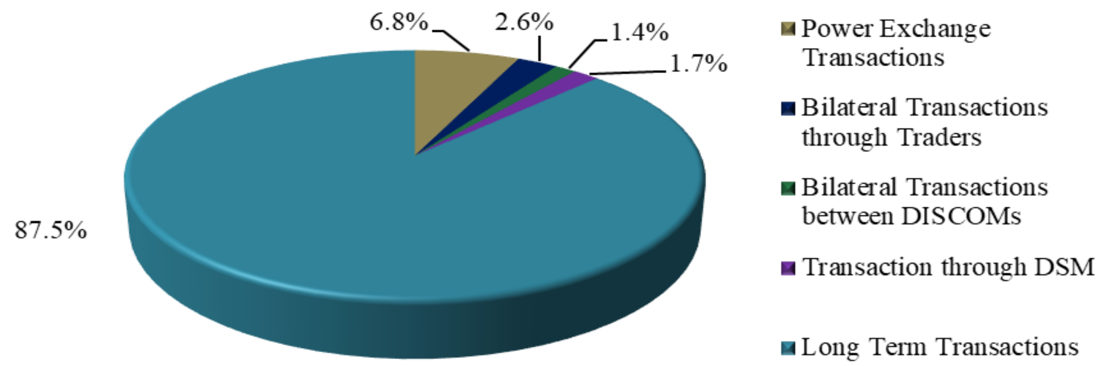


The increasing trend in the volume of electricity transacted directly by DISCOMs over the years is indicative of the fact that the DISCOMs have independently managed the volume of electricity that they require to buy/sell through directly trading between DISCOMs, in addition to buying/selling through trader/Power Exchanges.

3. Monthly Trends in Short-term Transactions of Electricity (April 2021-March 2022)

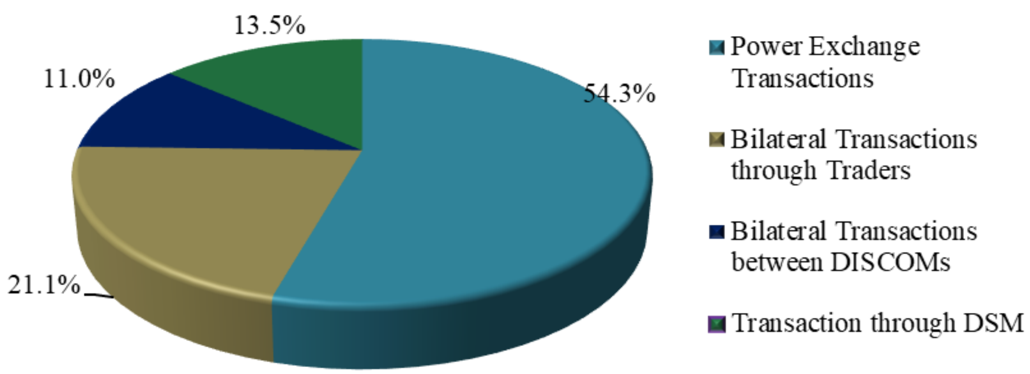
During 2021-22, the share of total short-term transactions in volume terms, including DSM, as a percentage of total electricity generation in the country was about 12.5% (Figure-12).

Figure-12: Share of Market Segments in Total Electricity Generation, 2021-22



The share of different market segments within the total short-term transactions in 2021-22 is shown in the Figure-13 below.

Figure-13: Share of Market Segments in Short Term Transactions, 2021-22



Of the total short-term transactions in 2021-22, the volume of electricity transacted through power exchanges was maximum at 54.3%, followed by bilateral transactions through traders at 21.1%, transactions through DSM at 13.5% and bilateral transactions directly between DISCOMs at 11%.

3.1 Volume of Short-term Transactions of Electricity

The volume of short-term transactions of electricity during different months of 2021-22 with break-up for different market segments is shown in Table-16 and Figure-14.

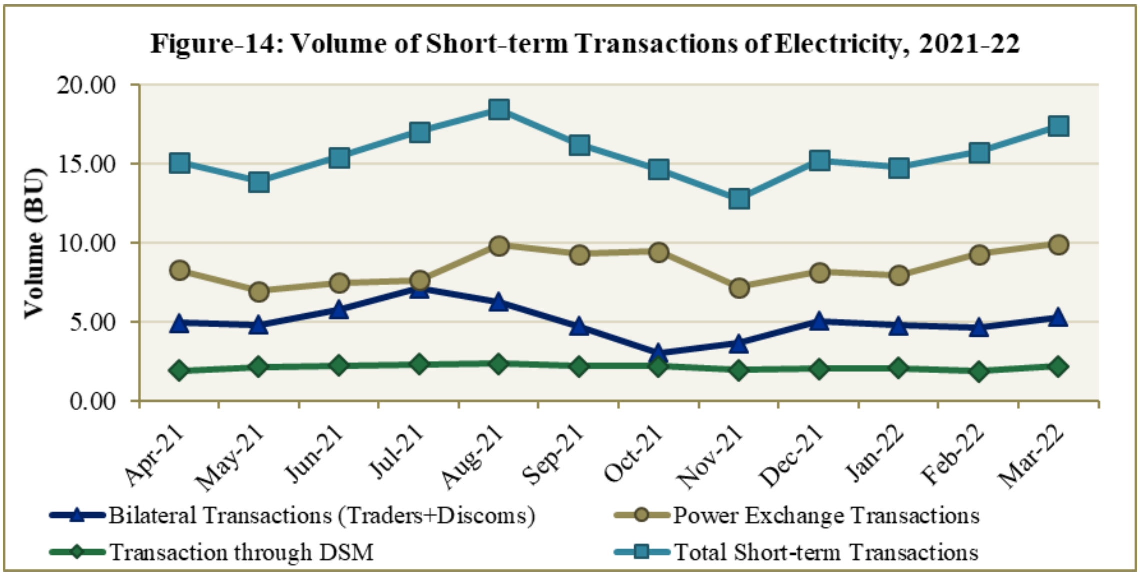
Table-16: Volume of Short-term Transactions of Electricity (BU), 2021-22

Month	Bilateral through Traders	Bilateral between DISCOMs	Total Bilateral	Power Exchange Transactions (DAM +G-DAM +TAM +G-TAM +RTM)	Transa-ctions through DSM	Total Short-term Transac-tions	Total Electricity Generation
Apr-21	3.56	1.36	4.91	8.29	1.90	15.10	127.12
May-21	3.65	1.17	4.82	6.95	2.13	13.91	118.35
Jun-21	4.28	1.51	5.78	7.46	2.20	15.44	123.55
Jul-21	4.86	2.23	7.09	7.63	2.32	17.03	134.95
Aug-21	4.18	2.09	6.27	9.87	2.32	18.46	137.88
Sep-21	2.84	1.90	4.74	9.30	2.17	16.21	122.73
Oct-21	1.57	1.46	3.03	9.45	2.17	14.65	122.28
Nov-21	1.85	1.79	3.64	7.20	1.95	12.79	108.10
Dec-21	3.10	1.95	5.05	8.16	2.01	15.22	118.75
Jan-22	2.90	1.86	4.76	7.95	2.07	14.78	121.04
Feb-22	2.92	1.71	4.63	9.27	1.84	15.74	117.54
Mar-22	3.76	1.53	5.29	9.94	2.19	17.41	139.56
Total	**39.47**	**20.56**	**60.02**	**101.45**	**25.27**	**186.75**	**1491.85**

Source: NLDC & CEA

As may be observed from Figure-14, there is a cyclical trend in the monthly volume of short-term transactions of electricity and a similar trend is observed in the power exchange transactions. The volume of transactions increases during peak summers from May to July and then gradually declines from August onwards, before starting to rise again from November onwards mainly due to heating and lighting loads.

As expected, there is no cyclical trend in the transactions through DSM since these transactions do not move by seasonal variations.



The volume of short-term transactions of electricity as percentage of total electricity generation varied from 11.7% and 13.4% during April 2021 to March 2022 (Table-17).

Table-17: Volume of Short-term Transactions of Electricity as % of Total Electricity Generation, 2021-22

Period	Short-term Transactions as % of Total Electricity Generation
Apr-21	11.9%
May-21	11.7%
Jun-21	12.5%
Jul-21	12.6%
Aug-21	13.4%
Sep-21	13.2%
Oct-21	12.0%
Nov-21	11.8%
Dec-21	12.8%
Jan-22	12.2%
Feb-22	13.4%
Mar-22	12.5%

As on 31.3.2022, there were a total of 43 inter-state trading licensees; of which, 29 trading licensees actively undertook short-term electricity trading during the year 2021-22 (Table-18).

The volume of electricity transacted through traders/trading licensees (inter-state bilateral transactions and transactions through Power Exchanges) has been analysed using the Herfindahl-Hirschman Index (HHI) for measuring competition among the traders (Table-18). Increase in the HHI generally indicates a decrease in competition and an increase of market power, and vice-versa. HHI value below 0.15 indicates un-concentration of market power, the value between 0.15 to 0.25 indicates moderate concentration, the value above 0.25 indicates high concentration of market power. The HHI, based on the volume of electricity transacted through traders during 2021-22 was 0.2431, which indicates moderate concentration of market power among the traders. As compared to 2020-21 with HHI value of 0.2161, the level of market concentration has increased in 2021-22.

Table-18: Share of Electricity Transacted by Traders and HHI, 2021-22

Sr No	Name of the Trading Licensee	Share of Electricity traded by Licensees	Herfindahl-Hirschman Index (HHI)
1	PTC India Ltd.	44.84%	0.2011
2	Tata Power Trading Company (P) Ltd.	11.52%	0.0133
3	NTPC Vidyut Vyapar Nigam Ltd.	11.49%	0.0132
4	Adani Enterprises Ltd.	8.07%	0.0065
5	Manikaran Power Ltd.	7.34%	0.0054
6	Arunachal Pradesh Power Corporation (P) ltd	3.56%	0.0013
7	GMR Energy Trading Ltd.	3.25%	0.0011
8	Kreate Energy (I) Pvt. Ltd.	2.42%	0.0006
9	Essar Electric Power Development Corp. Ltd.	1.82%	0.0003
10	Instinct Infra & Power Ltd.	0.84%	0.0001
11	JSW Power Trading Company Ltd	0.84%	0.0001
12	National Energy Trading & Services Ltd.	0.79%	0.0001
13	Knowledge Infrastructure Systems (P) Ltd	0.76%	0.0001
14	RPG Power Trading Company Ltd.	0.62%	0.0000
15	Statkraft Markets Pvt. Ltd.	0.51%	0.0000
16	Abja Power Pvt. Ltd.	0.27%	0.0000
17	Greenko Energies Pvt Ltd	0.21%	0.0000
18	Refex Energy Ltd.	0.16%	0.0000
19	NHPC Ltd.	0.12%	0.0000
20	Saranyu Power Trading Pvt. Ltd.	0.12%	0.0000
21	Shubheksha Advisors Pvt. Ltd.	0.10%	0.0000
22	NLC India Ltd.	0.08%	0.0000
23	Ambitious Power Trading Company Ltd.	0.07%	0.0000

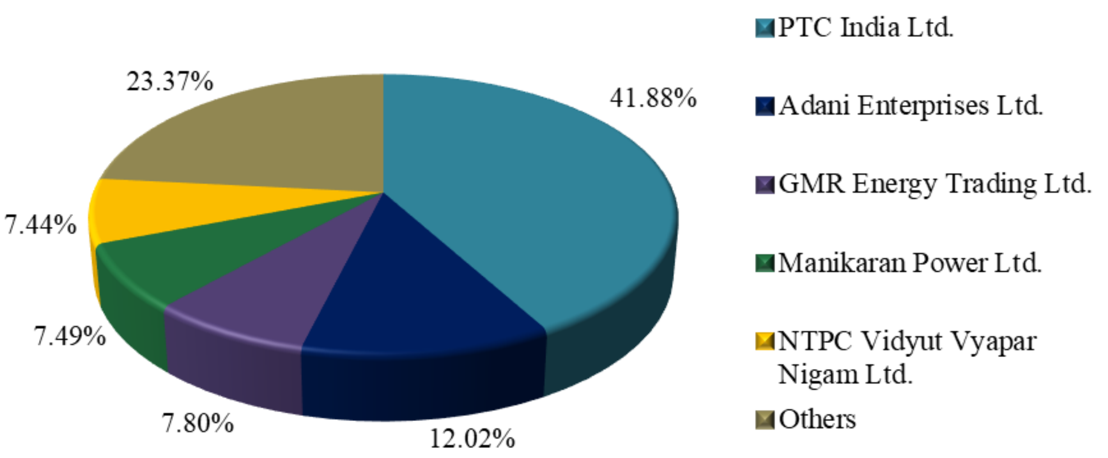
24	Gita Power & Infrastructure Pvt. Ltd.	0.07%	0.0000
25	Shree Cement Ltd.	0.06%	0.0000
26	Customized Energy Solutions India (P) Ltd.	0.03%	0.0000
27	Altilium Energie Pvt. Ltd.	0.01%	0.0000
28	Phillip Commodities India (P) Ltd.	0.01%	0.0000
29	Instant Venture Pvt. Ltd.	0.0001%	0.0000
Total Volume		**100.00%**	**0.2431**
Share of the Top 5 Trading		**83.26%**	

Note: Percentage share in total volume traded by Licensees in 2021-22 is computed based on the volume which includes the volume traded by inter-state trading licensees through bilateral and power exchanges.

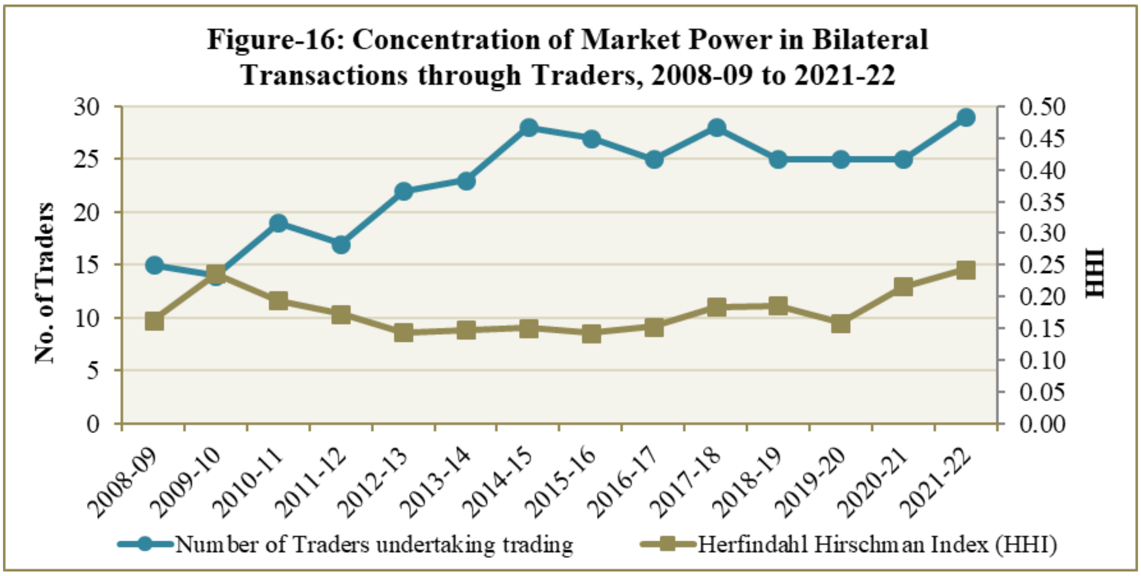
Source: Information submitted by Trading Licensees.

The percentage share of electricity transacted by major traders in the total volume of electricity transacted by all the traders is shown in Figure-15.

Figure-15: Share of Electricity transacted by Traders, 2021-22



The concentration of market power based on the volume of electricity transacted through traders and the number of traders is shown in Figure-16. As may be observed from the figure, the number of traders who were undertaking trading bilaterally or through power exchanges or through both, increased from 15 in 2008-09 to 29 in 2021-22.



3.2 Price of Short-term Transactions of Electricity

The monthly trends in price of short-term transactions of electricity are shown in Table-19 and Figure-17&18. The price analysis is mainly based on the average price of DSM and the weighted average price of other short-term transactions of electricity. The price of bilateral trader transactions represents the price of electricity transacted through traders. The trend in price of electricity transacted through traders (bilateral trader transactions) are discussed separately for total transactions as well as for the transactions undertaken during Round the Clock (RTC), Peak and Off-peak periods.

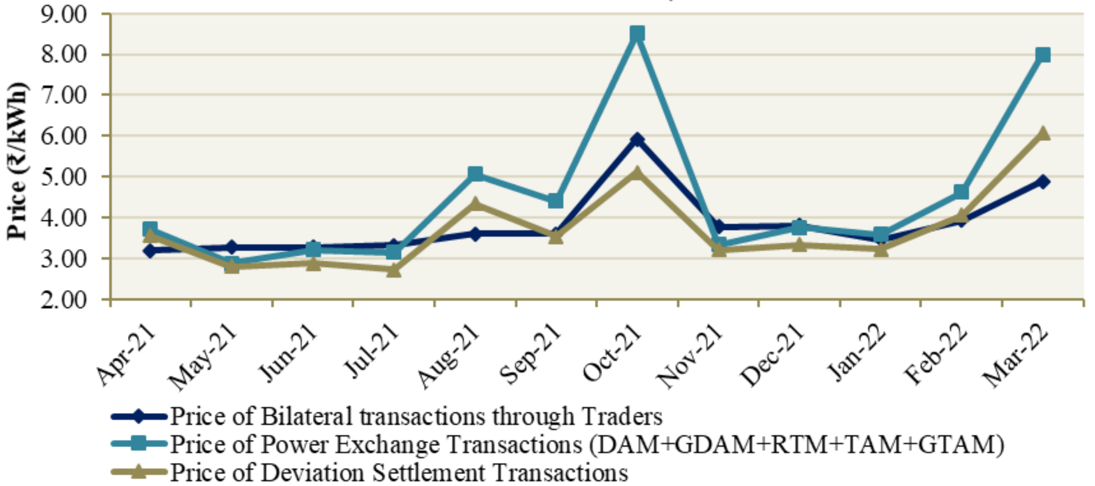
Table-19(a): Price of Short-term Transactions of Electricity (₹/kWh), 2021-22

Month	Bilateral through Traders				Power Exchange	DSM
	RTC	Peak	Off-peak	Weighted Average	Weighted Average	All India Grid
Apr-21	3.13	4.29	3.55	3.20	3.71	3.56
May-21	3.15	4.69	3.70	3.27	2.89	2.81
Jun-21	3.17	4.99	3.92	3.28	3.22	2.88
Jul-21	3.27	4.61	3.86	3.32	3.16	2.73
Aug-21	3.54	4.61	4.11	3.60	5.07	4.35
Sep-21	3.59	4.61	3.85	3.61	4.41	3.55
Oct-21	6.03	7.50	4.89	5.93	8.51	5.12
Nov-21	3.83	-	3.14	3.79	3.35	3.22
Dec-21	3.73	-	4.74	3.81	3.77	3.35

Jan-22	3.40	5.97	3.92	3.47	3.59	3.24
Feb-22	3.87	4.80	4.43	3.94	4.63	4.06
Mar-22	4.91	5.00	4.57	4.89	7.99	6.07

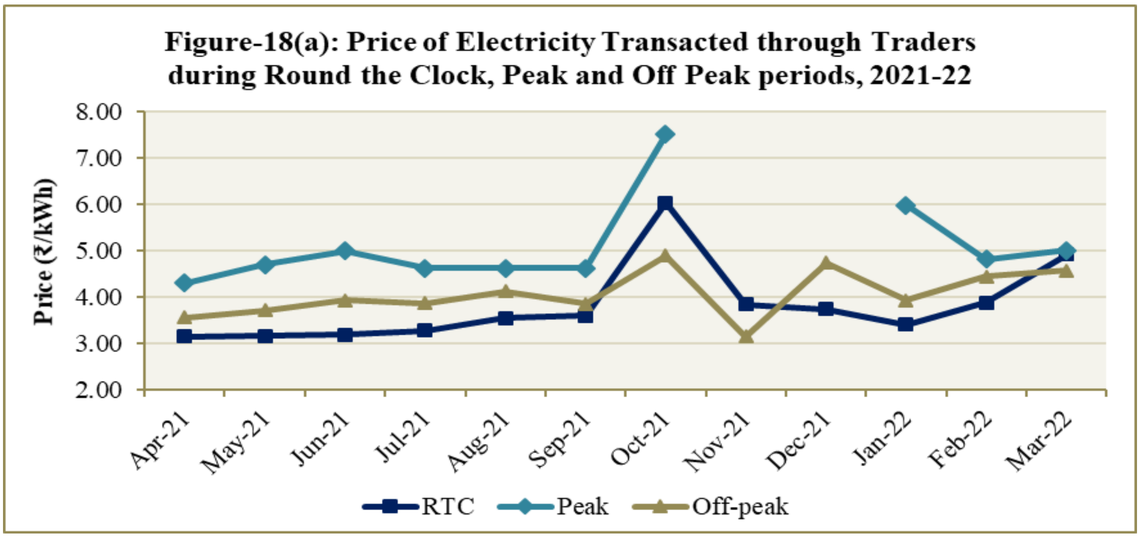
(-) Indicates no transactions during the month.

Figure-17: Comparison of Prices of Bilateral, Power Exchange and DSM Transactions, 2021-22



It can be observed from the above figure that the price of electricity transacted through power exchanges witnessed sharp increase during the period from August to October 2021 and again in March 2022. While the domestic supply constraints due to excessive rainfall, planned shutdown, etc., were attributed as the main reasons for the price rise during August to October 2021, demand-side pressures mainly due to early onset of summers, coupled with certain domestic and external factors which affected fuel supply were some of the key reasons for price rise in March 2022. Moreover, gradual opening of economic & commercial activities after the slowdown due to pandemic & lockdown condition, also led to price rise during these months.

The trend in price of electricity transacted by traders during RTC, Peak and Off-peak periods are shown in Table-19(a) & Figure-18(a). There is no price mentioned for electricity transacted during peak for some of the months in 2021-22 because there was no volume of electricity transacted exclusively during the peak period in these months.



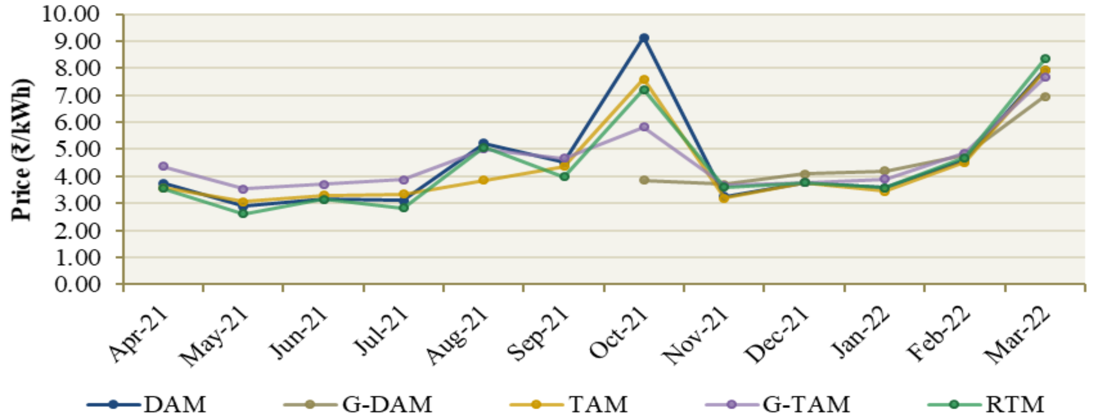
The trend in price of electricity transacted through Power Exchanges in the various market segments are shown in Table-19(b) & Figure-18(b). Similar trend can be observed in the price movement in all the market segments. The price of electricity transacted across all market segments, witnessed sharp increase during the period from August to October 2021 (except G-DAM as it was introduced in October 2021) and again in March 2022. In general, the prices in G-DAM and G-TAM have been higher than the prices in DAM & TAM segments respectively. This is due to the green attributes of RE power sold through G-DAM & G-TAM on the power exchanges. The prices discovered in RTM segment have been lower than the prices in DAM as the trading takes place closer to delivery, except in March 2022 when there were supply constraints and high demand.

Table-19(b): Price of Power Exchange Transactions of Electricity (₹/kWh), 2021-22

Month	Power Exchange					
	DAM	G-DAM	TAM	G-TAM	RTM	Weighted Average
Apr-21	3.75	-	3.57	4.36	3.55	3.71
May-21	2.90	-	3.07	3.54	2.61	2.89
Jun-21	3.17	-	3.31	3.71	3.15	3.22
Jul-21	3.11	-	3.35	3.87	2.84	3.16
Aug-21	5.23	-	3.85	5.02	5.07	5.07
Sep-21	4.51	-	4.36	4.66	3.98	4.41
Oct-21	9.15	3.87	7.60	5.82	7.21	8.51
Nov-21	3.26	3.71	3.19	3.66	3.60	3.35
Dec-21	3.76	4.10	3.78	3.76	3.77	3.77

Jan-22	3.58	4.20	3.45	3.90	3.57	3.59
Feb-22	4.61	4.78	4.51	4.85	4.69	4.63
Mar-22	7.95	6.96	7.92	7.66	8.34	7.99

Figure-18(b): Price of Electricity Transacted through Power Exchanges in different market segments, 2021-22

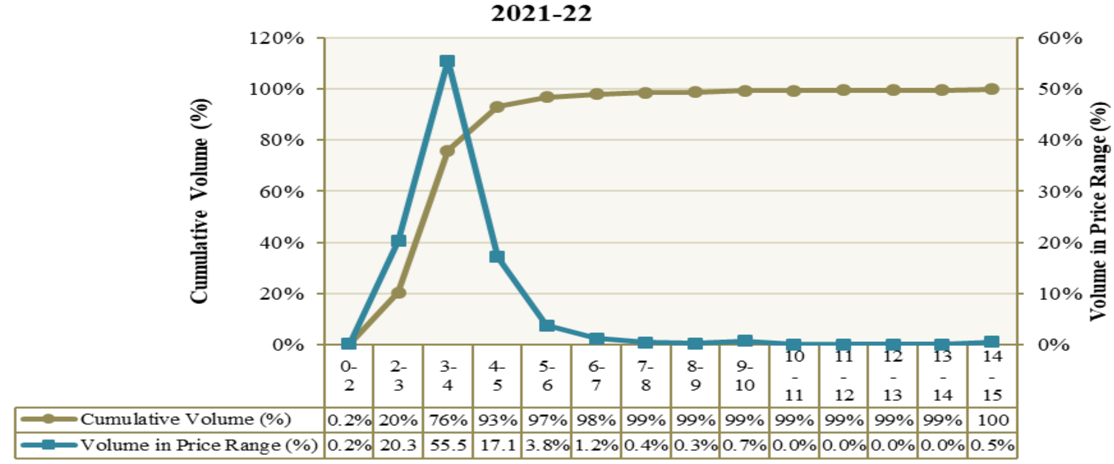


3.3 Volume of Electricity Transacted in various Price Slabs

Volume of electricity transacted in various price slabs is shown for bilateral trader segment and power exchange segment separately. In case of power exchanges, DAM, G-DAM and RTM segments have been considered separately.

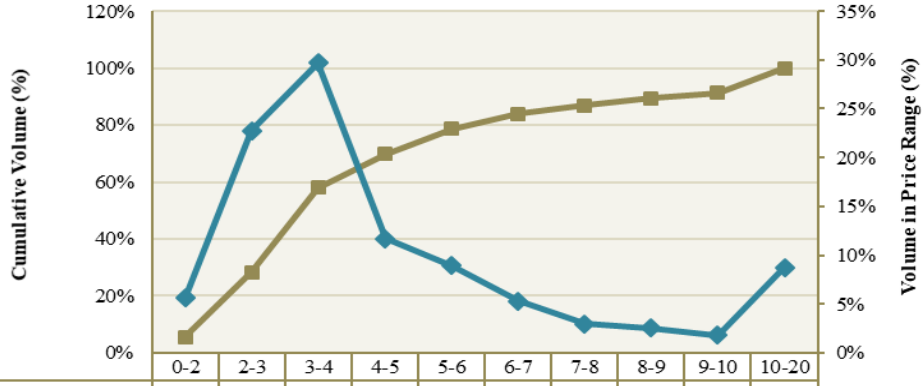
Volume of bilateral transactions at different price slabs in 2021-22 is depicted in Figure-19. The figure shows that about 93% of the volume of electricity was transacted through traders at less than ₹ 5/kWh and 99% of the volume was transacted through traders at less than ₹ 10/kWh.

Figure-19: Volume of Bilateral Transaction at different Price Slabs, 2021-22



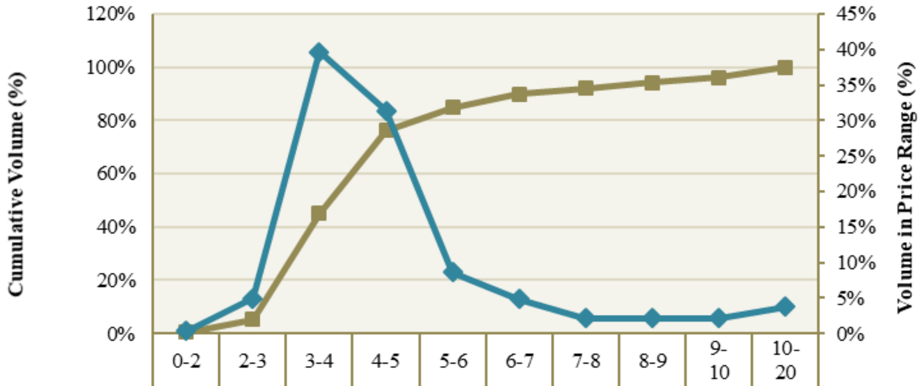
The volume of electricity transacted in IEX at different price slabs in DAM, G-DAM and RTM segments during 2021-22 are depicted in Figure-20(a), 20(b) and 20(c) respectively. The figure shows that 70% of the volume of electricity in DAM was transacted at less than ₹ 5/kWh and 91% of the volume was transacted at less than ₹ 10/kWh. In case of G-DAM, where transactions in IEX started from October 2021 onwards, about 76% of the volume of electricity was transacted at less than ₹ 5/kWh and 96% of the volume was transacted at less than ₹ 10/kWh. Similarly, under RTM segment, 78% of the volume of electricity was transacted at less than ₹ 5/kWh and 93% of the volume was transacted at less than ₹ 10/kWh.

Figure-20 (a): Volume of IEX Transactions in Day Ahead Market at different Price Slabs, 2021-22

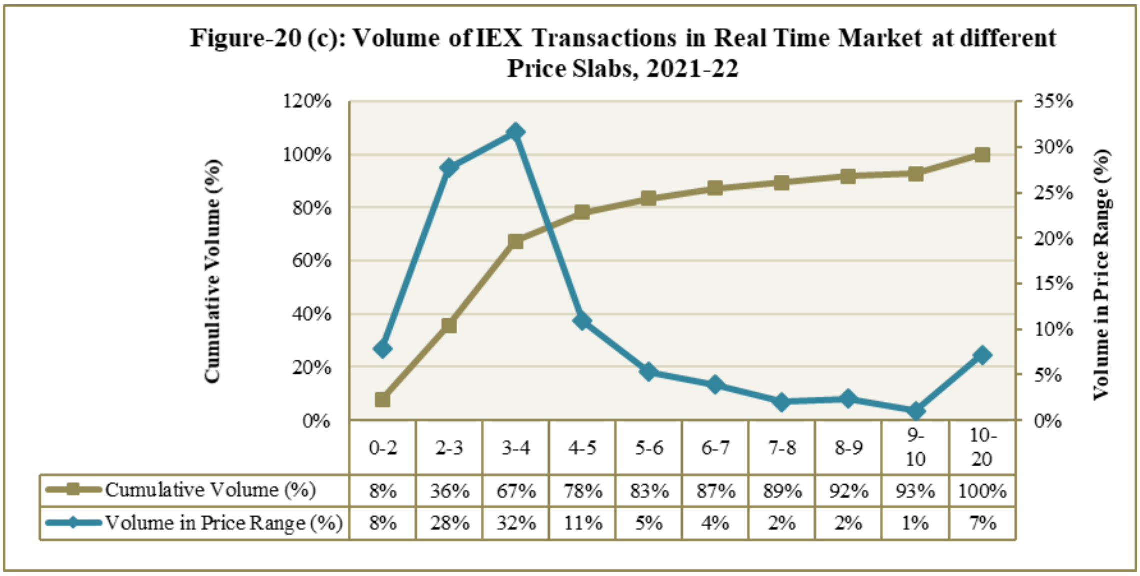


	0-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-20
Cumulative Volume (%)	6%	28%	58%	70%	79%	84%	87%	89%	91%	100%
Volume in Price Range (%)	6%	23%	30%	12%	9%	5%	3%	3%	2%	9%

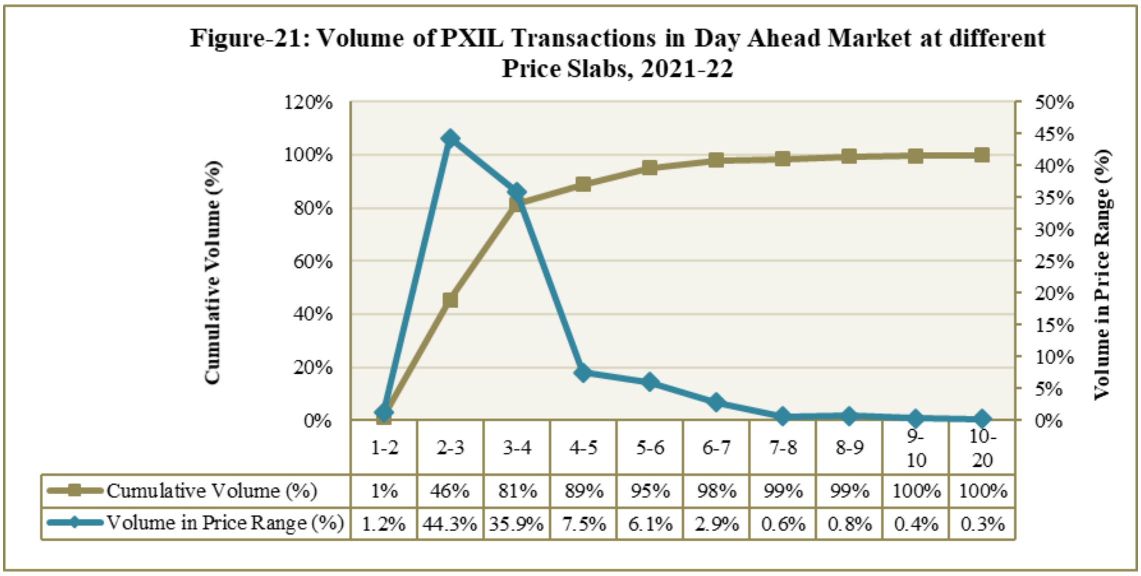
Figure-20 (b): Volume of IEX Transactions in Green Day Ahead Market at different Price Slabs, 2021-22



	0-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-20
Cumulative Volume (%)	0%	5%	45%	76%	85%	90%	92%	94%	96%	100%
Volume in Price Range (%)	0%	5%	40%	31%	9%	5%	2%	2%	2%	4%



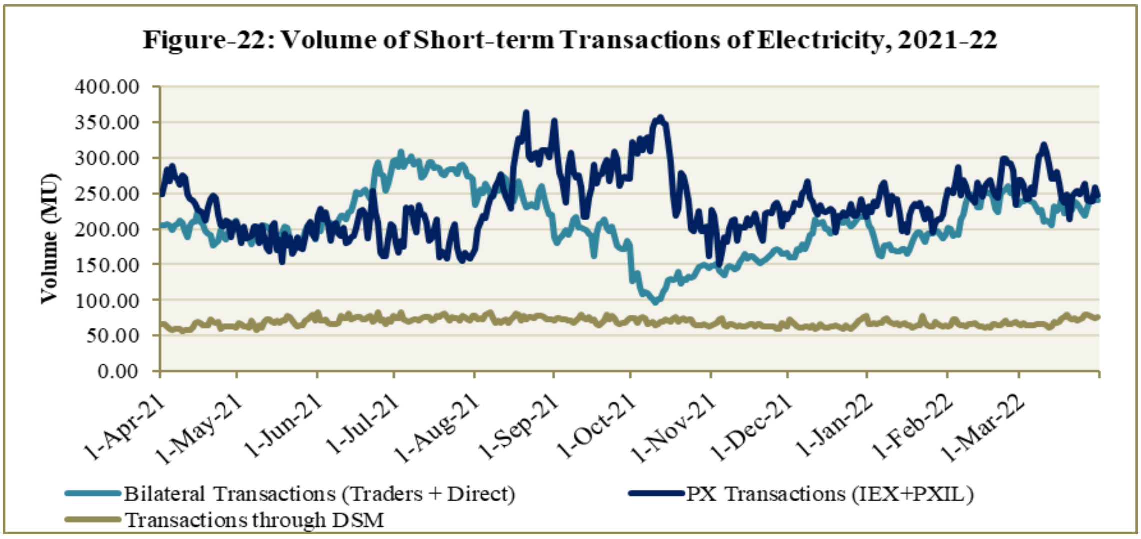
Volume of PXIL transactions at different price slabs in DAM is depicted in Figure-21. The figure shows that 89% of the volume of electricity in DAM was transacted at less than ₹ 5/kWh and about 99.7% of the volume was transacted at less than ₹ 10/kWh. There were no transactions through PXIL in G-DAM and RTM during 2021-22.



4. Daily Trends in Short-term Transactions of Electricity (1st April 2021 to 31st March 2022)

4.1 Volume of Short-term Transactions of Electricity

Trends in daily volume of short-term transactions are shown in Figure-22. It can be observed from the figure that the volume of electricity transacted through power exchanges witnessed a sharp increase in August and October 2021, while bilateral transactions remained subdued during this period. However, from late January 2022 onwards, volume started to increase both through power exchanges and bilateral (traders and directly between DISCOMs).



4.2 Price of Short-term Transactions of Electricity

Price and its volatility in the daily price of short-term transactions of electricity through power exchanges and DSM have been analysed in this section. Volatility has been computed using the historic volatility formula (see Annexure-III for formula).

4.2.1 Price and its volatility in Power Exchanges

The weighted average price of electricity transacted through IEX in DAM, G-DAM and RTM segments with their respective volatility levels are shown in Figure-23(a), 23(b) and 23(c) respectively. Volatility in the price of electricity transacted through IEX has been computed using daily data for 2021-22 and it works out to be 17.35% in case of DAM, 16.39% in G-DAM and 25.28% in RTM.

Figure-23(a): Price and its Volatility in DAM on IEX during 2021-22

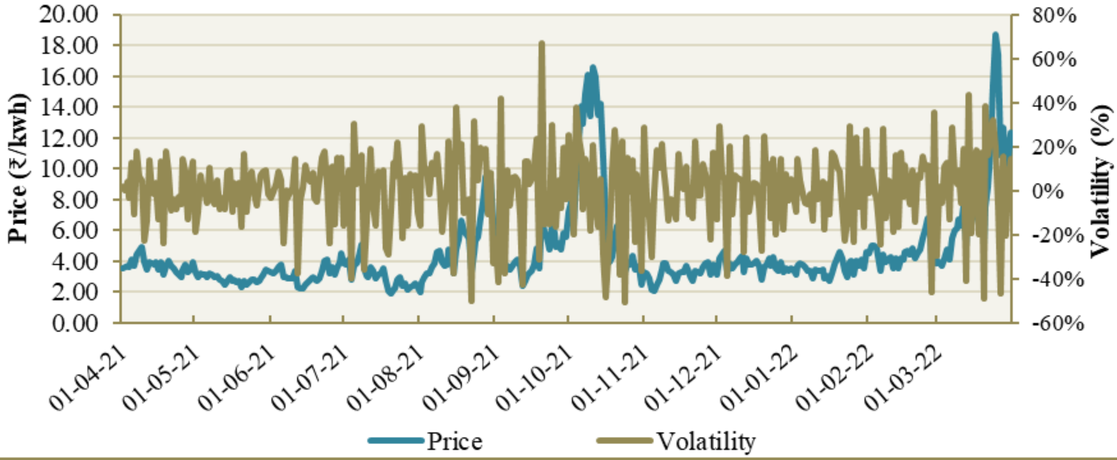
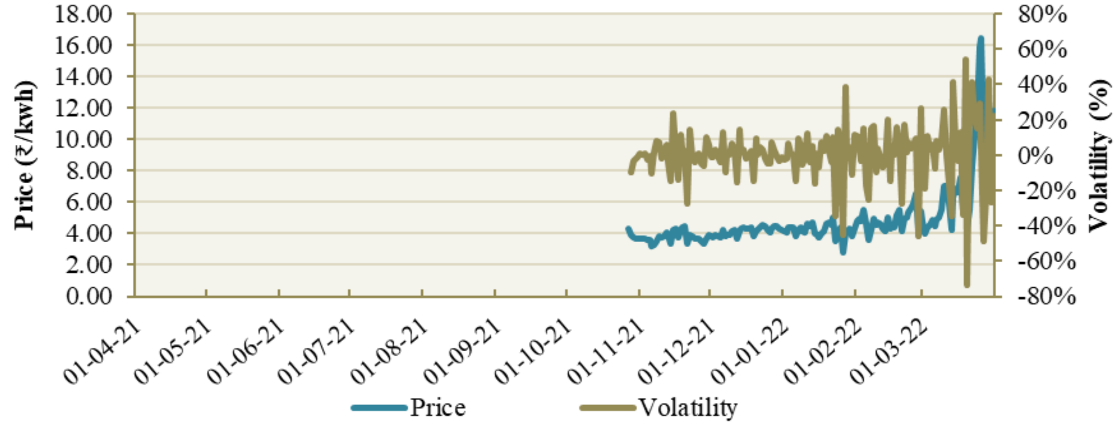
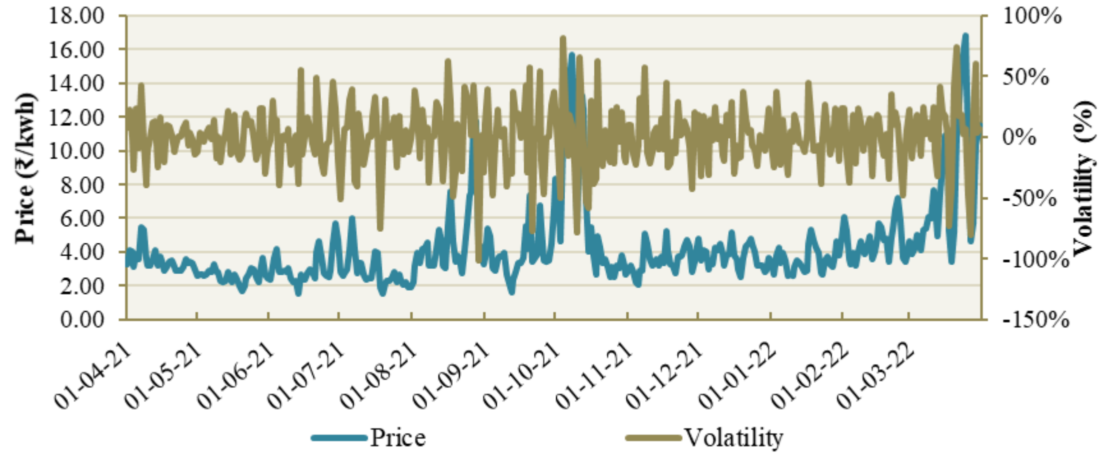


Figure-23(b): Price and its Volatility in G-DAM on IEX during 2021-22



Note: G-DAM was introduced from 27th October 2021

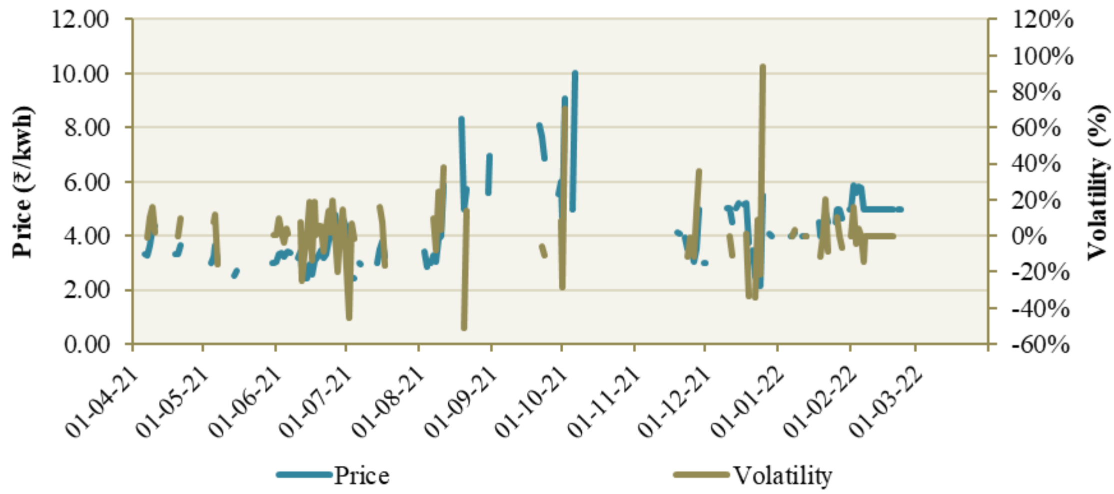
Figure-23(c): Price and its Volatility in RTM on IEX during 2021-22



Note: RTM was introduced from 1st June 2020

The weighted average price of electricity transacted through PXIL in DAM and its volatility is shown in Figure-24. Volatility in the price of electricity transacted through PXIL has been computed using daily data for 2021-22 and it works out to be 18.81% in case of DAM. There were no transactions through PXIL in G-DAM and RTM during 2021-22.

Figure-24: Price and its Volatility in DAM on PXIL during 2021-22

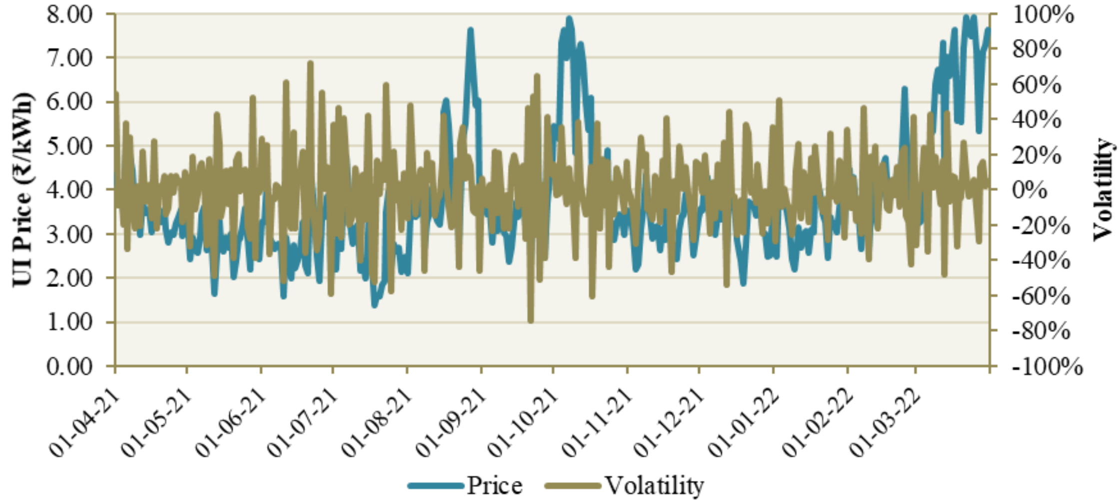


As may be seen from above, the prices and the volatility in the price of electricity transacted through IEX and PXIL was high during 2021-22 mainly on account of mismtach between demand and supply.

4.2.2 *Price and its volatility in DSM*

The average price of electricity transacted through DSM and its volatility is shown in Figure-25. Volatility in the price of electricity transacted through DSM has been computed using daily data for 2021-22 and it works out to be 23.36%.

Figure-25: Price and its Volatility in DSM during 2021-22



Since the nature of transactions through DSM are different from transactions through power exchanges, the volatility in the price of electricity transacted through DSM is higher (23.36%) than the volatility in the price of electricity transacted through power exchanges in DAM (17.35% in IEX and 18.81% in PXIL).

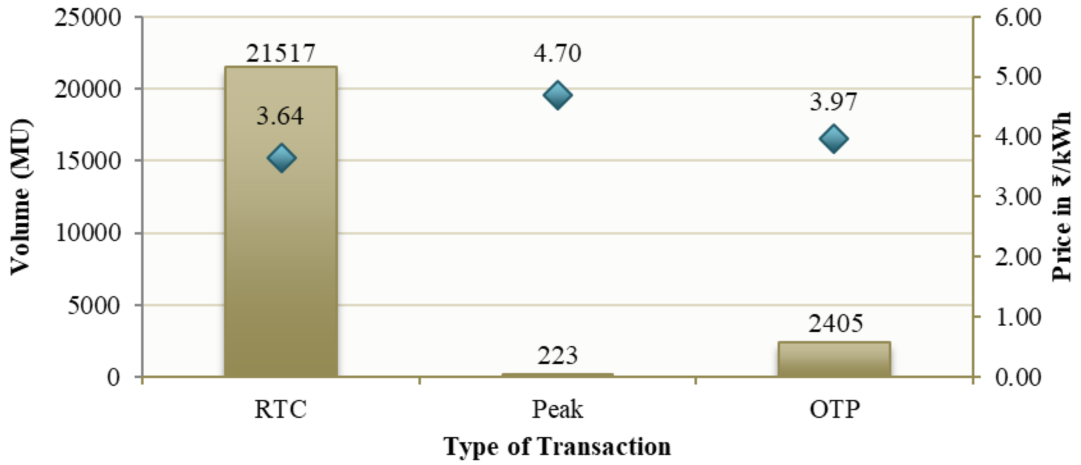
5. Time of the Day Variation in Volume and Price of Electricity Transacted through Traders and Power Exchanges

In this section, time of the day variation in volume and price of electricity transacted through traders has been illustrated for RTC (Round the Clock), Peak period and other than RTC & Peak period. Time of the day variation in volume and price of electricity transacted through power exchanges is shown block-wise. Price of electricity transacted through power exchanges is discussed both region-wise and block-wise.

5.1 Time of the Day Variation in Volume and Price of Electricity Transacted through Traders

Time of the day variation in volume and price of electricity transacted through bilateral traders' transactions during 2021-22 is shown in Figure-26. The volume of electricity transacted through traders represent inter-state transactions, i.e., excluding banking transactions. Time of the day variation in volume is shown during RTC (Round the Clock), Peak period and OTP (other than RTC & Peak period). Of the total volume, about 89% was transacted during RTC followed by 10% during OTP and 1% during peak period. It can be observed from the figure that the share of volume transacted during peak period is low at about 1% of the total transactions. It can also be observed that the weighted average price during Peak period was higher (₹ 4.70/kWh), as compared to prices during RTC (₹ 3.64/kWh) and OTP (₹ 3.97/kWh).

Figure-26: Volume and Price of Electricity Transacted through Traders during RTC, Peak and OTP, 2021-22



5.2 Time of the Day Variation in Volume and Price of Electricity Transacted through Power Exchanges

Time of the day variation in volume and price of electricity transacted under DAM, G-DAM and RTM at IEX during 2021-22 are shown block-wise in Figure-27(a), 27(b) and 27(c) respectively. It may be observed from the figure that high price in DAM and RTM segment was witnessed during morning and evening peak hours. In case of G-DAM, it can be observed that the market clearing volume increases during day time, i.e., solar hours. With increase in supply during the day time, prices in G-DAM segment remained low, whereas high prices were observed during morning an evening peak when corresponding supply of RE power was low.

Figure-27(a): Block-wise Market Clearing Volume and Price in DAM on IEX during 2021-22

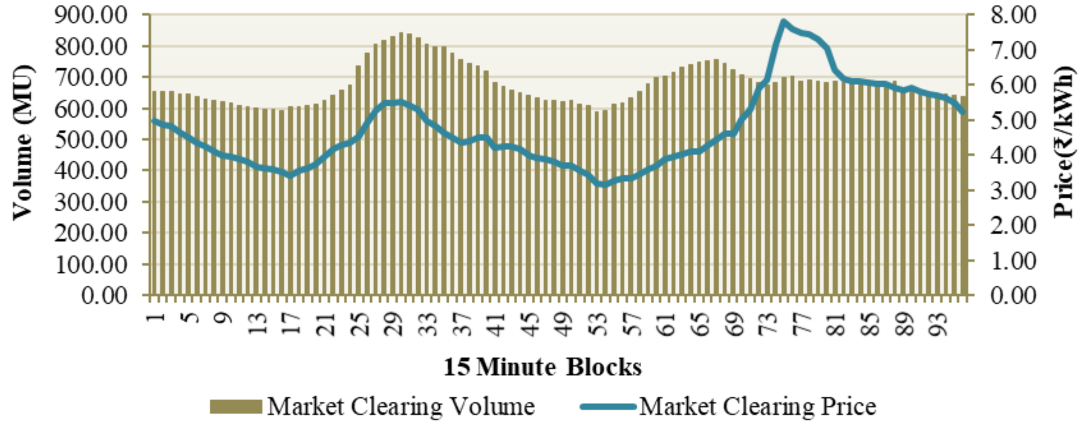


Figure-27(b): Block-wise Market Clearing Volume and Price in G-DAM on IEX during 2021-22

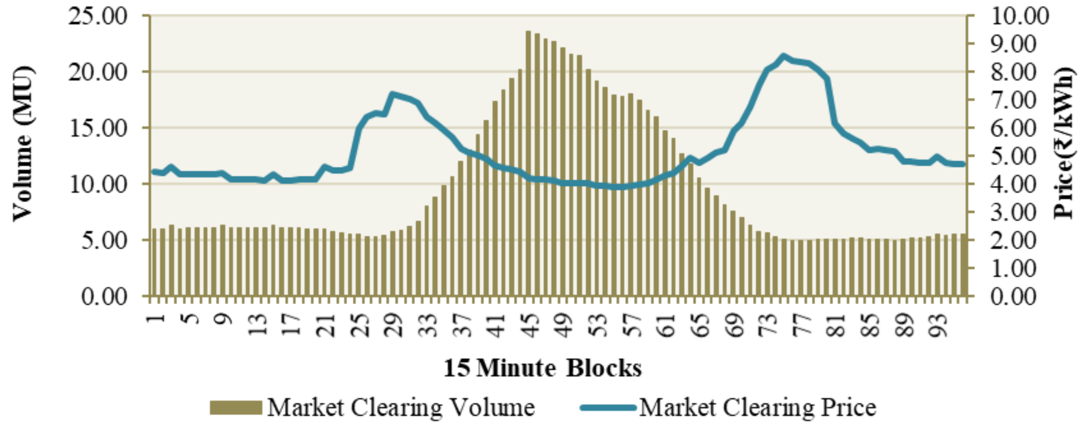
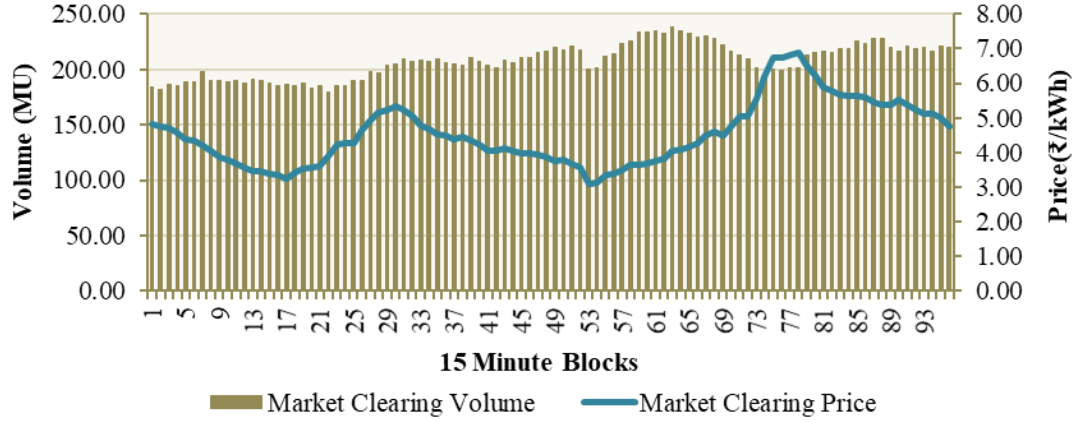
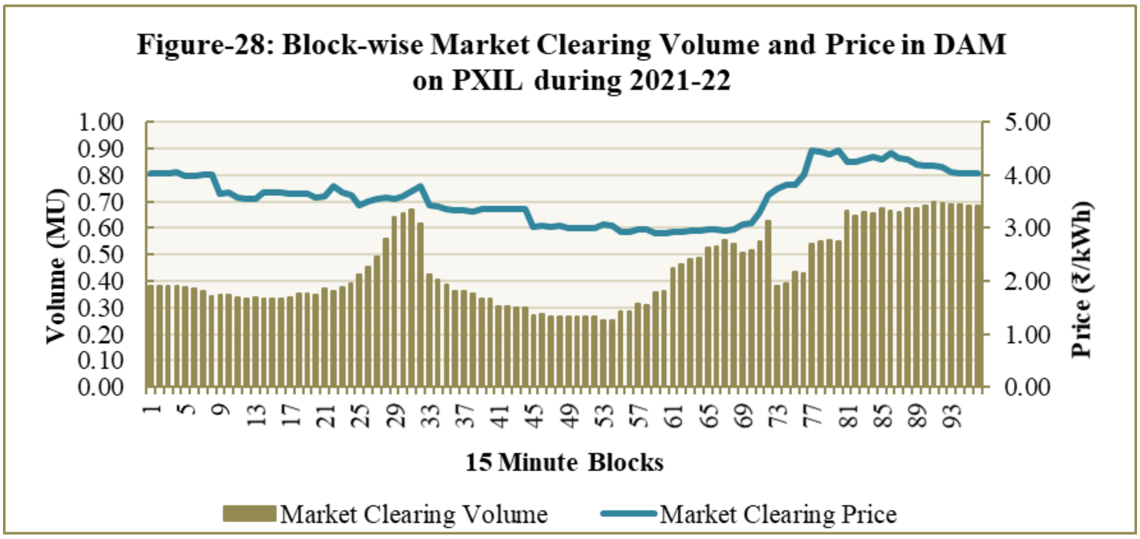


Figure-27(c): Block-wise Market Clearing Volume and Price in RTM on IEX during 2021-22



Time of the day variation in volume and price of electricity transacted through DAM in PXIL during 2021-22 is shown block-wise in Figure-28. There was no transaction through G-DAM and RTM in PXIL during 2021-22.



Region-wise and hour-wise prices of electricity transacted through IEX in DAM, G-DAM and RTM are shown in Figure-29(a), 29(b) and 29(c) respectively. It can be observed that during 2021-22, the price of electricity in all the regions was almost similar in IEX, which is indicative of very few instances of congestion. Only in case of RTM, in the Southern region, due to high demand for electricity particularly during morning and evening period, the prices were relatively higher than the other regions.

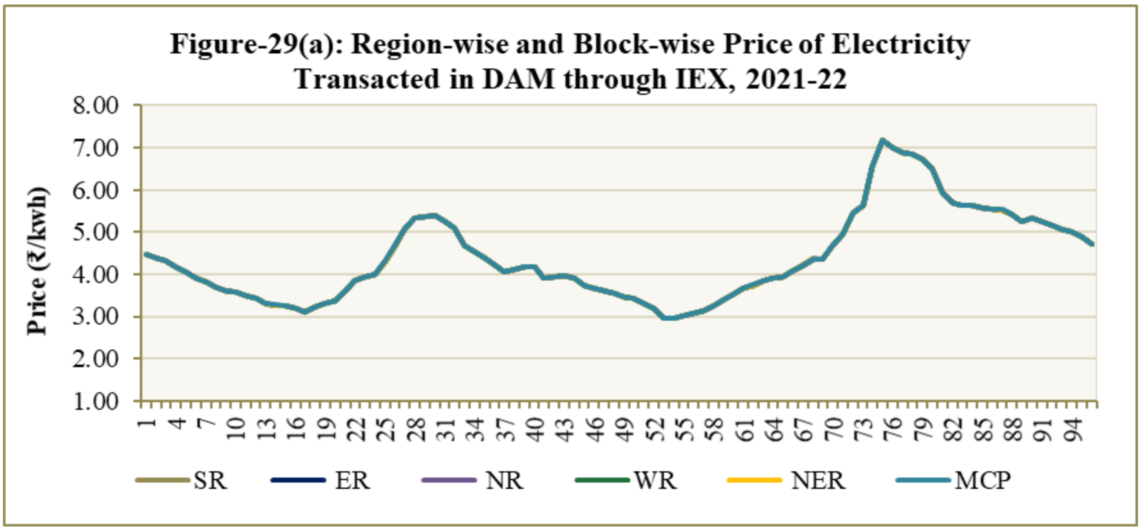


Figure-29(b): Region-wise and Block-wise Price of Electricity Transacted in G-DAM through IEX, 2021-22

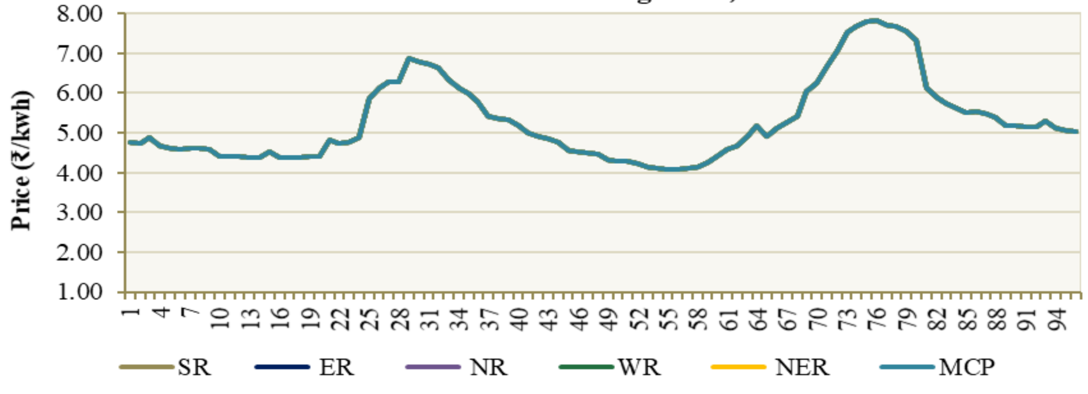
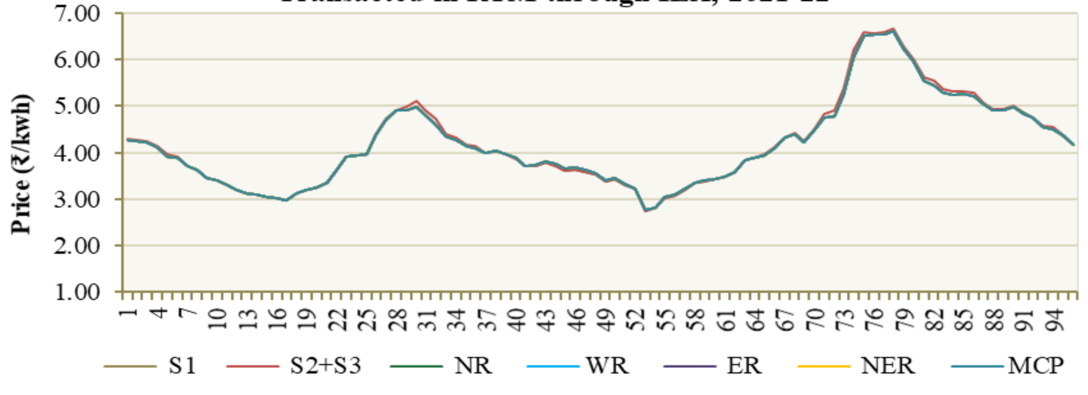
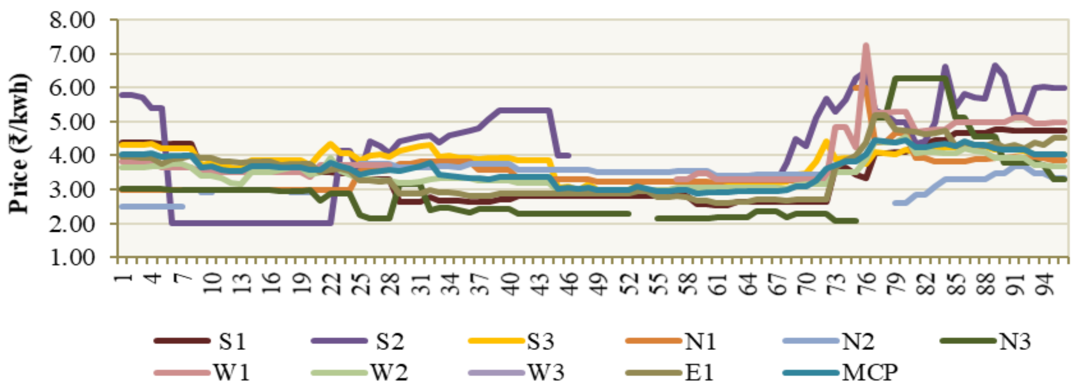


Figure-29(c): Region-wise and Block-wise Price of Electricity Transacted in RTM through IEX, 2021-22



Region-wise and hour-wise prices of electricity transacted through PXIL in DAM are shown in Figure-30. Though no consistent trend was observed in price in different regions, price of electricity in northern region was relatively low when compared with the prices in other regions, except for a few blocks at late evening. There was no transaction in G-DAM and RTM through PXIL during 2021-22.

Figure-30: Region-wise and Block-wise Price of Electricity Transacted in DAM through PXIL, 2021-22



6. Trading Margin Charged by Trading Licensees

During the year 2004-05, when trading started through licensees, the licensees voluntarily charged 5 paise/kWh or less as the trading margin for bilateral transactions. However, trading margin increased in 2005 and the weighted average trading margin charged by the licensees went up to 10 paise/kWh during April to September 2005 period. This has necessitated to fix trading margin for inter-state trading of electricity. The trading margin was fixed at 4 paise/kWh, vide CERC (Fixation of Trading Margin) Regulations notification dated 26.01.2006. As a result of these trading margin regulations, the licensees charged trading margin of 4 paise or less from 26.01.2006 onwards until revised Trading Margin Regulations, 2010 came into existence on 11.01.2010 (Table-20 & Figure-31).

Based on feedback and experience gained from 2006 Regulations and considering various risks associated with the electricity trading business, CERC revised the trading margin in 2010. As per the CERC (Fixation of Trading Margin) Regulations, 2010, the trading licensees are allowed to charge trading margin up to 7 paise/kWh in case the sale price exceeds ₹ 3/kWh, and 4 paise/kWh where the sale price is less than or equal to ₹ 3/kWh.

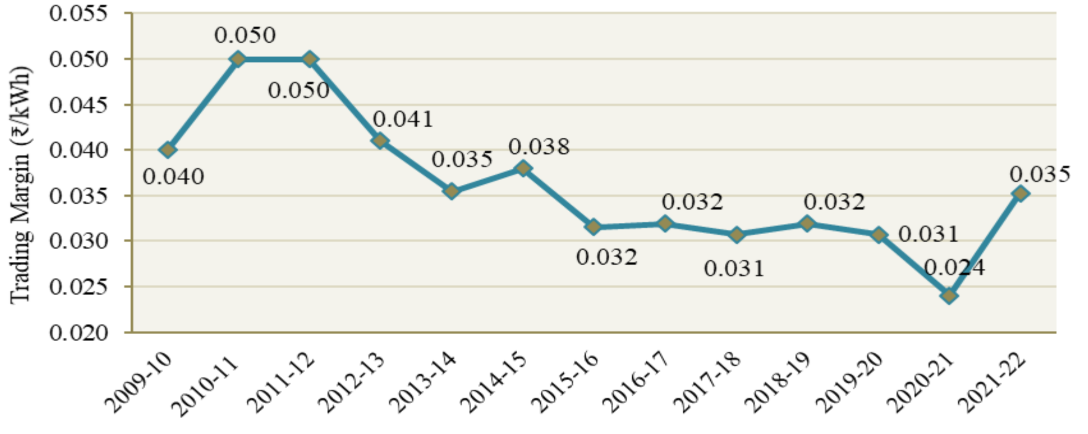
For increasing the volume of trading, some of the trading licensees misunderstood the intention of the trading margin regulations and charged negative trading margin for some of the transactions. Keeping this in view and to avoid negative trading margin, the Commission, in the CERC (Procedure, Terms and Conditions for grant of trading licence and other related matters) Regulations, 2020 has prescribed the trading margin of not less than zero (0.0) paise/kWh and not exceeding seven (7.0) paise/kWh w.e.f. 31st January, 2020. In these regulations, the applicability of trading margin has been clearly specified separately for transactions under (a) short-term contracts, (b) long-term contracts, (c) banking contracts, (d) back-to-back contracts and (e) cross border trade of electricity. The trading licensees have been charging the trading margin as per the regulations. Due to stiff competition among the trading licensees, the trading margin charged by the trading licensees was always less than the ceiling margin allowed in the trading margin regulations. The new trading margin regulations restrict the trading licensees from charging negative trading margin, i.e., less than zero (0.0) paise/kWh. The weighted average trading margin charged by the trading licensees for bilateral transactions during 2009-10 to 2021-22 is provided in Table-20 and Figure-31.

Table -20: Trading Margin Charged by Trading Licensees, 2009-10 to 2021-22

Period	Trading Margin (₹/kWh)
2009-10	0.040
2010-11	0.050
2011-12	0.050
2012-13	0.041
2013-14	0.035
2014-15	0.038
2015-16	0.032
2016-17	0.032
2017-18	0.031
2018-19	0.032
2019-20	0.031
2020-21	0.024
2021-22	0.035

Note 1: Weighted Average Trading Margin is computed based on all Inter-state Trading Transactions excluding Banking Transactions

Figure-31: Trading Margin Charged by Trading Licensees, 2009-10 to 2021-22



It can be observed from the above figure that the trading margin charged by the trading licensees in general witnessed a downward trend over the years except for 2021-22. This may be attributed to the increasing competition among the trading licensees.

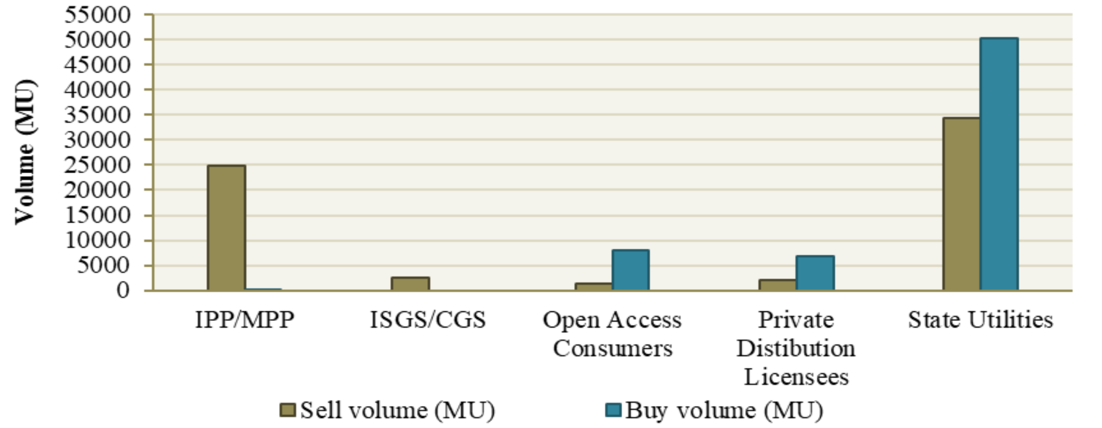
7. Open Access Consumers on Power Exchanges

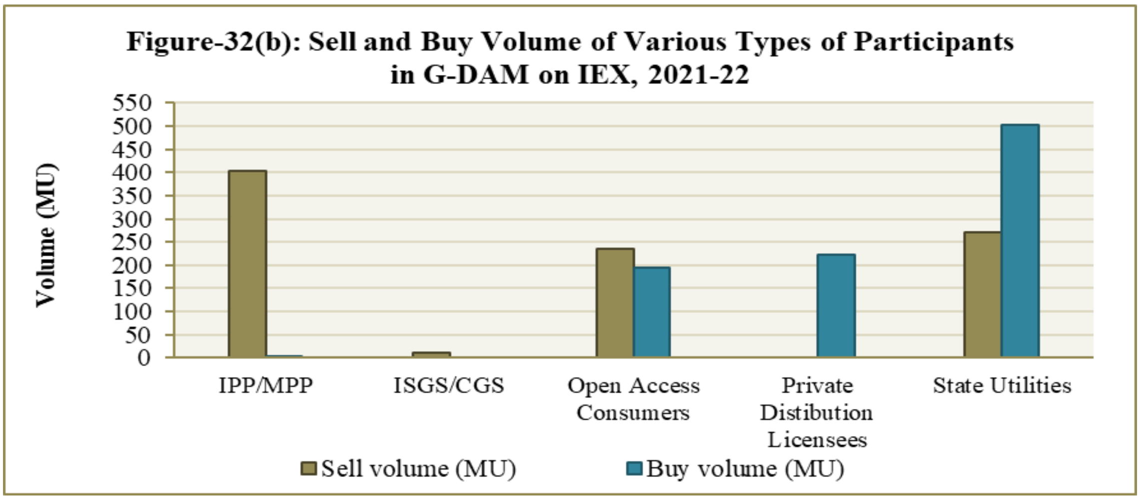
This section discusses the various types of participants in power exchanges and provides analysis of open access consumers in DAM, RTM and G-DAM segments of power exchanges (Open Access consumers include Industrial Consumers and Captive Power Plants)

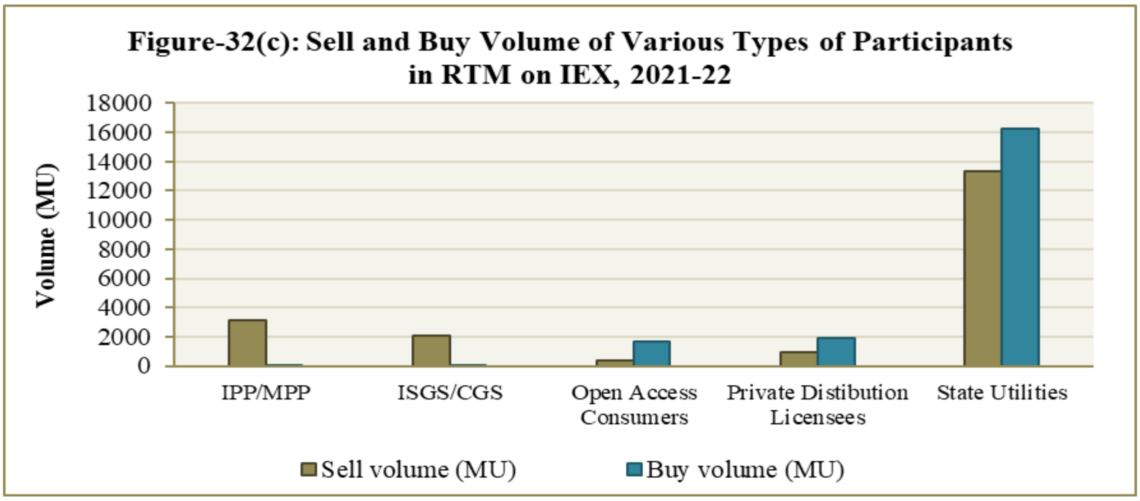
7.1 Types of Participants in Power Exchanges

As shown in Figure-32 (a), 32(b) and 32(c) during the year 2021-22, there were five types of participants at IEX under DAM, G-DAM and RTM. In case of DAM, the major sellers of electricity at IEX were state utilities and independent power producers, while the major buyers of electricity were state utilities followed by open access consumers and private distribution licensees {Figure 32 (a)}. In case of G-DAM, the major sellers of electricity were independent power producers, followed by state utilities and open access consumers, while the major buyers of electricity were state utilities followed by private distribution licensees and open access consumers {Figure 32 (b)}. In case of RTM, state utilities followed by independent power producers were the major sellers, and on the buyers' side state utilities and private distribution licensees has the highest share {Figure 32 (c)}.

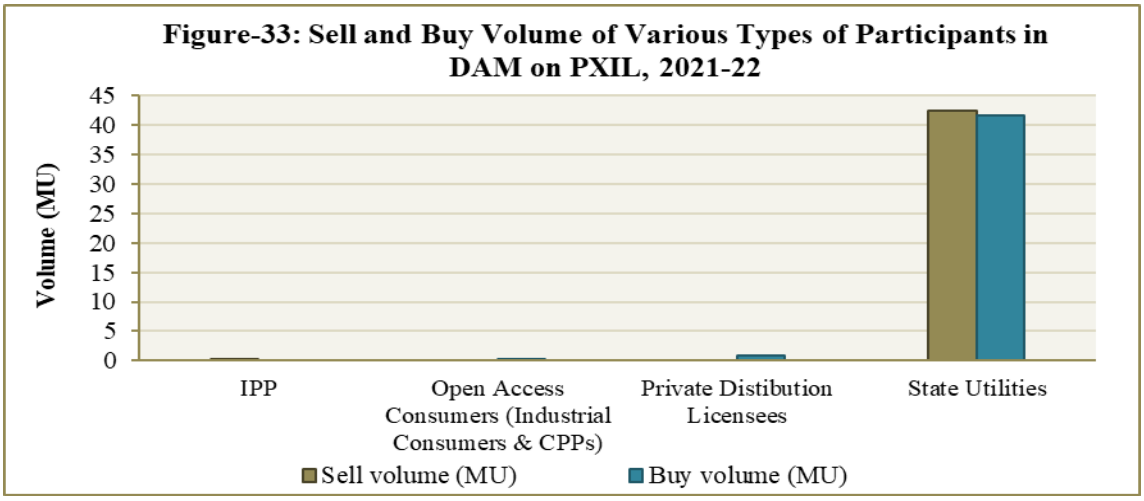
Figure-32(a): Sell and Buy Volume of Various Types of Participants in DAM on IEX, 2021-22







There were 4 types of participants at PXIL in DAM during 2021-22, as shown in Figure-33. It can be observed from the figure that major sellers as well as buyers of electricity at PXIL in DAM were state utilities constituting more than 97% of the total trade. There was no trade in G-DAM and RTM at PXIL during the year 2021-22.



7.2 Analysis of Open Access Consumers on Power Exchanges

The year 2010-11 witnessed collective open access transactions, which marked a significant development in procurement of power by the industrial consumers through power exchanges. The number of Open Access (OA) Consumers in both IEX and PXIL increased from 825 and 170 respectively in 2010-11 to 4967 and 661 respectively in 2021-22 (Table-21). During the period, the percentage of open access consumers in total portfolios varied between 90% to 96% in IEX, whereas the percentage varied between 16% to 90% in PXIL. The number of OA consumers in IEX increased at a CAGR of 18%, and at 13% in case of PXIL. Though there is an increasing trend in the number of OA consumers in PXIL, the percentage of open access consumers in total portfolio of PXIL declined significantly from the high of about 90% in 2010-11 to 17% in 2021-22.

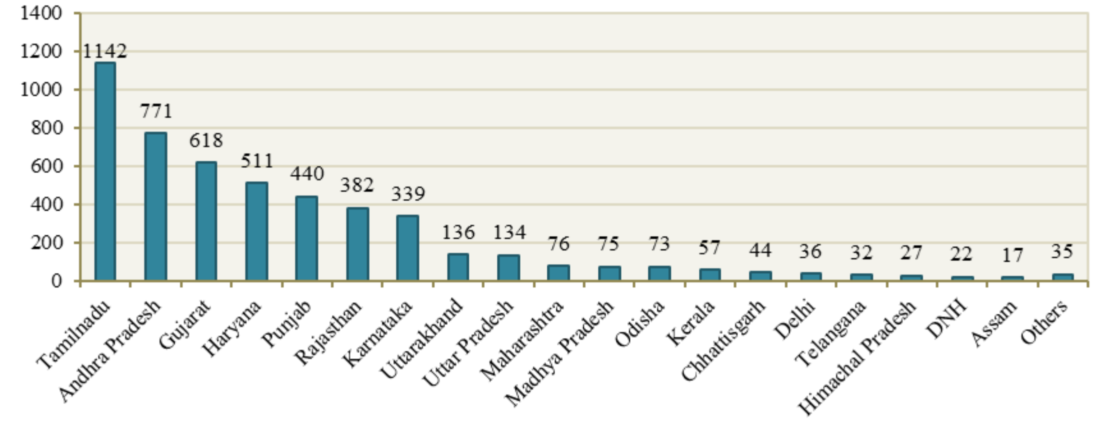
Table-21: Number of Open Access Consumers in Power Exchanges, 2010-11 to 2021-22

Year	IEX			PXIL		
	No. of Open Access Consumers	Total No. of Portfolios	% of Open Access Consumers	No. of Open Access Consumers	Total No. of Portfolios	% of Open Access Consumers
2010-11	825	863	95.6%	170	190	89.5%
2011-12	968	1073	90.2%	231	465	49.7%
2012-13	2110	2227	94.7%	336	379	88.7%
2013-14	2958	3083	95.9%	473	1399	33.8%
2014-15	3269	3407	95.9%	517	1779	29.1%
2015-16	3650	3796	96.2%	527	2924	18.0%
2016-17	4071	4281	95.1%	542	3277	16.5%
2017-18	4248	4502	94.4%	559	3422	16.3%
2018-19	4362	4633	94.2%	588	3657	16.1%
2019-20	4555	4857	93.8%	615	3780	16.3%
2020-21	4768	5114	93.2%	632	3805	16.6%
2021-22	4967	5376	92.4%	661	3923	16.8%

Note: Status as on 31^{st} March of respective year.

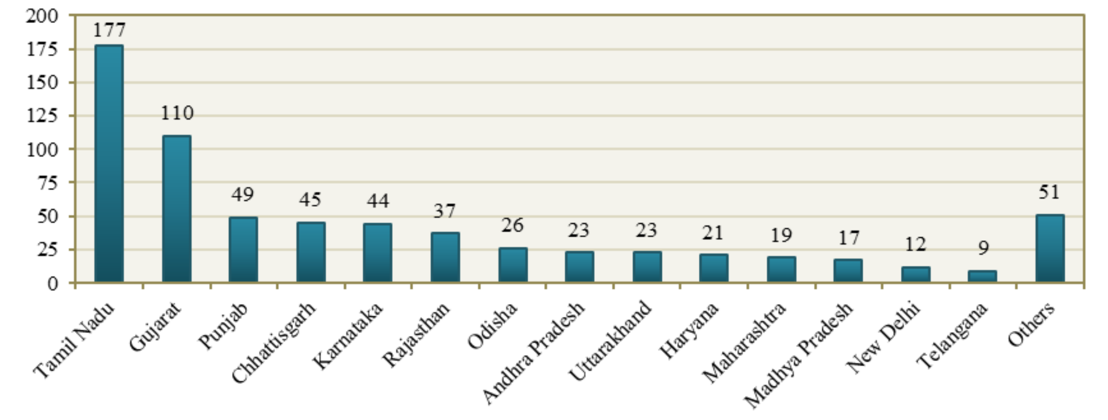
In 2021-22, there were about 4967 OA consumers at IEX. These consumers were mostly located in Tamil Nadu, Andhra Pradesh, Gujarat, Haryana and Punjab, (Figure-34). The weighted average price of electricity bought by OA consumers at IEX (₹3.20/kWh) was lower when compared to the weighted average price of total electricity transacted through IEX (₹ 4.73/kWh).

Figure-34: State-wise Number of Open Access Consumers in IEX, March 2022



In 2021-22, there were about 661 OA consumers at PXIL. These consumers were mostly located in Tamil Nadu, Gujarat, Punjab, Chhattisgarh, and Karnataka (Figure-35). The weighted average price of electricity bought by open access consumers at PXIL was higher (₹ 4.99/kWh) when compared to the weighted average price of total electricity transacted through PXIL (₹ 3.68/kWh).

Figure-35: State-wise Number of Open Access Consumers in PXIL, March 2022



Annual comparison between purchase volume of OA consumers and total volume in DAM of IEX and PXIL during 2010-11 to 2021-22 is shown in Table-22(a). As may be seen in the Table below, the volume of electricity procured by OA consumers as a percentage of total volume transacted in IEX has come down significantly in both the power exchanges (IEX and PXIL). In case of IEX, during 2010-11 to 2021-22 the volume of electricity procured by OA consumers as a percentage of total volume transacted varied between 12% to 61%, while in PXIL it was between 0.1% to 58% during the same period.

Table-22 (a): Volume of Purchase by Open Access Consumers in Day Ahead Market of Power Exchanges, 2010-11 to 2021-22

Year	IEX			PXIL		
	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Participation	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Participation
2010-11	4056.51	11800.58	34.4%	92.72	1740.17	5.3%
2011-12	6275.30	13798.88	45.5%	306.58	2057.60	14.9%
2012-13	10410.13	22374.78	46.5%	263.41	687.96	38.3%
2013-14	17575.17	28924.84	60.8%	503.03	1106.42	45.5%
2014-15	12084.18	28140.72	42.9%	102.95	340.77	30.2%
2015-16	20284.49	34066.52	59.5%	78.78	136.84	57.6%
2016-17	23999.77	39830.66	60.3%	44.06	248.54	17.7%
2017-18	14728.37	44925.11	32.8%	5.70	730.48	0.8%
2018-19	11219.07	50136.03	22.4%	21.02	86.40	24.3%
2019-20	14452.80	49126.10	29.4%	9.96	46.63	21.3%
2020-21	14383.05	60376.03	23.8%	0.24	241.19	0.1%
2021-22*	7888.34	65143.03	12.1%	0.03	42.61	0.1%

*OAC Purchase volume in case of PXIL includes drawal by CPPs.

The purchase volume by OA consumers vis-à-vis total volume in case of G-DAM, which became operational in power exchanges from October 2021, is given in Table-22(b). As may be seen from the table, the volume of electricity procured by OA consumers as a percentage of total volume transacted in IEX varied between 11% to 34% in 2021-22, while no electricity was procured by OA consumers through PXIL in G-DAM segment.

Table-22(b): Volume of Purchase by Open Access Consumers in Green Day Ahead Market of Power Exchanges, 2021-22

Year	IEX			PXIL		
	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Partici-pation	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Partici-pation
Oct-21	6.58	19.41	33.90%	0.00	0.00	-
Nov-21	27.48	149.47	18.38%	0.00	0.00	-
Dec-21	28.15	157.20	17.91%	0.00	0.00	-
Jan-22	66.07	198.35	33.31%	0.00	0.00	-
Feb-22	43.83	191.20	22.92%	0.00	0.00	-
Mar-22	22.88	204.82	11.17%	0.00	0.00	-
Total	**194.99**	**920.45**	**21.18%**	**0.00**	**0.00**	**-**

Note: G-DAM is operational on the IEX from October 2021 and on PXIL from December 2021

The purchase volume by OA consumers vis-à-vis total volume in case of RTM, which became operational in power exchanges from June 2020, is given in Table-22(c). As may be seen from the Table, the volume of electricity procured by OA consumers as a percentage of total volume transacted in IEX is around 8%, while no electricity was procured by OA consumers through PXIL in RTM segment.

Table-22(c): Volume of Purchase by Open Access Consumers in Real Time Market of Power Exchanges, 2020-21 to 2021-22

Year	IEX			PXIL		
	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Partici-pation	OAC Purchase Volume (MU)	Total Volume (MU)	% OAC Purchase Partici-pation
2020-21	776.73	9467.94	8.2%	0.00	2.29	0.0%
2021-22	1658.36	19908.07	8.3%	0.00	0.00	-

Note: RTM is operational on the Power Exchanges from 1st June 2020

As may be observed from the tables above, in 2021-22 the volume procured by OA consumers in DAM has declined, which could be due to gradual shift of the OA consumers towards the G-DAM segment.

8. Major Sellers and Buyers of Electricity in the Short-term market

Details of top 10 sellers and buyers of electricity through traders (bilateral trader segment transactions) in 2021-22 are given in Table-23 and Table-24 respectively. The volume of electricity transacted by these major sellers and buyers, their share in total volume and the price at which they have sold or purchased are also provided in the tables.

Details of top 10 sellers in DAM, G-DAM and RTM segments of IEX in 2021-22 are given in Table-25(a), 25(b) and 25(c) respectively and details of top 10 buyers of electricity in DAM, G-DAM and RTM segments of IEX are given in Table-26(a), 26(b) and 26(c) respectively. Table-27 and Table-28 provides details of Top 10 sellers and buyers of electricity in DAM of PXIL. There was no trade of electricity in G-DAM and RTM of PXIL during the period.

Table 23: Major Sellers of Electricity through Traders, 2021-22

S.No.	Seller	State	Volume (MU)	Approx. % of total volume transacted through Traders	Weighted Average Price (₹/kWh)
1	Raipur Energen Ltd.	Chhattisgarh	6151.95	25.48%	3.49
2	Jaypee Nigrie STPP	Madhya Pradesh	2478.68	10.27%	3.39
3	JITPL	Odisha	2187.63	9.06%	2.93
4	Raigarh Energy Generation Ltd.	Chhattisgarh	1828.32	7.57%	3.79
5	HPSEB (including GOHP)	Himachal Pradesh	1558.45	6.45%	3.94
6	DB Power Ltd	Chhattisgarh	1396.50	5.78%	3.63
7	Jindal Power Ltd.	Chhattisgarh	1260.00	5.22%	4.53
8	Sembcorp Energy India Limited	Andhra Pradesh	986.70	4.09%	4.35
9	Adani Power Ltd.	Gujarat	744.37	3.08%	6.25
10	Essar Power MP Limited	Madhya Pradesh	718.06	2.97%	2.97

Note: Volume sold by major sellers and total volume transacted through traders does not include the volume through banking arrangements.

Table 24: Major Buyers of Electricity through Traders, 2021-22

S.No.	Buyer	State	Volume (MU)	Approx. % of total volume transacted through traders	Weighted Average Price (₹/kWh)
1	GUVNL	Gujarat	3811.97	15.79%	3.09
2	PSPCL	Punjab	3622.77	15.00%	3.47
3	Adani Electricity Mumbai Ltd	Maharashtra	2106.89	8.73%	5.69
4	HPPC	Haryana	1969.06	8.16%	3.18
5	TANGEDCO	Tamil Nadu	1618.18	6.70%	3.76
6	HPSEB	Himachal Pradesh	1532.39	6.35%	2.85
7	BSES Rajdhani Power Limited	Delhi	1289.76	5.34%	3.06
8	Indian Railways	Pan India	1224.03	5.07%	3.60
9	APPCC	Andhra Pradesh	892.54	3.70%	4.19
10	JVVNL	Rajasthan	781.14	3.24%	3.78

Note: Volume bought by major buyers and total volume transacted through traders does not include the volume through banking arrangements.

As can be observed from Table-24, the weighted average purchase prices of electricity of major buyers such as Adani Electricity Mumbai Ltd, APPCC, JVVNL and TANGEDCO from traders (bilateral transactions) were much higher than the weighted average price for the entire bilateral trader segment (₹ 3.69/kWh).

Table-25(a): Major Sellers of Electricity in Day Ahead Market of IEX, 2021-22

S.No.	Name of Seller	State/ Regional Entity	Sell Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Sell Price (₹/kWh)
1	UPPCL	Uttar Pradesh	6063.71	9.31%	3.93
2	WBSEDCL	West Bengal	5702.94	8.75%	3.86
3	Teesta Urja Ltd	Sikkim	2971.71	4.56%	5.05
4	BSPHCL	Bihar	2961.36	4.55%	3.47
5	CSPDCL	Chhattisgarh	2605.38	4.00%	3.26
6	Sembcorp Energy India Ltd	Andhra Pradesh	2480.46	3.81%	5.83
7	GRIDCO	Orissa	2436.51	3.74%	4.13
8	RUNVL	Rajasthan	2337.33	3.59%	3.33

9	PCKL	Karnataka	2074.28	3.18%	3.93
10	Jindal Power Ltd Stage I	Chhattisgarh	2013.42	3.09%	5.42
Note: Total Volume transacted through Day Ahead Market in IEX was about 65143.03 MU.					

Table-25(b): Major Sellers of Electricity in the Green Day Ahead Market of IEX, 2021-22

S.No.	Name of Seller	State/ Regional Entity	Sell Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Sell Price (₹/kWh)
1	PCKL	Karnataka	146.22	15.89%	3.81
2	TSSPDCL	Telangana	105.29	11.44%	3.70
3	Adani Hybrid Energy Jaisalmer One Ltd. Solar	Rajasthan	36.90	4.01%	4.16
4	Adani Hybrid Energy Jaisalmer Three Limited Solar	Rajasthan	36.42	3.96%	4.58
5	Narmada Sugar Pvt Ltd	Madhya Pradesh	34.94	3.80%	4.99
6	KPR Sugar Mill Ltd	Karnataka	32.95	3.58%	5.82
7	ReNew Solar Energy (Jharkhand Three) Pvt Ltd	Rajasthan	30.36	3.30%	5.82
8	Shri Prabhulingeshwar Sugars & Chemicals Ltd.	Karnataka	27.35	2.97%	5.25
9	Core Green Sugar & Fuels Pvt Ltd.	Karnataka	23.90	2.60%	5.84
10	Vijayanagar Sugar Pvt Ltd.	Karnataka	23.05	2.50%	5.35
Note: Total Volume transacted through Green Day Ahead Market in IEX was about 920.45 MU.					

Table-25(c): Major Sellers of Electricity in Real Time Market of IEX, 2021-22

S.No.	Name of Seller	State/ Regional Entity	Sell Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Sell Price (₹/kWh)
1	MPPMCL	Madhya Pradesh	1622.27	8.15%	4.27
2	WBSEDCL	West Bengal	1538.32	7.73%	4.83

3	UPPCL	Uttar Pradesh	1166.59	5.86%	3.54
4	JKPCL	J&K	1157.93	5.82%	3.61
5	RUVNL	Rajasthan	1153.72	5.80%	3.91
6	TSSPDCL	Telangana	1097.75	5.51%	5.42
7	GRIDCO	Orissa	980.67	4.93%	4.16
8	Power Company of Karnataka Ltd.	Karnataka	829.52	4.17%	4.26
9	BSPHCL	Bihar	796.88	4.00%	4.45
10	Kameng HEP	Arunachal Pradesh	698.44	3.51%	4.10
Note: Total Volume transacted through Real Time Market in IEX was about 19908.04 MU.					

Table-26(a): Major Buyers of Electricity in Day Ahead Market of IEX, 2021-22

S.No.	Name of Buyer	State/ Regional Entity	Buy Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Buy Price (₹/kWh)
1	GUVNL	Gujarat	13414.68	20.59%	5.16
2	APSPDCL	Andhra Pradesh	7897.43	12.12%	5.34
3	PSPCL	Punjab	5340.87	8.20%	4.33
4	TSSPDCL	Telangana	3437.62	5.28%	4.89
5	TANGEDCO	Tamil Nadu	3317.71	5.09%	7.30
6	MSEDCL	Maharashtra	2644.66	4.06%	4.66
7	HPPC	Haryana	2609.04	4.01%	5.52
8	Adani Electricity Mumbai Limited	Maharashtra	2560.85	3.93%	3.32
9	RUVNL	Rajasthan	2220.16	3.41%	4.83
10	JKPCL	J&K	1977.30	3.04%	3.76
Note: Total Volume transacted through Day Ahead Market in IEX was about 65143.03 MU.					

Table-26(b): Major Buyers of Electricity in the Green Day Ahead Market of IEX, 2021-22

S.No.	Name of Buyer	State/ Regional Entity	Buy Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Buy Price (₹/kWh)
1	DNHDDPDCL	Dadra & Nagar Haveli and Daman & Diu	234.59	25.49%	4.10

2	APDCL	Assam	137.50	14.94%	6.51
3	BSES Rajdhani Power Limited	Delhi	75.63	8.22%	3.76
4	CESC	West Bengal	72.74	7.90%	5.30
5	SAIL RSP Rourkela	Orissa	50.28	5.46%	3.78
6	MSEDCL	Maharashtra	38.94	4.23%	6.58
7	Vedanta Limited SEZ Unit Jharsuguda	Orissa	34.22	3.72%	4.76
8	HPPC	Haryana	25.72	2.79%	3.53
9	PSPCL	Punjab	24.68	2.68%	5.38
10	BSES Yamuna Power Limited	Delhi	21.80	2.37%	7.70
Note: Total Volume transacted through Green Day Ahead Market in IEX was about 920.45 MU.					

Table-26(c): Major Buyer of Electricity in Real Time Market of IEX, 2021-22

S.No.	Name of Buyer	State/ Regional Entity	Buy Volume (MU)	Percentage of the Total Volume Transacted in IEX	Weighted Average Buy Price (₹/kWh)
1	JKPCL	J&K	2426.68	12.19%	3.87
2	APSPDCL	Andhra Pradesh	1929.42	9.69%	5.46
3	RUVNL	Rajasthan	1786.57	8.97%	4.46
4	TSSPDCL	Telangana	1777.73	8.93%	3.49
5	GUVNL	Gujarat	1210.35	6.08%	5.40
6	HPPC	Haryana	1099.65	5.52%	5.56
7	TANGEDCO	Tamil Nadu	1083.20	5.44%	6.85
8	MSEDCL	Maharashtra	943.44	4.74%	3.96
9	BSPHCL	Bihar	607.30	3.05%	4.63
10	PSPCL	Punjab	596.52	3.00%	3.03
Note: Total Volume transacted through Real Time Market in IEX was about 19908.04 MU.					

From Table-26(a), it can be seen that the weighted average prices of electricity for major buyers such as TANGEDCO, HPPC, APSPDCL and GUVNL in the Day Ahead Market of IEX were much higher than the weighted average price of the electricity transacted through the entire day ahead market of IEX (₹ 4.79/kWh). In case of G-DAM segment (Table 26 (b)), weighted average prices of electricity for major buyers like BSES Yamuna Power Limited, MSEDCL, APDCL, PSPCL and CESC were much higher than the weighted average price of the electricity transacted through the entire G-DAM of IEX (₹ 4.83/kWh). Similarly, in RTM in IEX, the weighted average prices of electricity for major buyers such as TANGEDCO, HPPC, APSPDCL and GUVNL were much higher than the weighted average price of the electricity transacted through the entire real time market of IEX (₹ 4.54 kWh) as may be seen in Table 26(c).

Table-27: Major Sellers of Electricity in Day Ahead Market of PXIL, 2021-22

S. No	Name of the Seller	State/ Regional Entity	Sell Volume (MU)	Percentage of total volume transacted in PXIL	Weighted Average Sell Price (₹/kWh)
1	KSEB	Kerala	22.17	52.04%	3.95
2	BSPHCL	Bihar	5.03	11.80%	2.51
3	UPPCL	Uttar Pradesh	4.76	11.16%	3.50
4	GRIDCO	Odisha	4.22	9.91%	3.70
5	JBVNL	Jharkhand	3.16	7.42%	2.36
6	MPPMCL	Madhya Pradesh	2.23	5.23%	4.69
7	HPSEB	Himachal Pradesh	0.53	1.23%	3.83
8	PSPCL	Punjab	0.30	0.69%	6.07
9	GMR Kamalanga Energy Limited	Odisha	0.12	0.28%	2.35
10	GMR Warora Energy Ltd	Maharashtra	0.08	0.18%	2.80

Note: Total Volume transacted through the Day Ahead Market of PXIL was about 42.61 MU.

Table-28: Major Buyer of Electricity in Day Ahead Market of PXIL, 2021-22

S.No.	Name of Buyer	State/ Regional Entity	Buy Volume (MU)	Percentage of the Total Volume Transacted in PXIL	Weighted Average Buy Price (₹/kWh)
1	GUVNL	Gujarat	21.30	49.99%	3.54
2	APSPDCL	Andhra Pradesh	10.58	24.83%	3.59
3	TANGEDCO	Tamil Nadu	3.06	7.17%	4.35
4	JBVNL	Jharkhand	3.05	7.15%	4.12
5	PSPCL	Punjab	1.48	3.48%	1.72
6	BSPHCL	Bihar	1.15	2.69%	5.10
7	HPSEB	Himachal Pradesh	0.94	2.21%	3.32
8	Adani Electricity Mumbai Ltd	Maharashtra	0.90	2.11%	3.41
9	RUVNL	Rajasthan	0.13	0.30%	4.01

10	Vedanta Ltd SEZ Unit Jharsuguda	Odisha	0.03	0.06%	4.99
Note: Total Volume transacted in the Day Ahead Market of PXIL was about 42.61 MU.					

From Table-28, it can be seen that the weighted average prices of electricity for major buyers such as BSPHCL, Vedanta Ltd SEZ Unit Jharsuguda, TANGEDCO and JBVNL in DAM of PXIL were much higher than the weighted average price of the electricity transacted through the entire day ahead market of PXIL (₹ 3.68/kWh).

As can be observed from the above analysis of top buyers and sellers, the dominant sellers, both at the power exchanges and traders, are a mixed group comprising of independent power producers, distribution companies and state government agencies. The major buyers from traders and at the power exchanges are mostly state distribution companies and industrial consumers.

9. Effect of Congestion on the Volume of Electricity Transacted through Power Exchanges

The volume of electricity transacted through power exchanges is sometimes constrained due to transmission congestion. The details of congestion in both the power exchanges are shown in Table-29 and Table-30.

The effect of congestion on volume of electricity transacted through power exchanges during 2009-10 to 2021-22 is shown in Table-29. It can be observed from the table that there is an increasing trend in the unconstrained cleared volume and actual volume transacted. Unconstrained cleared volume and actual volume transacted increased from 8.10 BU and 7.09 BU respectively in 2009-10 to 86.09 BU and 86.01 BU respectively in 2021-22. The volume of electricity that could not be cleared, i.e., the difference of unconstrained cleared volume and actual volume transacted, as % to unconstrained cleared volume was higher during the period from 2011-12 to 2016-17, after which it has come down significantly. Congestion for the volume of electricity transacted through power exchanges reduced to a great extent since grid integration (integration of NEW Grid and SR Grid) in December 2013, which resulted in a declining trend in the volume of electricity that could not be cleared as percentage to unconstrained cleared volume in both the power exchanges from 2013-14 onwards. From 2017-18 onwards, the volume of electricity that could not be cleared as % to unconstrained cleared volume was consistently less than 1%, which shows that the congestion remained insignificant.

Table-29: Effect of Congestion on the Volume of Electricity Transacted through Power Exchanges, 2009-10 to 2021-22

Year	Unconstrained Cleared Volume (BU)	Actual Cleared Volume and hence scheduled* (BU)	Volume of electricity that could not be cleared due to congestion (BU)	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume
2009-10	8.10	7.09	1.01	12%
2010-11	14.26	13.54	0.72	5%
2011-12	17.08	14.83	2.26	13%
2012-13	27.67	23.02	4.65	17%
2013-14	35.62	30.03	5.59	16%
2014-15	31.61	28.46	3.14	10%
2015-16	36.36	34.20	2.16	6%
2016-17	41.60	40.08	1.52	4%
2017-18	45.86	45.65	0.21	0.5%
2018-19	50.69	50.22	0.47	0.9%
2019-20	49.36	49.16	0.20	0.4%
2020-21	70.13	70.09	0.04	0.06%
2021-22	86.09	86.01	0.06	0.09%

** This is the power finally scheduled after factoring in congestion and/or other reasons of not scheduling like real time curtailment etc.*

Source: IEX, PXIL & NLDC

During 2021-22, in IEX, the unconstrained cleared volume and the actual volume transacted was 65.18 BU and 65.14 respectively in DAM segment (Table-30), whereas in RTM in IEX, the unconstrained cleared volume and the actual volume transacted was 19.95 BU and 19.91 BU respectively. Therefore, the actual transacted volume was 0.05% lesser than unconstrained volume in DAM and 0.23% lesser than unconstrained cleared volume in RTM segment of IEX. In case of G-DAM in IEX, there was no congestion reported during the period.

During the same period, in PXIL the unconstrained cleared volume and the actual volume transacted was 0.043 BU and 0.043 BU respectively in DAM segment (Table-30). Therefore, there was no congestion in DAM in PXIL. There were no transactions under G-DAM and RTM in PXIL during the period.

Table-30: Details of Congestion in Power Exchanges, 2021-22

	Items	IEX			PXIL			Total
		DAM	G-DAM	RTM	DAM	G-DAM	RTM	
A	Unconstrained Cleared Volume (BU)	65.18	0.92	19.95	0.043	0.00	0.000	86.09
B	Actual Cleared Volume and hence scheduled* (BU)	65.14	0.92	19.91	0.043	0.00	0.000	86.01
C	Volume of electricity that could not be cleared and hence not scheduled because of congestion (BU)	0.01	0.00	0.05	0.00	0.00	0.00	0.06
D	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume	0.05%	0.00%	0.23%	0.00%	0.00%	0.00%	0.09%

** This is the power finally scheduled after factoring in congestion and/or other reasons of not scheduling like real time curtailment etc.*

Source: IEX, PXIL & NLDC

Transmission congestion, consequent market splitting and the resultant difference in market prices in different regions give rise to congestion charges. The annual congestion charges of both power exchanges for the period from 2008-09 to 2021-22 are provided in Table-31.

Table-31: Congestion Charges of Power Exchanges, 2008-09 to 2021-22

Year	Congestion Charges of IEX (₹ Crore)	Congestion Charges of PXIL (₹ Crore)	Total (₹ Crore)
2008-09	5.27	0.00	5.27
2009-10	255.40	22.39	277.79
2010-11	273.14	86.61	359.75
2011-12	419.13	65.62	484.76
2012-13	417.37	35.93	453.30
2013-14	387.23	5.10	392.33
2014-15	502.41	1.64	504.05
2015-16	214.08	0.14	214.22
2016-17	305.99	0.09	306.08
2017-18	56.56	0.003	56.56

2018-19	137.52	0.00	137.52
2019-20	55.65	0.00	55.65
2020-21	70.95	0.006	70.96
2021-22	23.35	0.00	23.35

Source: NLDC

10. Ancillary Services Operations

10.1 Background

Ancillary Services is one of the four essential pillars of Electricity Market design, viz., Scheduling and Despatch, Imbalance Settlement, Congestion Management and Ancillary Services. Ancillary Services are support services to maintain power system reliability and support its primary function of delivering energy to customers. These are deployed by the system operator over various timeframes to maintain the required instantaneous and continuous balance between aggregate generation and load. Ancillary Services consist of services required for (a) maintaining load-generation balance (frequency control); (b) maintaining voltage and reactive power support; and (c) maintaining generation and transmission reserves. Historically, ancillary services were provided by the vertically integrated utilities along with the energy supply services. With the unbundling of vertically integrated utilities and increasing private sector participation and competition introduced in the energy markets, there is an increasing need for administering such services so as to ensure reliable and secure grid operation. Ancillary Services are broadly classified as follows:

(i) **Frequency Control Ancillary Services (FCAS)**: Three levels of Frequency Control are generally used to maintain the balance between generation and load, i.e., Primary Frequency Control, Secondary Frequency Control, Tertiary Frequency Control. These three levels differ as per their time of response to a fluctuation and the methodology adopted to realize the fundamental operating philosophy of maintaining reliability and economy.

(ii) **Network Control Ancillary Services (NCAS)**: This can be further subdivided into Voltage Control Ancillary Service and Power Flow Control Ancillary Services.

(iii) **System Restart Ancillary Services (SRAS)**: It is used to restore the system after a full or partial blackout. Black start is vital and inexpensive service. Its costs are primarily the capital cost of the equipment used to start the unit, the cost of the operators, the routine maintenance and testing of equipment and the cost of fuel when the service is required. At present this is a mandatory service.

10.2 Regulatory Framework of Ancillary Services

Ancillary Services are defined, under Regulation (2)(1)(b) of the CERC (Indian Electricity Grid Code), Regulations, 2010 (IEGC), as follows: *"…in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, e.g. active power support for load following, reactive power support, black start, etc;…*"

The Commission notified the CERC (Ancillary Services Operations) Regulations on 13th August, 2015. The objective of Reserves Regulation Ancillary Services (RRAS) is to restore the frequency level at desired level and to relieve the congestion in the transmission network. Specifically, these regulations are the first step towards introducing Ancillary Services in the country that will enable the grid operator to ensure reliability and stability in the grid. The RRAS shall support both "Regulation Up" service (that provides capacity by responding to signals or instruction of the Nodal Agency to increase generation) and "Regulation Down" service (that provides capacity by responding to signals or instruction of the Nodal Agency to decrease generation). The detailed procedures were laid out on the 08th March 2016 and Ancillary Services were implemented by the Nodal Agency, i.e., NLDC in coordination with RLDCs from 12th April, 2016.

Regulation Up Service shall utilize "un-requisitioned surplus" of inter-State generating stations, whose tariff is determined or adopted by the Commission for their full capacity. Un-requisitioned surplus means the reserve capacity in a generating station that has not been requisitioned and is available for dispatch, and is computed as the difference between the declared capacity of the generating station and its total schedule under long-terms, medium-term and short-term transactions, as per the relevant regulations of the Commission. On the other hand, Regulation Down service may be provided by any eligible generator. Incentives for both the generators and their beneficiaries have been built into the framework.

As per the regulation, all the generators, that are regional entities, and whose tariff for the full capacity is determined or adopted by the CERC have been mandated to provide Ancillary Services as RRAS Providers. NLDC, through the RLDCs, has been designated as the Nodal Agency for Ancillary Services Operations. The Nodal Agency prepares the Merit Order Stack based on the variable cost of generation. Separate stacks are prepared for Up and Down.

Ancillary Services may be triggered because of extreme weather forecast, generating unit or transmission line outages, trend of load met, trend of frequency, any abnormal event such as outage of hydro generating units due to silt, coal supply blockade, etc., excessive loop flows leading to congestion, trend of computed Area Control Error (ACE) at regional level, recall by the original beneficiary, grid voltage profile at important nodes, 'N-1' criteria not being satisfied in a transmission corridor, loading of transmission lines beyond limits specified in CEA Manual on Transmission Planning Criteria.

A virtual regional entity called "Virtual Ancillary Entity (VAE)" has been created in the respective Regional Pool for scheduling and accounting. The quantum of RRAS instruction is incorporated in the schedule of RRAS providers. RRAS instruction may be scheduled to the VAE in any one or more regional grids. The deviation in schedule of the RRAS providers, beyond the revised schedule, is being settled as per the CERC Deviation Settlement Mechanism (DSM) Regulations. The energy dispatched under RRAS is deemed delivered ex-bus.

Nodal agency directs the RRAS provider to withdraw RRAS, on being satisfied, that the circumstances leading to triggering of RRAS services have ceased to exist. The RRAS energy accounting is being done by the respective Regional Power Committee (RPC) on weekly basis along with DSM account, based on interface meters data and schedule. A separate RRAS statement is being issued by RPC along with Regional

DSM account. Any post-facto revision in rates/charges by RRAS providers is not permitted. In case of Regulation Up, fixed charges and variable charges along with pre-specified mark-up are payable to the RRAS providers from the pool. CERC, vide order dated 29th February 2016, specified the mark-up for participation in Regulation 'Up' as 50 paisa/kWh. In case of Regulation Down, 75 percent of the variable charges are payable by RRAS providers to the pool. No commitment charges are payable to the RRAS provider.

The existing framework of Ancillary Services predominantly utilises the thermal power stations which have ramping limitations and as such there is a need for a fast response ancillary service. The fast response reserves become all the more essential in view of the increasing penetration of intermittent renewable energy sources. The present administered mechanism of RRAS cannot accommodate such resources, especially the new and emerging technologies/ resources like energy storage and demand side response. Given the changes in technology, generation mix and increasing decentralized generation, and location specific requirements for ancillary services, the Commission felt the need for a comprehensive framework of Ancillary Services and notified the CERC (Ancillary Services) Regulations, 2022 on 31st January 2022. These regulations shall come into effect from the date as notified by the Commission.

These regulations aim to provide mechanisms for procurement, through administered as well as market-based mechanisms, deployment and payment of Ancillary Services at the regional and national level for maintaining the grid frequency close to 50 Hz, and restoring the grid frequency within the allowable band as specified in the Grid Code and for relieving congestion in the transmission network, to ensure smooth operation of the power system, and safety and security of the grid.

The Commission has recognised the following types of Ancillary Services:

(a) Primary Reserve Ancillary Service (PRAS);

(b) Secondary Reserve Ancillary Service (SRAS);

(c) Tertiary Reserve Ancillary Service (TRAS); and

(d) Such other Ancillary Services as specified in the Grid Code

The Ancillary Services Regulations, 2022 cover SRAS and TRAS and stipulate that PRAS and other Ancillary Services shall be governed by the Grid Code or as specified separately by the Commission.

The SRAS is proposed to be procured through an administered mechanism to start with. However, there is an enabling provision for market-based procurement of SRAS, the framework for which can be specified separately. The regulations seek to reward fast ramping resources in the SRAS segment.

The TRAS is proposed to be procured through market-based mechanism. A separate Ancillary Service product is to be introduced in the existing Day Ahead Market and Real Time Market. For TRAS-Up, the principle of uniform market clearing price (MCP) shall be adopted. However, for TRAS-Down, the pay-as-you-bid mechanism has been adopted. TRAS-Up cleared but not despatched would be given commitment charge at 10 percent of the MCP for TRAS-Up subject to the ceiling of 20 paise/kWh.

10.3 RRAS Instructions issued by Nodal Agency

Table-32 provides month-wise details on maximum power despatched and maximum power regulated in a time block based on the instructions issued. It can be observed from the table that during the year 2021-22 in a time block, maximum power despatched was 3700 MW in December 2021 while the maximum power regulated was 4500 MW in April and May 2021.

Table-32: Maximum Ancillary despatched in a Time Block (MW), 2021-22

Month	Max Regulation "UP"	Max Regulation "DOWN"
Apr-21	1500	4500
May-21	1564	4500
Jun-21	2000	4000
Jul-21	1750	3500
Aug-21	2000	3500
Sep-21	2000	3500
Oct-21	2500	4000
Nov-21	2500	4000
Dec-21	3700	3940
Jan-22	1642	4000

Feb-22	2923	3500
Mar-22	1672	4000

Source: POSOCO Website

10.4 RRAS Accounting and Settlement

As per Regulation 12 of the CERC (Ancillary Services Operations) Regulations 2015, the Regional Power Committees (RPCs) are required to issue the weekly accounts for RRAS along with the weekly DSM accounts. The RRAS accounts include fixed charges, variable charges, markup, amount of fixed charges to be refunded to the beneficiaries and the payments made from/to the DSM pool.

Energy scheduled to/from Virtual Ancillary Entity (VAE) under RRAS and the payments made for ancillary services during 2016-17 to 2021-22 are given in Table-33.

Table-33: Energy Scheduled and Payments made for Ancillary Services, 2016-17 to 2021-22

Year	Energy scheduled to/from Virtual Ancillary Entity under RRAS (MU)		Payments made for Ancillary Services (₹ Crore)	
	Regulation UP	Regulation DOWN	To RRAS provider(s) from DSM pool for Regulation UP	By RRAS provider(s) to DSM pool for Regulation DOWN
2016-17	2212.28	286.00	939.78	42.39
2017-18	4149.25	243.72	2011.47	43.60
2018-19	4811.69	685.42	2810.73	140.83
2019-20	2435.01	1941.31	1333.36	398.40
2020-21	1649.50	2940.01	713.15	610.69
2021-22	2778.22	5353.44	1952.23	1230.65

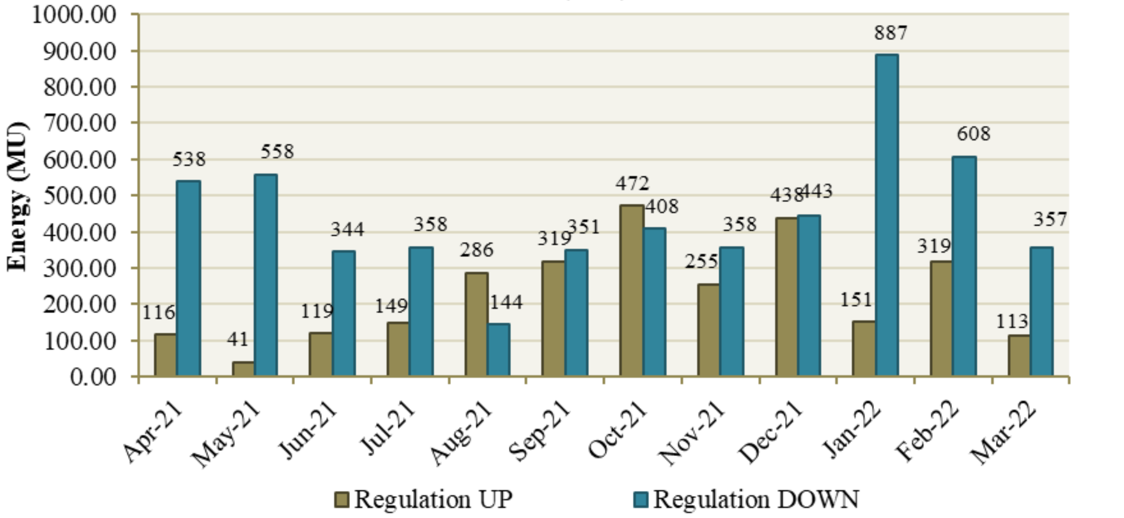
Source: POSOCO Website

The energy scheduled under Regulation UP of RRAS has increased from 2212.28 MU in 2016-17 to 2778.22 MU in 2021-22, whereas the energy scheduled under Regulation DOWN of RRAS was increased from 286.00 MU in 2016-17 to 5353.44 MU in 2021-22.

Month-wise energy scheduled to/from VAE under RRAS during 2021-22 can be seen in Figure-36. It can be observed from the figure that ancillary despatch under

Regulation UP was relatively low when compared with the ancillary despatch under Regulation DOWN during most of the period in 2021-22, except in August and October 2021.

Figure-36: Energy scheduled to/from Virtual Ancillary Entity under RRAS (MU), 2021-22



***

Chapter-III

Cross Border Trade of Electricity

1. Background

The Cross Border Trade of Electricity (import or export of electricity between India and its neighbouring countries) between India and Nepal and between India and Bhutan has been taking place for more than fifty years. The Cross Border trade with Bangladesh and Myanmar was respectively started in the year 2013 and year 2017.

The Cross Border Trade of electricity has mainly been taking place under bilateral Memorandum of Understanding/ Power Trade Agreement. The South Asian Association for Regional Cooperation (SAARC) countries envisaged the need for cross border electricity cooperation and signed the SAARC Framework Agreement for Energy Cooperation on 27.11.2014, recognizing the importance of electricity in promoting economic growth and improving the quality of life in the region. In order to facilitate and promote cross border trade of electricity with greater transparency, consistency and predictability in regulatory approaches across jurisdictions and minimize perception of regulatory risks, the Guidelines on Cross Border Trade of Electricity had been prepared by the Inter-Ministerial Working Group in consultation with various stakeholders.

The Ministry of Power (MOP) issued the Guidelines on Cross Border Trade of Electricity on 5.12.2016, which was subsequently substituted by the 'Guidelines for Import/Export (Cross Border) of Electricity-2018' issued on 18.12.2018, to promote cross border trade of electricity with neighbouring countries. Following the guidelines, the Central Electricity Regulatory Commission issued the CERC (Cross Border Trade of Electricity) Regulations, 2019 on 8.03.2019. The Central Electricity Authority (CEA) issued 'Draft Conduct of Business Rules of the Designated Authority' on 25.04.2019 for facilitating the Cross Border Trade of Electricity. In continuation to the draft business rules, on 21.02.2021, CEA notified the 'Procedure for Approval and Facilitating Import/Export (Cross Border) of Electricity by the Designated Authority'.

Under the CERC (Cross Border Trade of Electricity) Regulations 2019, the sale and purchase of electricity between India and the neighbouring countries is allowed through mutual agreements between the local entities and the entities of the neighboring countries, through bilateral agreements between two countries, bidding route or through mutual agreements between entities. Any Indian trader, after obtaining approval from Designated Authority, can trade in Indian Power Exchanges on behalf of any Entity of neighbouring country complying with these regulations.

2. Cross Border Trade of Electricity between India and its Neighbouring Countries

Presently, India is a net exporter of electricity to Nepal, Bangladesh, and Myanmar, while India is a net importer of electricity from Bhutan. Table-34 below provides the details on Cross Border Trade of Electricity between India and its neighbouring countries during the period from 2013-14 to 2021-22. From the table, it can be observed that India was net importer of electricity during the period from 2013-14 to 2015-16 and then has become net exporter of electricity.

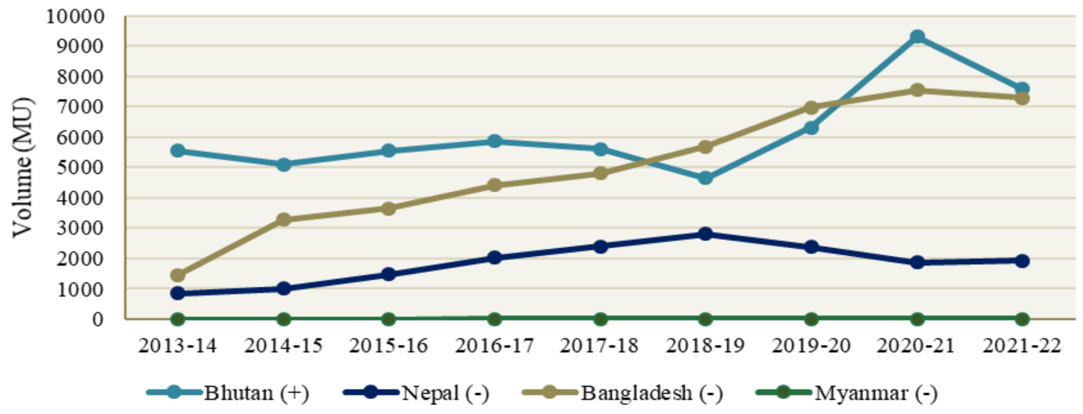
Table-34: Cross Border Trade of Electricity between India and its Neighbouring Countries, 2013-14 to 2021-22 (MU)

Year	Bhutan (+)	Nepal (-)	Bangladesh (-)	Myanmar (-)	Net Export/Import by India
2013-14	5555.18	840.37	1448.19	0.00	3266.62
2014-15	5109.48	997.17	3271.89	0.00	840.42
2015-16	5555.07	1469.59	3654.40	0.00	431.08
2016-17	5863.58	2021.21	4419.61	3.23	-580.47
2017-18	5611.14	2388.96	4808.83	5.07	-1591.72
2018-19	4657.07	2798.84	5690.31	6.67	-3838.75
2019-20	6310.73	2373.06	6987.94	8.61	-3058.88
2020-21	9318.17	1865.05	7551.99	9.24	-108.11
2021-22	7596.71	1921.09	7301.74	8.80	-1634.92

(+) Import; (-) Export

Source: POSOCO

Figure-37: Volume of Electricity traded between India and Neighbouring Countries (MU), 2013-14 to 2021-22



3. Cross Border Electricity Trade through Power Exchange

During 2021-22, the Cross Border Electricity Trade was also commenced in Day Ahead Market of IEX. The trade with Nepal was commenced on 17.04.2021, whereas the trade with Bhutan was commenced on 01.01.2022. The table below presents the details of such trade with Nepal and Bhutan.

Table-35: Month-wise Cross Border Trade of Electricity at IEX, 2021-22

Month	Nepal				Bhutan			
	Buy		Sell		Buy		Sell	
	Volume Traded (MU)	Weighted Average Price (`/kWh)	Volume Traded (MU)	Weighted Average Price (`/kWh)	Volume Traded (MU)	Weighted Average Price (`/kWh)	Volume Traded (MU)	Weighted Average Price (`/kWh)
Apr-21	16.47	3.24	-	-	-	-	-	-
May-21	118.74	2.81	-	-	-	-	-	-
Jun-21	42.89	2.77	-	-	-	-	-	-
Jul-21	72.23	2.91	-	-	-	-	-	-
Aug-21	3.49	3.02	-	-	-	-	-	-
Sep-21	-	-	-	-	-	-	-	-
Oct-21	0.01	5.65	-	-	-	-	-	-
Nov-21	-	-	26.21	3.08	-	-	-	-
Dec-21	69.03	3.27	5.83	3.73	-	-	-	-
Jan-22	158.3	2.45	-	-	101.28	2.48	-	-
Feb-22	157.32	3.28	-	-	104.7	3.07	-	-
Mar-22	147.36	6.01	-	-	34.13	3.51	-	-

Source: IEX

***

Chapter-IV

Tariff of Long-term Sources of Power

1. Background

Section 61 & 62 of the Electricity Act, 2003 provide for tariff regulation and determination of tariff of generation, transmission, wheeling and retail sale of electricity by the Appropriate Commission. The CERC has the responsibility to regulate the tariff of generating companies owned or controlled by the Central Government. The CERC specifies the terms and conditions for the determination of tariff for the generating companies guided by the principles and methodologies specified. The principles of the tariff are based on: (a) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments; (b) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner; (c) rewarding efficiency in performance; (d) the tariff progressively reflects the cost of supply of electricity and also reduces and eliminates cross-subsidies; and (e) the promotion of co-generation and generation of electricity from renewable sources of energy.

Section 63 of the Act states that “Notwithstanding anything contained in section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government”. Competitive procurement of power requirement by the Distribution Licensees reduces the overall cost of power procurement and in turn leads to significant benefits to consumers.

2. Guidelines and Standard Bidding Documents (SBDs) for Procurement of Electricity by Distribution Licensees through Tariff based bidding process

In compliance with section 63 of the Electricity Act 2003, the Central Government has notified Guidelines for Procurement of Power by Distribution Licensees through Competitive Bidding.

i) **Long Term procurement of Power**: Central Government had initially issued the Standard Bidding Documents (SBDs) containing Request for Qualification (RfQ), Request for Proposal (RfP) and Power Purchase Agreement (PPA) for long term procurement of power from Case 2 projects (having specified site and location) through tariff based competitive bidding in 2006 and amended it from time to time. The Standard Bidding Documents for long term procurement of power from Case-1 projects (where the location, technology or fuel is not specified) were issued in the year 2009 and amended it in 2010. In pursuance of the decision of the EGoM on Ultra Mega Power Projects (UMPPs) having specified site and location, the SBDs for Case-2 have been further reviewed and the Model Bidding Documents (MBDs) comprising the Model RFQ, Model RFP and the Model PPA for construction and operation of power generation projects/ UMPPs on design, Build, Finance, Operate and Transfer (DBFOT) basis have been issued on 20 Sept, 2013. The Guidelines for procurement of electricity from Thermal Power Stations set up on DBFOT basis for Case-2/UMPPs have been published in the Gazette of India on 21st September, 2013. Model Bidding Documents (MBDs) for Thermal Power Stations set up on Design, Build, Finance, Own and Operate (DBFOO) basis for Case-1 issued on 8.11.2013. Further, amendments have been issued in the Documents on 5.5.2015. In order to facilitate use of linkage coal in the long term procurement of power by Distribution Licensees as per the provisions of SHAKTI Policy, SBDs and Guidelines for long term Procurement of Electricity from Thermal Power Stations set up on DBFOO basis have been revised and issued in March, 2019.

ii) **Medium Term Procurement of Power**: Model Bidding Documents (MBDs) for procurement of electricity for medium term from power generating stations set up and/or operated on Finance, Own and Operate (FOO) basis was issued on 29.1.2014. Further, amendments have been issued in the Documents of 20.8.2015. Model Bidding Documents (MBDs) for procurement of peaking power for medium term issued on 20.2.2014. In order to introduce e-bidding process along with reverse action, revised Guidelines and Model Bidding Documents for medium-term procurement of power by Distribution Licensees through tariff based competitive bidding process was notified on 17 January, 2017. Introduction of e-bidding process along with reverse auction will result in greater transparency and fairness in the procurement process for ultimate benefit of the consumers. Further, for enabling the use of linkage coal as per the new coal linkage policy (SHAKTI Policy) of Ministry of Coal, Revised MBDs and revised Guidelines for Procurement of Electricity for Medium Term were issued on 29.01.2019 and 30.01.2019 respectively.

iii) **Short Term procurement of Power**: The Central Government has issued Guidelines for short-term procurement of electricity i.e. for a period of less than or equal to one year under section 63 of the Electricity Act, 2003 on 16 May, 2012. For introduction of e-reverse auction, the revised guidelines for short-term procurement of electricity were also issued on 30 March, 2016.

The power procurement through competitive bidding resulted in significant capacity addition by private sector. The details on tariff determined by CERC for inter-state power generating companies, mainly the tariff of central public sector power generating companies are discussed in the followings sections.

3. Tariff of Central Public Sector power generating companies

In 2021-22, the central public sector power generating companies (NTPC, NHPC, NLC, NEEPCO, etc.)/central government owned generating companies accounted for about 35% of the total power generation in the country which was mainly procured by the various distribution companies through long-term Power Purchase Agreements.

The price paid by distribution companies to procure power from central government owned generating companies in 2021-22 is shown in Table-36 and 37. It can be seen that, on an average, the distribution companies paid between ₹2.04 and ₹7.85 per kWh for procuring power from central thermal power stations (Table-36), and between ₹1.17 per kWh and ₹10.58 per kWh from hydro stations (Table-37).

Table-36: Tariff of Central Thermal Power Stations, 2021-22

Sl No	Name of the Station	Installed Capacity (MW) as on 31.03.2022	Normative Fixed Charges (₹ /kWh) @ 85% SG	ECR (₹/kWh)	Total Tariff (₹/kWh)
NTPC Generating Stations					
1	Singrauli STPS	2000	0.65	1.39	2.04
2	Rihand STPS-I	1000	0.84	1.41	2.25
3	Rihand STPS-II	1000	0.7	1.41	2.11
4	Rihand STPS-III	1000	1.44	1.39	2.83
5	FGUTPS Unchahar-I	420	1.08	3.04	4.12
6	FGUTPS Unchahar-II	420	1.01	3.06	4.06
7	FGUTPS Unchahar-III	210	1.34	3.08	4.42
8	FGUTPS Unchahar-IV	500	1.55	2.91	4.47
9	Tanda-I	440	1.26	3.31	4.57
10	Tanda-II	660	1.6	2.59	4.19
11	NCTPS Dadri-I	840	0.97	3.32	4.29
12	NCTPS Dadri-II	980	1.43	3.28	4.71
13	Korba STPS-I&II	2100	0.68	1.39	2.07
14	Korba STPS-III	500	1.38	1.36	2.75
15	Sipat STPS-I	1980	1.3	1.39	2.69
16	Sipat STPS-II	1000	1.23	1.44	2.68
17	Vindhyachal STPS-I	1260	0.85	1.66	2.52
18	Vindhyachal STPS-II	1000	0.7	1.59	2.29
19	Vindhyachal STPS-III	1000	1.04	1.57	2.62
20	Vindhyachal STPS-IV	1000	1.56	1.56	3.12
21	Vindhyachal STPS-V	500	1.67	1.6	3.27
22	Lara	1600	1.67	2.03	3.7
23	Solapur	1320	1.72	3.06	4.78
24	Mouda STPS-I	1000	1.87	2.71	4.59
25	Mouda STPS-II	1320	1.48	2.9	4.39
26	Gadarwara	1600	2.08	2.5	4.58
27	Khargone	1320	1.81	2.71	4.52
28	Talcher STPS-I	1000	0.96	2	2.95
29	Talcher STPS-II	2000	0.71	1.97	2.69
30	Talcher TPS	460	1.44	1.87	3.31
31	Darlipali	800	2.11	1.08	3.2
32	Kahalgaon STPS-I	840	1.05	2.23	3.28
33	Kahalgaon STPS-II	1500	1.09	2.11	3.19
34	Farakka STPS-I&II	1600	0.82	2.7	3.52
35	Farakka STPS-III	500	1.49	2.66	4.14

36	Barh STPS-II	1320	1.84	2.65	4.48
37	Barauni-I	220	0.73	3.38	4.11
38	Barauni-II	250	2.43	2.64	5.06
39	Bongaigaon TPS	750	2.4	3.37	5.77
40	Ramagundam STPS-I&II	2100	0.73	2.4	3.13
41	Ramagundam STPS-III	500	0.77	2.33	3.1
42	Simhadri STPS-I	1000	0.94	2.96	3.89
43	Simhadri STPS-II	1000	1.52	2.93	4.44
44	Kudgi	2400	1.66	3.15	4.81
NTPC Gas Stations Tariff for 2021-22					
45	Faridabad	431.59	0.74	2.68	3.42
46	Auraiya	663.36	0.63	3.51	4.15
47	Dadri	829.78	0.58	3.13	3.71
48	Anta	419.33	0.71	3.76	4.47
49	Gandhar	657.39	1.06	2.13	3.18
50	Kawas	656.2	0.84	2	2.83
51	Kayamkulam	359.58	1.14	6.71	7.85
NTPC -JV Stations Tariff for 2021-22					
52	MUNPL, Meja	1320	2.09	2.56	4.64
53	APCPL, Jhajjar	1500	1.62	3.25	4.87
54	NTECL, Vellur	1500	1.78	2.97	4.75
55	BRBCL, Nabinagar	750	2.37	2.31	4.68
56	NPGCL, Nabinagar	660	2.54	2.08	4.62
57	KBUNL, Kanti-I	220	1.1	3.08	4.18
58	KBUNL, Kanti-II	390	2.74	2.64	5.38
NLC Stations					
59	TS-II St.1	630	2.661	0.71	3.371
60	TS-II St.2	840	2.623	0.736	3.359
61	TPS-I Exp.	420	2.454	0.965	3.419
62	BTPS	250	1.077	2.308	3.385
63	TPS-2 Exp.	500	2.562	2.309	4.871
64	NTPL	1000	2.842	1.553	4.395
65	NNTPP	1000	2.193	1.804	3.997
66					
DVC					
66	DTPS	210	3.927	2.591	6.518
67	MTPS (1-3)	630	3.198	1.189	4.387
68	MTPS (4)	210	3.185	0.904	4.089
69	MTPS (5-6)	500	3.044	1.524	4.568

70	MTPS (7-8)	1000	2.9	1.653	4.553
71	CTPS (7-8)	500	2.675	1.538	4.213
72	DSTPS (1-2)	1000	2.946	1.897	4.843
73	KTPS (1-2)	1000	2.657	1.722	4.379
74	RTPS (1-2)	1200	3.067	2.162	5.229
75	BTPS A	500	2.273	2.53	4.803
		76			
PPCL Bawana					
76	PPCL Bawana TPS	1371.2	1.32	3.15	4.47
NEEPCO Gas PLants					
77	AGBP	291	1.387	2.041	3.428
78	AGTCCP	135	1.893	1.803	3.696
79	TGBP	101	2.053	2.981	5.034
ONGC Tripura Power Company Ltd., Palatana Project					
80	OTPC PALATANA	726.6	1.87	1.41	3.28

Table 37: Composite Tariff of Central Hydro Power Stations, 2021-22

Sl. No	Power Station	Installed Capacity (MW)	Annual Design Energy (MU)	Composite Tariff (including water tax for J&K) (₹ /kWh)
NHPC				
1	Bairasiul	180	779.28	2.244
2	Salal	690	3082	2.359
3	Tanakpur	94.2	452.19	3.297
4	Chamera-I	540	1664.55	2.282
5	Uri-I	480	2587.38	2.116
6	Chamera-II	300	1499.89	2.009
7	Dhauliganga	280	1134.69	2.51
8	Dulhasti	390	1906.8	5.078
9	Loktak	105	448	3.891
10	Rangit	60	338.61	3.81
11	Teesta-V	510	2572.7	2.326
12	Uri-II	240	1123.77	5.153
13	Nimoo Bazgo	45	239.33	10.578
14	Chutak	44	212.93	9.871
15	Sewa-II	120	533.53	5.484
16	Chamera-III	231	1108.17	3.94
17	Parbati-III	520	1963.29	3.079

18	TLDP-III	132	594.07	5.3
19	TLDP-IV	160	720	4.35
20	Kishanganga	330	1712.96	4.101
TEESTA URJA LIMITED				
21	Teesta -III	1200	5213.82	5.826
SJVNL				
22	Nathpa Jhakri	1500	6612	2.332
23	Rampur	412	1878.08	4.168
NEEPCO				
24	Ranganadi	405	1509.69	2.424
25	Kopili ST-I	200	1186.14	1.166
26	Kopili ST-II	25	86.3	2.767
27	Khandong	50	227.61	1.677
28	Doyang	75	227.24	6.53
29	Tuirial	60	250.63	5.15
30	Pare*	110	506.42	5
31	Kameng*	600		4
THDC				
32	Tehri	1000	2797	3.87
33	Koteshwar	400	1154.82	4.61
NHDC				
34	Indira Sagar	1000	1442.7	3.67
35	Omkareshwar	520	677.47	4.55
DVC**				
36	Maithon	63.2	NA	NA
37	Panchet	80	NA	NA
38	Taliya	4	NA	NA
IPP				
39	Karcham Wangtoo	1000	4559.77	2.868
NTPC				
40	Koldam	800	3054.79	4.902

*Mutually agreed by NEEPCO and its beneficiaries.
** Updated information on hydro generating stations of DVC is not received
NA: Not Available

***

Chapter-V

Trading of Renewable Energy Certificates

1. Renewable Energy Certificate Mechanism

The Renewable Energy Certificate (REC) mechanism is a market-based instrument, to promote renewable sources of energy and development of market in electricity. The REC mechanism provides an alternative voluntary route to a generator to sell his electricity from renewable sources just like conventional electricity and sell the green attribute separately to obligated entities to fulfill their Renewable Purchase Obligation (RPO). Such a generator can either opt to enter into a Power Purchase Agreement for sale at preferential full cost tariff to a distribution licensee or can opt to take the REC route for such untied capacity. If he opts for the REC route, he can sell his electricity to a distribution licensee such as a conventional source-based generation at an average power purchase cost. Or, he can sell to a third party, that is, to an open access consumer at mutually settled prices, or even on power exchanges. On every one-megawatt hour of such electricity generated, he is entitled to get one REC from the central registry (which is regulated by the CERC) after getting registered once with this registry. Such registration requires prior accreditation with the state nodal agency for verifying the source of generation, capacity, and grid metering.

There are two categories of RECs, namely solar and non-solar, to meet the RPO of the corresponding category. This is because the cost of solar-based generation is very high compared to all other sources. The RE generator as an eligible entity shall apply for issuance of REC within 6 months from the month in which RE power was generated and injected into the grid. The central agency shall issue the RECs to the eligible entity within 15 working days from the date of physical receipt of the application by the eligible entity. The issued REC is valid for 1095 days. It is to be sold on power exchanges regulated by CERC, which also fixes a price band for exchange of REC (the band of forbearance price and floor price) to protect the interests of obligated entities and generators, respectively. Obligated entities can fulfill RPO by purchasing renewable electricity at full cost preferential tariff or by purchasing REC equivalent to their RPO.

Voluntary buyers can also purchase REC. Regulatory charge for shortfall of RPO compliance is at the rate of forbearance price.

The Central Electricity Regulatory Commission (Terms and Conditions for recognition and issuance of Renewable Energy Certificate for Renewable Energy Generation) Regulations, 2010 were issued on 14th January, 2010 for the development of market in power from non-conventional energy sources by issuance of transferable and saleable credit certificates. The CERC has nominated NLDC as the Implementing Agency (for the Central Registry), which prepares procedures and a web-based platform for the REC mechanism. The REC mechanism was formally launched on 18th November 2010.

2. Trading of Renewable Energy Certificates

Trading of RECs is being undertaken on Power Exchanges on the last Wednesday of every month. In the event of a bank holiday on the last Wednesday of any month, trading shall take place on the next bank working day. If there are other exigencies warranting change in the day for trading, the Central Agency can make such change as considered necessary under intimation to all concerned. The bidding window is kept open on the Power Exchanges designated for dealing in the RECs from 13:00 Hrs to 15:00 Hrs on the day of trading.

One REC is equivalent to 1 MWh of electricity injected into the grid from renewable energy sources. The REC is exchanged only in the power exchanges approved by CERC within the band of a floor price and forbearance (ceiling) price as notified by CERC from time to time (Table-38).

Table-38: Floor and Forbearance Price applicable for REC Transactions

Applicable Period	Floor Price (₹/MWh)		Forbearance Price (₹/MWh)	
	Solar	Non-Solar	Solar	Non-Solar
w.e.f 1st June 2010	12000	1500	17000	3900
w.e.f 1st April 2012	9300	1500	13400	3300
w.e.f 1st March 2015	3500	1500	5800	3300
w.e.f 1st April 2017	1000	1000	2400	3000

The first REC trading session was held on power exchanges in March 2011. The growth of RECs transacted on power exchanges in the last 10 years is given in Table-39. As may be seen in the table, the number of RECs transacted increased significantly from 10.15 lakh in 2011-12 to 162.00 lakh in 2017-18 and then declined to 89.28 lakh in 2019-20. As per Hon'ble APTEL Order trading sessions of RECs at both the Power Exchanges remained suspended from Jul'20 to Oct'21 and resumed from Nov'21 as per Hon'ble APTEL Order dated 09.11.2021. During 2021-22, a total of 84.60 RECs were transacted on the power exchanges.

Table-39: Growth of Renewable Energy Certificates transacted on Power Exchanges, 2011-12 to 2021-22

Year	Number of buyers	Number of sellers	Number of RECs transacted (Lakhs)	% increase in Number of RECs Transacted
2011-12	397	197	10.15	-
2012-13	802	683	25.90	155%
2013-14	1083	1044	27.49	6%
2014-15	821	1378	30.62	11%
2015-16	1332	1512	49.55	62%
2016-17	1760	1588	64.88	31%
2017-18	1140	1088	162.00	150%
2018-19	988	830	126.00	-22%
2019-20	830	820	89.28	-29%
2020-21*	277	523	9.21	-90%
2021-22 *	541	749	84.60	819%

Note: The buyers/sellers can transact through any of the Power Exchange.

** As per Hon'ble APTEL Order trading sessions of RECs at both the Power Exchanges was suspended from Jul'20 to Oct'21 and resumed from Nov'21 as per Hon'ble APTEL Order dated 09.11.2021.*
Source: NLDC

Table-40 shows the demand and supply of RECs, i.e., the gap between the volume of buy and sell bids of RECs on power exchanges during 2012-13 to 2021-22. As may be observed from the table, the volume of buy bid as a percentage of volume of sell bid initially showed a declining trend from 2012-13 to 2016-17 followed by an increasing trend from 2017-18 to 2019-20 in both the power exchanges because of change in demand for both Solar and Non-Solar RECs.

Table-40: Demand and Supply of RECs on Power Exchanges, 2012-13 to 2021-22

Year	IEX			PXIL		
	Volume of Buy Bid of RECs (Lakhs)	Volume of Sell Bid of RECs (Lakhs)	Volume of Buy Bid as % of volume of Sell Bid	Volume of Buy Bid of RECs (Lakhs)	Volume of Sell Bid of RECs (Lakhs)	Volume of Buy Bid as % of volume of Sell Bid
Solar						
2012-13	0.77	0.14	549%	0.12	0.05	265%
2013-14	0.54	5.86	9%	0.14	1.35	10%
2014-15	1.01	37.00	3%	0.63	33.46	2%
2015-16	4.65	227.67	2%	1.83	93.80	2%
2016-17	4.04	323.70	1%	1.53	147.66	1%
2017-18	0.89	34.99	3%	1.20	13.68	9%
2018-19	86.45	152.51	57%	44.46	99.85	45%
2019-20	71.49	19.45	367%	26.80	8.12	330%
2020-21*	1.46	2.44	60%	0.37	0.71	51%
2021-22*	38.73	30.01	129%	6.21	5.58	111%
Non-Solar						
2012-13	24.35	91.85	27%	6.55	24.90	26%
2013-14	12.71	251.65	5%	14.11	172.33	8%
2014-15	14.47	553.25	3%	14.51	550.88	3%
2015-16	26.73	889.92	3%	16.34	644.01	3%
2016-17	42.15	981.50	4%	17.16	596.37	3%
2017-18	94.17	635.09	15%	67.89	324.13	21%
2018-19	88.05	60.43	146%	37.82	16.53	229%
2019-20	91.87	94.72	97%	46.71	48.15	97%
2020-21*	5.78	41.70	14%	1.91	21.05	9%
2021-22*	50.84	90.58	56%	21.52	40.41	53%

** As per Hon'ble APTEL Order trading sessions of RECs at both the Power Exchanges was suspended from Jul'20 to Oct'21 and resumed from Nov'21 as per Hon'ble APTEL Order dated 09.11.2021*

The volume and price of RECs transacted on both the power exchanges from 2012-13 to 2021-22 is provided in Table-41. It can be observed from the table that the the volume of both solar and non-solar RECs transacted on the power exchanges in general shown an upward trend from 2012-13 to 2021-22, except for a few years. Similarly, the weighted average of market clearing price of the RECs witnessed a downward trend over the years. The increase in the volume of RECs transacted on power exchanges can be attributed to the increase in RPO compliance whereas decline in the price of RECs can be attributed to the demand and supply of RECs and the REC regulations issued by CERC from time to time. During the last two years (2020-21 and

2021-22), trading sessions of RECs at both the Power Exchanges remained suspended from Jul'20 to Oct'21 as per Hon'ble APTEL Order. Trading was later resumed from Nov'21 as per Hon'ble APTEL Order dated 09.11.2021.

The market clearing volume of Solar RECs transacted on both power exchanges increased from 0.14 lakhs in 2012-13 to 13.63 lakhs in 2021-22, whereas the weighted average of market clearing price of these RECs declined from ₹ 12740/MWh in 2012-13 to ₹ 2195/MWh in 2021-22. The market clearing volume of Non-Solar RECs transacted on both power exchanges increased from 25.76 lakhs in 2012-13 to 70.98 lakhs in 2021-22, whereas the weighted average of market clearing price of these RECs declined from ₹ 1692/MWh in 2012-13 to ₹ 1000/MWh in 2021-22.

Table-41: Volume and Price of RECs transacted on Power Exchanges, 2012-13 to 2021-22

Month	IEX		PXIL		Total	
	Volume of RECs (MWh) in Lakhs	Weighted Average Price of RECs (₹/MWh)	Volume of RECs (MWh) in Lakhs	Weighted Average Price of RECs (₹/MWh)	Volume of RECs (MWh) in Lakhs	Weighted Average Price of RECs (₹/MWh)
Solar						
2012-13	0.10	12782	0.04	12615	0.14	12740
2013-14	0.53	9383	0.14	9668	0.67	9441
2014-15	1.01	3725	0.63	4756	1.64	4121
2015-16	4.65	3500	1.83	3500	6.48	3500
2016-17	4.04	3500	1.53	3500	5.57	3500
2017-18	0.89	1000	1.20	1000	2.08	1000
2018-19	46.59	1113	25.36	1067	71.95	1097
2019-20	17.11	2293	6.04	2292	23.15	2293
2020-21*	1.19	1491	0.33	1290	1.52	1447
2021-22*	11.21	2201	2.42	2166	13.63	2195
Non-Solar						
2012-13	19.81	1731	5.95	1564	25.76	1692
2013-14	12.71	1500	14.11	1500	26.82	1500
2014-15	14.47	1500	14.51	1500	28.98	1500
2015-16	26.73	1500	16.34	1500	43.07	1500
2016-17	42.15	1500	17.16	1500	59.31	1500
2017-18	92.41	1480	67.35	1487	159.76	1483
2018-19	41.22	1298	10.77	1274	51.98	1293

2019-20	43.16	1634	21.71	1659	64.88	1642
2020-21*	5.78	1000	1.91	1000	7.69	1000
2021-22*	49.57	1000	21.41	1000	70.98	1000

** As per Hon'ble APTEL Order trading sessions of RECs at both the Power Exchanges was suspended from Jul'20 to Oct'21 and resumed from Nov'21 as per Hon'ble APTEL Order dated 09.11.2021*

Consequent to the revised floor and forbearance price issued by CERC vide order dated 30.03.2017, the Supreme Court had put stay on trading of RECs. While trading of Non-Solar RECs was allowed conditionally from July 2017 onwards, trading of Solar RECs was suspended till March 2018. After the APTEL Judgement, vide order dated 12.04.2018, the trading of Solar RECs resumed after a gap of one year, i.e., in the month of April, 2018. As majority of the RECs expired/were likely to expire soon, the CERC extended the validity of the RECs up to 31.03.2018. Keeping in view the large inventory of RECs, the CERC further extended the validity of the RECs up to 31st December 2019 and up to 31st March 2020 through its order dated 30.04.2019 and 30.12.2019, respectively.

In May 2018, Ministry of New and Renewable Energy (MNRE), vide order dated 22.05.2018, created the RPO Compliance Cell, with a function to coordinate with States, CERC and SERCs on matters relating to RPO compliance and taking up non-compliance issues with appropriate authorities. MNRE has up-scaled the target of renewable energy capacity to 175 GW by 2022 which includes 100 GW from solar, 60 GW from wind, 10 GW from bio- resources and 5 GW from small hydro-power. The generation target is also coupled with Renewable Purchase Obligation (RPO) to be met by distribution licensees and open access consumers.

In order to accelerate the growth of hydro power sector, the Ministry of Power (MoP) on 08.03.2019, declared Large hydro Power Plants (LHPs) having installed capacity of more than 25 MW as renewable energy source. The Ministry notified Hydro Purchase Obligation (HPO) as a separate category to Non-Solar RPO for procuring power from LHPs. The Ministry also issued a revised trajectory of RPO for FY 21-22, including long-term trajectory for HPO on 29.01.2021 (Table 42).

Table-42: Long-term Growth Trajectory of RPOs

Year	Solar RPO	Non-Solar RPO			Total RPO
		HPO	Other Non-Solar RPO	Total Non-Solar RPO	
2019-20	7.25%	-	10.25%	10.25%	17.50%
2020-21	8.75%	-	10.25%	10.25%	19.00%
2021-22	10.50%	0.18%	10.50%	10.68%	21.18%
2022-23	To be specified later	0.35%	To be specified later	To be specified later	To be specified later
2023-24		0.66%			
2024-25		1.08%			
2025-26		1.48%			
2026-27		1.80%			
2027-28		2.15%			
2028-29		2.51%			
2029-30		2.82%			

Source: Ministry of Power

***

List of Transmission Licensees as on 31.03.2022

S.No.	Name of Licensee	Date of grant of licence
1	Powerlinks Transmission Ltd.	13.11.2003
2	Torrent Power Grid Ltd	16.05.2007
3	Jaypee Powergrid Ltd	01.10.2007
4	Essar Power Transmission Company Ltd.	10.04.2008
5	Parbati Koldam Transmission Company Ltd	15.09.2008
6	Western Region Transmission (Maharashtra) (P) Ltd	30.12.2008
7	Western Region Transmission (Gujrat) (P) Ltd	30.12.2008
8	Teestavalley Power Transmission Ltd	14.05.2009
9	North East Transmission Company Ltd	16.06.2009
10	East - North Inter - Connection Company Ltd.	28.10.2010
11	Talcher - II Transmission Company Ltd.	08.11.2010
12	Cross Border Power Transmission Company Ltd	01.12.2010
13	North Karanpura Transmission Company Ltd.	16.12.2010
14	Jindal Power Ltd	09.05.2011
15	Raichur Sholapur Transmission Company Ltd	24.08.2011
16	Jabalpur Transmission Company Ltd	12.10.2011
17	Bhopal Dhule Transmission Company Ltd	12.10.2011
18	Powergrid NM Transmission Ltd	20.06.2013
19	Torrent Energy Ltd	16.07.2013
20	Adani Transmission (India) Ltd	29.07.2013
21	Aravali Power Co. Ltd.	07.11.2013
22	Kudgi Transmission Ltd	07.01.2014
23	Powergrid Vizag Transmission Ltd	08.01.2014
24	Darbhanga - Motihari Transmission Company Ltd	30.05.2014
25	Purulia & Kharagpur Transmission Company Ltd	30.05.2014
26	Patran Transmission Company Ltd	14.07.2014
27	Powergrid Unchahar Transmission Ltd	21.07.2014
28	RAPP Transmission Company Ltd	31.07.2014
29	NRSS XXXI (B) Transmission Ltd	25.08.2014
30	Powergrid Kala Amb Transmission Ltd (NRSS XXXI (A) Transmission Ltd)	04.09.2014
31	NRSS XXIX Transmission Ltd (Sterlite)	14.11.2014
32	Powergrid Jabalpur Transmission Ltd	15.06.2015
33	DGEN Transmission Company Ltd	24.06.2015
34	Powergrid Parli Transmission Ltd (Gadarwara (B) Transmission Ltd)	10.07.2015
35	POWERGRID Warora Transmission Ltd	05.08.2015

36	Maheshwaram Transmission Ltd	23.11.2015
37	Raipur-Rajandgaon-Warora Transmission Ltd	29.02.2016
38	Chhattisgarh-WR Transmission Ltd	29.02.2016
39	Sipat Transmission Ltd	07.03.2016
40	POWERGRID Southern Interconnector Transmission System Ltd	14.03.2016
41	Alipurduar Transmission Ltd	21.03.2016
42	Odisha Generation Phase-II Transmission Ltd	30.06.2016
43	Gurgaon Palwal Transmission Ltd	29.09.2016
44	Warora-Kurnool Transmission Ltd	29.09.2016
45	North Karanpura Transco Ltd	29.09.2016
46	Khargone Transmission Ltd	17.11.2016
47	NRSS XXXVI Transmission Ltd	07.12.2016
48	NER-II Transmission Ltd	20.06.2017
49	Powergrid Medinipur Jeerat Transmission Ltd	20.06.2017
50	Kohima-Mariani Transmission Ltd	10.07.2017
51	Powergrid Mithilanchal Transmission Limited (ERSS XXI Transmission Ltd)	24.04.2018
52	Goa - Tamnar Transmission Project Ltd	13.07.2018
53	Fatehgarh-Bhadla Transmission Ltd	27.08.2018
54	Powergrid Varanasi Transmission Ltd (WR-NR Power Transmission Ltd)	27.08.2018
55	Powergrid Khetri Transmission System Limited	19.12.2019
56	Bikaner-Khetri Transmission Limited	27.12.2019
57	Udupi Kasargode Transmission Limited (UKTL)	24.01.2020
58	WRSS XXI (A) Transco Limited	24.01.2020
59	Power Grid Bhuj Transmission Limited (PBTL)	03.03.2020
60	Lakadia Banaskantha Transco Limited	03.03.2020
61	Powergrid Ajmer Phagi Transmission Limited (PAPTL)	04.03.2020
62	Powergrid Fatehgarh Transmission Limited (PFTL)	04.03.2020
63	Lakadia Vadodara Transmission Project Limited (LVTPL)	04.03.2020
64	Jam Khambhaliya Transco Limited	24.03.2020
65	Vapi-II North Lakhimpur Transmission Limited	01.04.2021
66	Powergrid Ramgarh New Transmission Limited	31.05.2021
67	Powergrid Bikaner Transmission System Limited (Bikaner-II Bhiwadi Transco Limited)	15.07.2021
68	NRSS XXXI (A) Transmission Limited, (Now known as Powergrid Kala Amb Transmission Limited - on the RTM route)	22.03.2022
69	Koppal-Narendra Transmission Limited	28.03.2022

List of Trading Licensee as on 31.03.2022

Sr. No.	Name of Trading Licensee	Date of Issue of License	Category of License
1	Tata Power Trading Company Ltd	09.06.2004	I
2	Adani Enterprises Ltd	09.06.2004	I
3	PTC India Ltd	30.06.2004	I
4	NTPC Vidyut Vyapar Nigam Ltd	23.07.2004	I
5	National Energy Trading & Services Ltd	23.07.2004	III
6	Instinct Infra & Power Ltd	07.09.2005	III
7	Essar Electric Power Development Corporation Ltd.*	14.12.2005	II
8	JSW Power Trading Company Ltd.	25.04.2006	IV
9	Greenko Energies (P) Ltd	22.01.2008	III
10	Ambitious Power Trading Company Ltd	16.09.2008	IV
11	RPG Power Trading Company Ltd	23.09.2008	II
12	GMR Energy Trading Ltd	14.10.2008	I
13	Shyam Indus Power Solutions (P) Ltd.*	11.11.2008	III
14	Global Energy (P) Ltd.**	28.11.2008	I
15	Knowledge Infrastructure Systems (P) Ltd	18.12.2008	IV
16	Kreate Energy (I) Pvt. Ltd.	12.02.2009	II
17	Shree Cement Ltd	16.03.2010	IV
18	ABJA Power Pvt. Ltd.	26.04.2011	III
19	Customised Energy Solutions India (P) Ltd	08.06.2011	V
20	Statkraft Markets (P) Ltd	21.06.2012	I
21	Manikaran Power Ltd	29.06.2012	I
22	Arunachal Pradesh Power Corporation (P) Ltd	11.09.2012	II
23	Vedprakash Power (P) Ltd.*	19.08.2013	IV
24	Solar Energy Corporation of India	01.04.2014	I
25	Saranyu Power Trading Private Limited	10.02.2015	V
26	Gita Power & Infrastructure (P) Ltd	20.10.2015	III
27	Phillip Commodities India Pvt. Ltd.	21.01.2016	IV
28	Atria Energy Services Private Limited	20.06.2017	V
29	NHPC Limited	23.04.2018	I
30	NLC India Ltd.	13.07.2018	I
31	Refex Energy Ltd.	30.08.2018	I
32	NTPC Limited	08.07.2019	I
33	Amp Energy Markets India Pvt. Ltd.	15.04.2021	V
34	Altilium Energies Pvt. Ltd.	23.05.2021	V
35	Shubheksha Advisors Pvt. Ltd.	31.07.2021	V

36	Reneurja Power LLP	31.07.2021	V
37	ReNew Energy markets Pvt. Ltd.	28.11.2021	IV
38	Shell Energy Marketing and Trading India Pvt. Ltd.	22.12.2021	V
39	SJVN Limited	10.01.2022	I
40	Instant Ventures Pvt. Ltd.	09.02.2022	V
41	Refex Industries Ltd.	21.03.2022	I
42	Ideal Energy Solutions Pvt. Ltd.	22.03.2022	V
43	AEI New Energy Trading Pvt. Ltd.	25.03.2022	III

** License category is provisional due to pending litigation(s).*

*** Corporate Insolvency Resolution Process has been initiated as per the directions of the Hon'ble Supreme Court dated 31-03-2022.*

Historical Volatility Formula:

$$\sigma = \sqrt{\frac{1}{(n-1)}\sum_{y=1}^{n}(\ln\frac{y_i}{y_{i-1}} - \mu)^2}$$

where

$$\mu = \frac{1}{n}\sum_{y=1}^{n}(\ln\frac{y_i}{y_{i-1}})$$

1. Daily prices returns = Ln (y_i / y_{i-1}).
2. y_i is price for today; y_{i-1} is price on previous day.
3. Ln is natural logarithm
4. n is the number of observations
5. u is the average daily returns

Herfindahl-Hirschman Index (HHI)

Formula for computing the HHI is as under:

$$\mathbf{HHI} = \sum_{i=1}^{N} s_i^2$$

where, s_i is the market share of firm i in the market, and N is the number of firms.

The Herfindahl-Hirschman Index (HHI) ranges from 1/N to 1, where N is the number of firms in the market. Equivalently, if percentages are used as whole numbers, as in 75 instead of 0.75, the index can range up to 100^2 or 10,000.

- HHI below 0.01 (or 100) indicates a highly competitive index.
- HHI below 0.15 (or 1,500) indicates an unconcentrated index.
- HHI between 0.15 to 0.25 (or 1,500 to 2,500) indicates moderate concentration.
- HHI above 0.25 (above 2,500) indicates high concentration.

There is also a normalized Herfindahl index. Whereas, the Herfindahl index ranges from 1/N to 1, the normalized Herfindahl index ranges from 0 to 1.

Central Electricity Regulatory Commission
3rd & 4th Floor, Chanderlok Building
36, Janpath, New Delhi-110001
Phone: +91-11-23353503, Fax: +91-11-23753923
www.cercind.gov.in