Report on Short-term Power Market in India: 2018-19

Economics Division
Central Electricity Regulatory Commission

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Preface

The Electricity Act, 2003 consolidated 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, 2004, Open Access Regulations, 2004 and Power Market Regulations, 2010. 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 per cent of the total electricity generation in India in the year 2018-19.

The annual report on short-term power market in India provides a snapshot on the short-term transactions of electricity through different instruments used by various market participants. The Central Electricity Regulatory Commission brings out the report to keep market participants and other stakeholders aware and updated on the state of the power market. 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. It also covers 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 confident that market participants and stakeholders will find the Report on Short-term Power Market in India, 2018-19 useful.

Abbreviations

Abbreviation	Expanded Version
AC	Alternating Current
ACE	Area Control Error
AGC	Automatic Generation Control
APL	Above Poverty Line
APPCC	Andhra Pradesh Power Coordination Committee
APCPDCL	Andhra Pradesh Central Power Distribution Company Limited
APSPDCL	Andhra Pradesh Southern Power Distribution Company Limited
APTEL	Appellate Tribunal For Electricity
AT&C	Aggregate Technical and Commercial
Block	15 Minutes Time Block
BYPL	BSES Yamuna Power Limited
BSPHCL	Bihar State Power Holding Company Limited
BU	Billion Units (Billion kWh)
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CGS	Central Generating Station
Ckm	Circuit km
CPP	Captive Power Producer/Plant
CSPDCL	Chattisgarh State Power Distribution Company Limited
CTU	Central Transmission Utility
DAM	Day Ahead Market
DDUGJY	Deendayal Upadhyaya Gram Jyoti Yojana
DISCOMs	Distribution Companies
DSM	Deviation Settlement Mechanism
DVC	Damodar Valley Corporation
ER	Eastern Region
FCAS	Frequency Control Ancillary Services
FGUTPP	Firoz Gandhi Unchahar Thermal Power Project
FRAS	Fast Response Ancillary Services
GOHP/GoHP	Government of Himachal Pradesh

Abbreviation	Expanded Version
GPS	Gas Power Station
GUVNL	Gujarat Urja Vikas Nigam Limited
GW	Giga Watts
HEP	Hydro Electric Project
HHI	Herfindahl-Hirschman Index
HPP	Hydroelectric Power Plant
HPPC	Haryana Power Purchase Centre
HPSEB	Himachal Pradesh State Electricity Board
HVDC	High-Voltage Direct Current
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
JIPTL	Jindal India Thermal Power Limited
J&K PDD	Jammu & Kashmir Power Development Department
JVVNL	Jaipur Vidyut Vitran Nigam Limited
KSEB	Kerala State Electricity Board
KV	Kilovolt
kWh	Kilo Watt Hour
LDP	Low Dam Project
LTA	Long Term Access
Ltd	Limited
MCP	Market Clearing Price
MPDCL	Meghalaya Power Distribution Corporation Limited
MPPGCL	Madhya Pradesh Power Generating Company Limited
MPPMCL	MP Power Management Company Limited
MPPTCL	MP Power Trading Corporation Limited
MSEDCL	Maharashtra State Electricity Distribution Company Limited
MU	Million Units
MVA	Mega Volt Ampere
MW	Mega Watts
MWh	Mega Watt Hour

Abbreviation	Expanded Version
NCAS	Network Control Ancillary Services
NCTP	National Capital Thermal Power Plant
NEEPCO	North Eastern Electric Power Corporation Limited
NER	North Eastern Region
NHDC	National Hydro Development Corporation Limited
NHPC	National Hydro-Electric Power Corporation Limited
NLC	Neyveli Lignite Corporation Limited
NLDC	National Load Dispatch Centre
NR	Northern Region
NRSS	Northern Region Strengthening Scheme
NSGM	National Smart Grid Mission
NTPC	National Thermal Power Corporation Limited
OA	Open Access
OAC	Open Access Consumer
OTP	Other than RTC and Peak period
OTPC	ONGC Tripura Power Company
PFC	Power Finance Corporation
PGCIL	Power Grid Corporation of India Limited
POC	Point of Connection
POSOCO	Power System Operation Corporation Limited
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
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RGPPL	Ratnagiri Gas and Power Private limited
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

Abbreviation	Expanded Version
S1	Southern Region 1
S2	Southern Region 2
S3	Southern Region 3
SEB	State Electricity Board
SEIL	Sembcorp Energy India Limited
SGPL	Sembcorp Gayatri Power Limited
SJVNL	Satluj Jal Vidyut Nigam Limited
SRAS	System Restart Ancillary Services
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
TPCIL	Thermal Powertech Corporation of India Limited
TPP	Thermal Power Plant
TPS	Thermal Power Station
TSPCC	Telangana State Power Coordination Committee
TSSPDCL	Telangana State Southern Power Distribution Company
UDAY	Ujwal DISCOM Assurance Yojana
UPPCL	Uttar Pradesh Power Corporation Limited
UT	Union Territory
VAE	Virtual Ancillary Entity
WBSEDCL	West Bengal State Electricity Distribution Company Ltd
WR	Western Region

Executive Summary

The report comprises of overview of the power sector, short-term power market in India, tariff of long-term sources of power and transactions of renewable energy certificates. Overview of power sector highlights electricity generation, transmission and distribution including revenue gap of state electricity distribution companies (DISCOMs)/SEBs and the measures taken by the Government of India in the recent years. The salient features of the power sector are as under:

1. Thermal energy (mainly from Coal) is an important source of electricity generation in India, contributing about 63.5% of the total installed generation capacity in 2018-19, followed by Renewable Energy Source (RES) (21.8%), Hydro (12.7%), and Nuclear (1.9%).

2. The Compound Annual Growth Rate (CAGR) of total installed generation capacity was 9% during the period from 2008-09 to 2018-19. The CAGR in RES was 19% whereas it was 8% in all other sources during the period.

3. During the period from 2008-09 to 2018-19, share of State sector in the total installed generation capacity declined from 54% to 30% and share of central sector has declined from 31% to 24%, while share of private sector increased from 15% to 46%. However, the public sector continues to be the largest owner, holding 54% share in 2018-19.

4. Gross electricity generation in India increased from 747.06 BU in 2008-09 to 1375.86 BU in 2018-19 and it increased annually at the rate of 6%.

5. The annual growth in gross electricity generation was relatively low (6%) when compared with the annual installed electricity generation capacity (9%). This could be mainly due to (i) increase in capacity from RES with low utilization factor; and (ii) decrease in PLF of thermal generation.

6. Increase in the installed capacity resulted in decrease in the demand shortage (energy and peak shortage). The energy shortage decreased from 11.1% in 2008-09 to about 0.6% in 2018-19. During the period, the peak shortage decreased from 11.9% to 0.8%.

7. During 2008-09 to 2018-19, the annual growth in the bulk transmission was 6%, while the annual growth in the transmission capacity of substations was 12%.

8. The annual transmission charges increased at CAGR of 22.21% during the period from 2011-12 to 2018-19.

9. The total electricity consumption increased from 611.29BU in 2008-09 to 1130.24BU in 2017-18(Estimated) registering an annual growth of 7.1%. During the period, per-capita consumption of electricity also increased from 734 kWh to 1149 kWh at an annual growth of 5.1%.

10. 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 ₹5.43/kWh and ₹4.23/kWh, respectively, in 2015-16. During the period, the revenue as percentage of cost was varying between 73% and 80%. This means, the weighted average tariff for all categories of consumers was 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 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. The report also covers analysis on tariff of long-term sources of power, and transactions of renewable energy certificates (RECs) through power exchanges. Salient features of the short-term power market are as under:

1. Of the total electricity procured in India in 2018-19, the short-term power market comprised 12%. The balance 88% of generation was procured mainly by distribution companies through long-term contracts and short-term intra-State transactions.

2. During 2009-10 to 2018-19, the volume of short-term transactions of electricity increased at a higher rate (9%) when compared with the gross electricity generation (6%).

3. In terms of volume, the size of the short-term market in India was 145.20BU in the year 2018-19. As compared to the volume of electricity transacted through short-term market in the year 2017-18 (127.62BU), this was about 14% higher.

4. Excluding DSM and direct bilateral sale between the DISCOMs, the volume of electricity transacted was 100.84BU in 2018-19. This was about 16% higher than in 2017-18. In monetary terms, the size of this segment of the short-term market was ₹43,064 crore in the year 2018-19[1], which was 42% more than in the year 2017-18. The increase in size of the market can be attributed to higher volume and higher electricity prices in 2018-19.

5. The volume of electricity transacted through power exchanges increased at an annual growth rate of 25% whereas the volume of electricity transacted through traders increased at an annual growth rate of 7% during 2009-10 to 2018-19.

6. The volume of DSM in 2018-19 increased by 4% over 2017-18. 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% in 2009-10 to 17% in 2018-19.

7. In terms of volume, the direct bilateral transactions between DISCOMs witnessed an increase of about 15% in 2018-19 as compared to 2017-18. The share of direct bilateral transactions between DISCOMs as a percentage of total short term transaction volume increased from 9% in 2009-10 to 21% in 2015-16 and then declined to 13% in 2018-19.

[1]*Excluding transactions pertaining to banking transactions.*

8. The weighted average price of electricity transacted through power exchanges was ₹4.26/kWh and through trading licensees it was ₹4.28/kWh in 2018-19. The corresponding values for the year 2017-18 were ₹3.45/kWh and ₹3.59/kWh, respectively. In the year 2018-19, the weighted average price of electricity transacted through Day Ahead Market sub-segment of the power exchanges was ₹4.22/kWh and that through Term Ahead Market sub-segment was ₹4.87/kWh.

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.

10. During 2018-19, about 96.2% of the volume of electricity transacted through traders was at a price less than ₹6/kWh. About 15.5% of the volume was transacted at a price less than ₹4/kWh.

11. During 2018-19, IEX transacted 88% of the volume of electricity at a price less than ₹6/kWh while about 58% of the volume was transacted at a price less than ₹4/kWh. During the year, PXIL transacted 90% of the volume of electricity at a price less than ₹6/kWh while about 55% of the volume was transacted at less than ₹4/kWh.

12. During 2018-19, of the total electricity bought under bilateral transactions from traders, 88.5% was on round the clock (RTC) basis, followed by 9.6% in periods other than RTC and peak (OTP) and 1.9% was during peak hours. The per unit price of electricity procured during Peak period was high (₹5.39/kWh) when compared with the price during RTC (₹4.15/kWh) and OTP (₹4.39/kWh).

13. It is observed from the block-wise and region-wise prices of electricity transacted through power exchanges in 2018-19 that the price of electricity in Southern Region (S3 region) was marginally higher than the price in other regions in IEX.

14. During 2008-09 to 2018-19, number of traders who were undertaking trading increased from 14 to 25. HHI, based on volume of electricity transacted through traders, declined

from 0.24 in 2009-10 to 0.19 in 2018-19. The concentration of market power was moderate during the period. The competition among the traders resulted in an increase in volume and decrease in prices in the short-term bilateral market.

15. The weighted average trading margin charged by the trading licensees in 2018-19 was ₹0.032/kWh, which is in line with the CERC Trading Margin Regulations, 2010.

16. The procurement of power by the industrial consumers through power exchanges began in the year 2009. In both power exchanges, Open Access industrial consumers bought 11.24BU of electricity, which formed 22% of the total day ahead volume transacted in the power exchanges during 2018-19.

17. The weighted average price of electricity bought by open access consumers at IEX and PXIL was lower (₹3.48/kWh and ₹3.27/kWh respectively) compared to the weighted average price of total electricity transacted through IEX and PXIL (₹4.22/kWh and ₹4.29/kWh respectively).

18. The year witnessed very few constraints on the volume of electricity transacted through power exchanges, mainly due to transmission congestion. During 2018-19, the actual transacted volume was about 0.92% less than the unconstrained volume. Because of congestion and the splitting of day ahead market at both the power exchanges, the congestion amount collected during the year was ₹137.52 crore.

19. NLDC, in coordidation with RLDCs, has started ancillary services operations w.e.f. April 12, 2016. In 2018-19, the NLDC has issued 5501 RRAS Up/Down Instructions on account of various triggering criteria. Of the total, there were 3898 RRAS Up Instructions and 1603 RRAS Down Instructions. Majority of the Regulation Up Instructions were on account of multiple reasons followed by trend of load met, while majority of the Regulation Down Instructions were on account of multiple reasons followed by trend of load met and high frequency.

20. The energy scheduled under Regulation UP of RRAS increased from 2212.28MU in 2016-17 to 4811.69 MU in 2018-19 showing an increase of 117%. However, the

energy scheduled under Regulation DOWN of RRAS declined from 286.00MU in 2016-17 to 685.42MU in 2018-19 showing an increase of 140%.

21. In 2018-19, the number of Solar RECs transacted on power exchanges were 71.95 lakh and the weighted average of market clearing price of these RECs was ₹1097/MWh. During the year, the number of Non-Solar RECs transacted on power exchanges were 51.98 lakh and the weighted average of market clearing price of these RECs was ₹1293/MWh.

Chapter-I

Overview of Power Sector

India's power sector is well diversified with market dynamics. Power generation ranges from conventional sources such as coal, lignite, natural gas, oil, hydro and nuclear power to non-conventional sources such as wind, solar, and agricultural and domestic waste. Electricity demand in the country has increased rapidly and is expected to rise further in the years to come. In order to meet the increasing demand for electricity in the country, the electricity supply chain consisting of generation, transmission and distribution has undergone a phase of transformation to competitiveness.

1. Generation

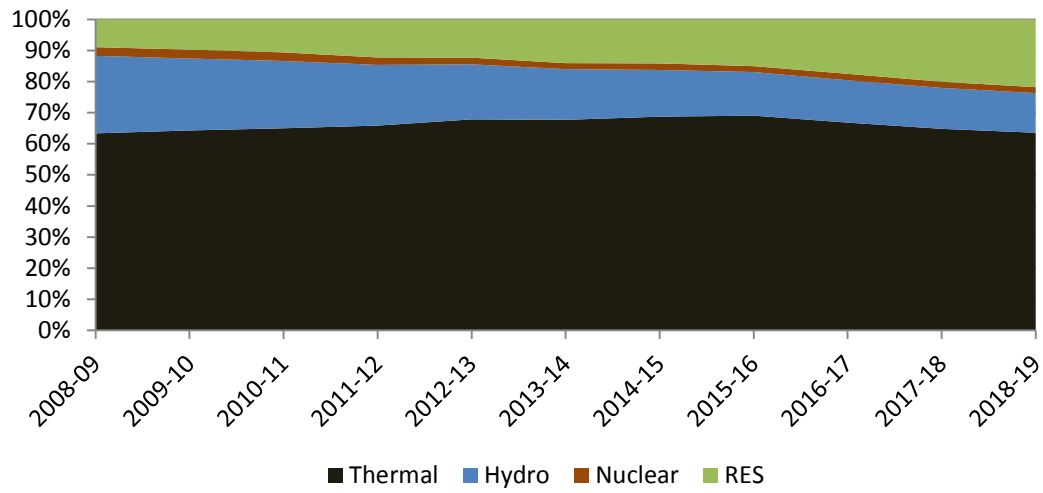
Sources of electricity generation are of two types i.e. conventional and non-conventional. The conventional sources of power generation are thermal (coal, lignite, natural gas and oil), hydro and nuclear power, and non-conventional sources of power generation (renewable energy sources) are wind, solar, agricultural and domestic waste etc. Table-1 and Figure-1 show the installed electricity generation capacity in India by source.

Table-1: Installed Electricity Generation Capacity in India (GW), 2008-09 to 2018-19

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

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

Figure-1: Installed Electricity Generation Capacity in India (%), 2008-09 to 2018-19



As can be seen in Figure-1, thermal is the most important source of electricity generation in India, contributing about 63.5% of the total capacity of generation in 2018-19, followed by Renewable Energy Source (RES) (21.8%), Hydro (12.7%) and Nuclear (1.9%). The percentage of thermal based generation capacity increased from 63.3% in 2007-08 to 69.0% in 2015-16 and then declined to 63.5% in 2018-19. During the period from 2007-08 to 2018-19, hydro based generation capacity decreased from 24.9% to 12.7%, whereas renewables based generation capacity increased from 8.9% to 21.8%. There is a sharp increase in the installed electricity generation capacity of RES when compared with all other sources. The CAGR in RES was 19% whereas it was 8% in all other sources.

The Electricity Act of 2003 liberalised the electricity generation through a license-free regime. As a result, the entry of private players into the generation segment significantly increased their share 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 includes National Thermal Power Corporation, National Hydroelectric Power Corporation, and similar organizations. (ii) State public sector undertakings/State Electricity Boards; and (iii) Private sector enterprises includes Tata Power Company Ltd, Reliance Power Ltd, Adani Power Ltd., and similar entities.

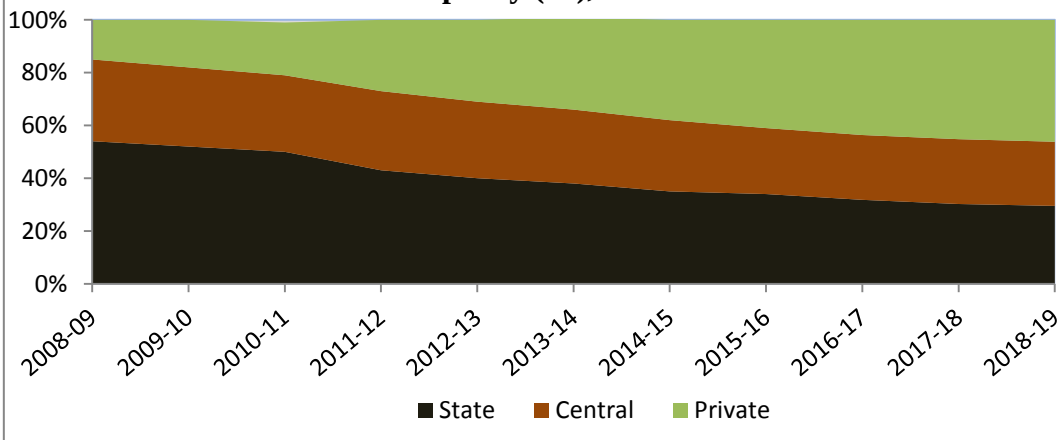
Sector-wise growth of installed generation capacity has been shown in Table-2 and Figure-2. It is observed from the table that CAGR of total installed generation capacity was 9% during the period from 2008-09 to 2018-19. During the period, the share of state sector in the total installed generation capacity has declined from 54% to 30% and the share of central sector has declined from 31% to 24%, whereas the share of private sector has increased three fold i.e. from 15% to 46%. However, the public sector continues to be the largest owner, holding 54% share in total installed generation capacity in 2018-19.

Table-2: Sector-wise Growth of Installed Electricity Generation Capacity, 2008-09 to 2018-19

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

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

Figure-2: Sector-wise Growth of Installed Electricity Generation Capacity (%), 2008-09 to 2018-19



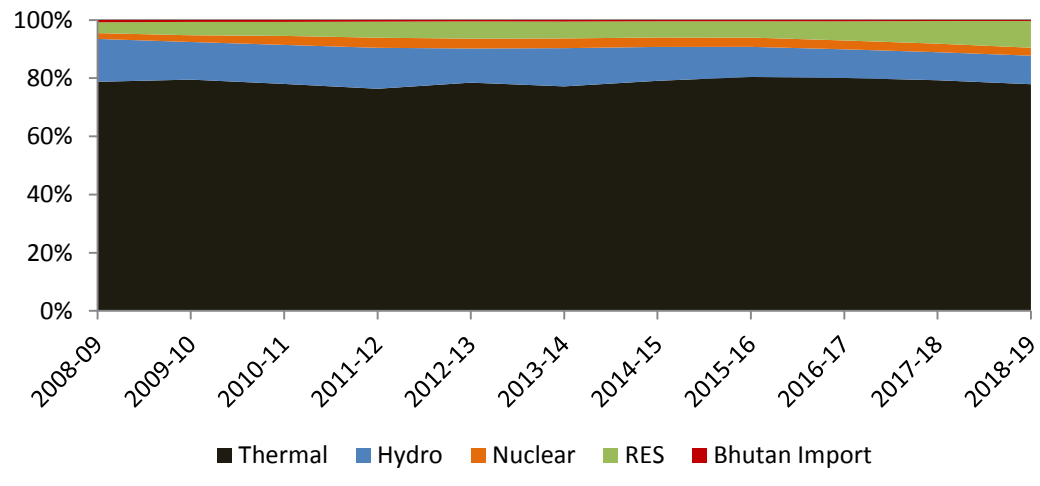
Actual Electricity generation by source is shown in Table-3 and Figure-3. It is observed from the table that gross electricity generation in India has increased from 747.06 BU in 2008-09 to 1375.86 BU in 2018-19. During the period, the gross electricity generation increased at the annual growth rate of 6%. The annual growth in gross electricity generation was low (6%) when compared with the annual installed electricity generation capacity (9%). This may be primarily due to (i) increase in capacity from RES with low utilization factor; and (ii) decrease in PLF of thermal generation.

Table-3: Gross Electricity Generation in India (BU), 2008-09 to 2018-19

Year	Thermal	Hydro	Nuclear	RES	Bhutan Import	Total
2008-09	588.28	110.10	14.93	27.86	5.90	747.06
2009-10	640.21	104.06	18.64	36.95	5.40	805.25
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	927.75
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	1026.34
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

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

Figure-3: Gross Electricity Generation in India (%), 2008-09 to 2018-19



Of all the sources, electricity genearation from thermal source (mainly coal) plays a dominat role in India. The electricity generated from thermal was varying between 76% to 80% of the total generation during 2008-09 to 2018-19. The amount of electricity generated through hydro declined from 15% to 10% where as the electricity generated from RES increased from 4% to 9%, during the period.

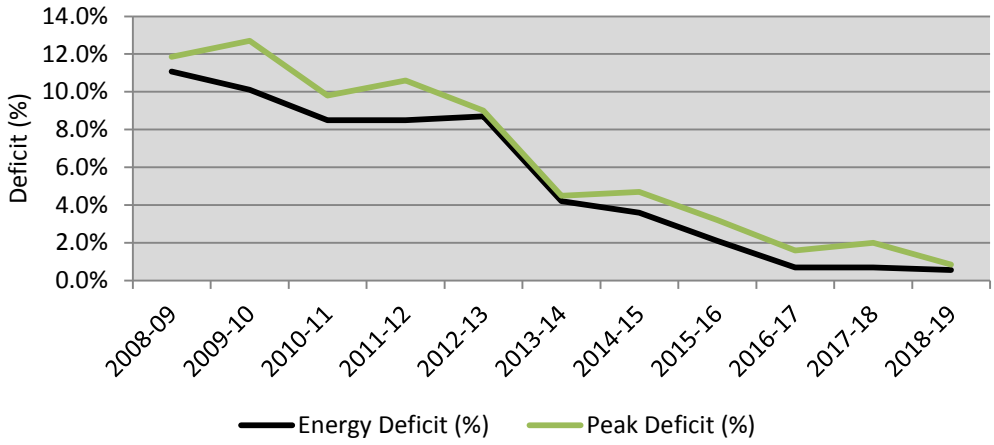
As shown in the above tables, the total installed electricity generation capacity in India has increased from 147.97 GW in 2007-08 to 356.10 GW in 2018-19. The increase in installed electricity generation capacity made an impact on the power supply position as shown in Table-4 and Figure-4. Both energy requirement and peak demand increased from 777.04 BU and 109.81 GW, respectively in 2008-09 to 1274.60 BU and 177.02 GW, respectively in 2018-19. Increase in the installed capacity resulted in decrease in the demand/shortage (energy and peak shortage). The energy and peak shortages declined from 11.1% and 11.9%, respectively in 2008-09 to about 0.6% and 0.8%, respectively in 2018-19.

Table-4: Power Supply Position in India, 2008-09 to 2018-19

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	1212.13	1203.57	0.7%	164.07	160.75	2.0%
2018-19	1274.60	1267.53	0.6%	177.02	175.53	0.8%

Source: Ministry of Power

Figure-4: Energy Deficit and Peak Deficit in India, 2008-09 to 2018-19



Electricity demand is defined in the narrowest sense because it is counted as the amount of electricity that distribution utilities buy, but not the actual demand of the millions of people in India who remain unserved or under served.

2. Transmission

The transmission sector was opened for private investments in 1998. The Central Transmission Uility (CTU) is the nodal agency for providing the 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 is responsible for inter-state transmission and development of the national grid, and it 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

[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*

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.

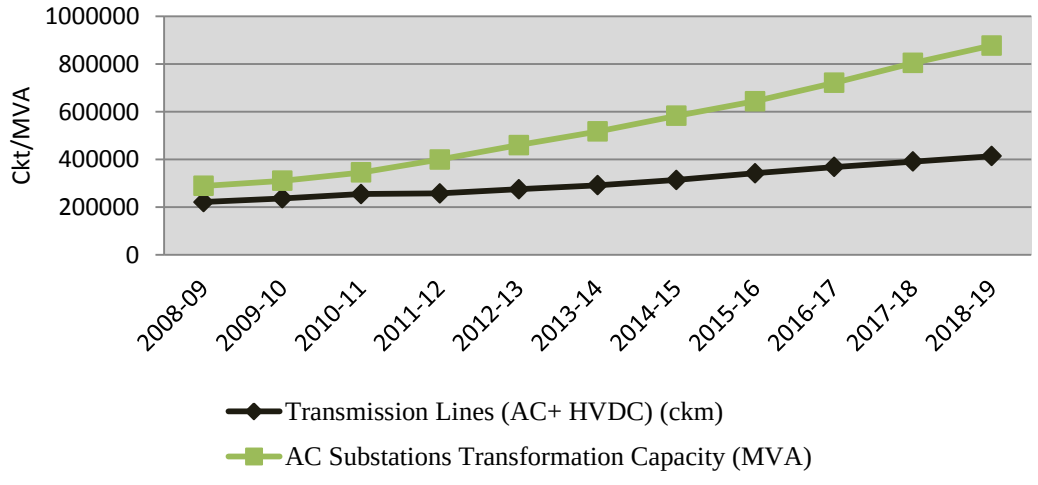
The growth of transmission lines and transmission capacity in India during 2008-09 to 2018-19 has been shown in Table-5 and Figure-5.

Table-5: Growth of Transmission System in India, 2008-09 to 2018-19

Year	Transmission Lines (AC + HVDC) (ckm)	AC Substations Transformation Capacity (MVA)
2008-09	220794	288615
2009-10	236467	310052
2010-11	254536	345513
2011-12	257481	399801
2012-13	274588	459716
2013-14	291336	517046
2014-15	313437	582600
2015-16	341551	643949
2016-17	367851	721265
2017-18	390970	804458
2018-19	413407	877163

Source: CEA, Monthly Reports.

Figure-5: Growth of Transmission System in India, 2008-09 to 2018-19



It is observed from the Table-5 that bulk transmission (transmission lines 220kv & above) has increased from 2,20,794 ckm in 2008-09 to 4,13,407 ckm in 2018-19. During the period, the transmission capacity of substations has also increased from 2,88,615 MVA to 8,77,163 MVA. The CAGR in the transmission lines and transmission capacity of substations was 6% and 12% respectively.

Table-6: Annual Transmission Charges, 2011-12 to 2018-19

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

Note: The above transmission charges are the same as used for computation of POC Charges.
Source: POSOCO

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 2018-19. The annual transmission charges increased at CAGR of 22.21% during the period. There are various reasons for increase in the transmission charges. Main reasons like the growth of transmission lines (especially at higher voltage levels), waiver of transmission charges for interstate renewable energy generators and relinquishment of long term access (LTA) have lead to increase in the annual transmission charges.

The sector is having natural monopoly as there are high sunk costs in investing in the infrastructure needed to transmit electricity, such as transmission lines. Because of these characteristics, non-public entities also face entry barriers, and private investments are allowed in transmission projects only after 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. There are about 54 Inter-state transmission licensees as on 31.3.2019 granted by CERC (Annexure-I).

3. Distribution

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 electricification, reduce aggregate technical and commercial (AT&C) losses incurred while distributing electricity, ensure the 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 1130.24 BU in 2017-18 (Estimated) at an annual growth rate of 7.1%. During the period, per capita consumption of electricity in India has increased from 734 kWh to 1149 kWh, registering an annual growth rate of 5.1%. Despite this considerable growth, the level of per capita energy consumption in India is low when compared to the international average per capita energy consumption.

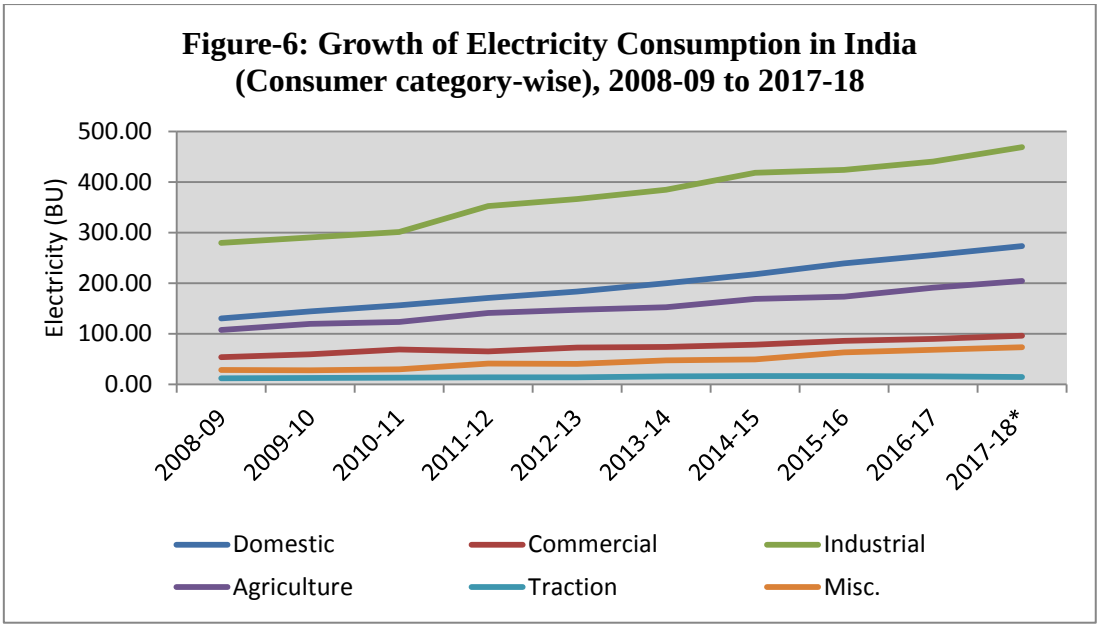
Table-7: Growth of Electricity Consumption in India (Consumer category-wise) (BU)

Year	Domes-tic	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	96.14	468.83	204.29	14.36	73.08	1130.24

* Estimated

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

Figure-6: Growth of Electricity Consumption in India (Consumer category-wise), 2008-09 to 2017-18



The AT&C Losses declined from 28.44% in 2008-09 to 18.72% in 2017-18 (UDAY Newsletter, Volume IV). More than 90% of these losses can be attributed to Transmission and Distribution Losses which correspond to electricity produced but not paid for. These losses should be reduced to the international standard of 10%.

The electricity tariffs charged by the DISCOMs are not cost reflective. 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 2015-16 in Table-8 and Figure-7.

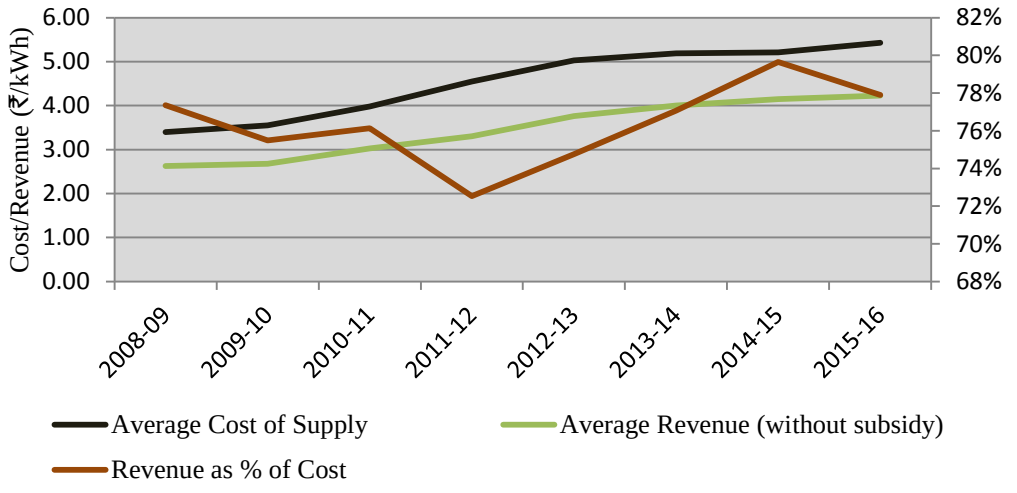
All India average cost of supply and average revenue (without subsidy) increased from ₹3.40/kWh and ₹2.63/kwh, respectively, in 2008-09 to ₹5.43/kWh and ₹4.23/kWh, respectively, in 2015-16. However the gap between the cost of supply and revenue has increased during the period. The revenue as percentage of cost of supply varied between 73% to 80%. This means, the weighted average tariff for all categories of consumers was 20% lower than the weighted average cost of supply. 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 2015-16

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%

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

Figure-7: Average Cost of Supply and Average Revenue of State Power Utilities, 2008-09 to 2015-16



The revenue gap between average cost of supply and average revenue has been reduced from ₹0.59/kWh in 2015-16 to ₹0.17/kWh in 2017-18 (UDAY Newsletter, Volume IV).

The DISCOMs in the country are trapped in a vicious cycle with huge operational losses and outstanding debt due to legacy issues. Financially stressed DISCOMs are not able to supply adequate power at affordable rates. To improve their financial health, several policy initiatives have been taken by the Union

Government during last few years like 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; (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. While the IPDS 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.

The implementation of the above mentioned programmes has led to considerable improvements in the distribution segment. However, the achievements have remained much below the targets. AT&C losses have come down to about 18.72 in 2017-18 per cent, which is still higher than the 15 per cent target. The schemes have also received a push from the UDAY which has set strict loss reduction targets for 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. Bulk purchase and sale is a regular phenomenon between DISCOMs and licensees that was construed as part of the activity of supply of electricity. It is with the enactment of the Electricity Act, that the transaction 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, trading margin regulations, power market regulations etc., of the Central Commission have facilitated power trading in an organized manner.

Bulk electric power supply in India is mainly tied in long-term contracts. The DISCOMs who have the obligation to provide electricity to their consumers mainly rely on supplies from these long-term contracts. Nevertheless, to meet the short-term requirements of the market participants, short term trading plays an important role in the power market.

A brief analysis of the short-term transactions of electricity in India has been done in this Report[4] for the year 2018-19. Here, "short-term transactions of electricity" refers to the contracts less than one year for the following trades:

[4]*Although Deviation Settlement Mechanism (DSM) is not a market mechanism, electricity transacted under DSM is often considered a part of short-term transaction. Also,*

(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 (Indian Energy Exchange Ltd (IEX) and Power Exchange India Ltd (PXIL)), and

(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; and

(vii) Ancillary services operations

2. Yearly Trends in Short-term Transactions of Electricity (2008-09 to 2018-19)

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 both Day Ahead and Term Ahead Markets,
- DSM segment, and
- Direct transactions of electricity between DISCOMs.

electricity transacted bilaterally directly between the distribution companies (without involving trading licensees or power exchanges) is also considered a part of short-term market. In the year 2018-19, the volume of DSM was about 25.13BU and that between distribution companies was about 19.23BU.

Inter-state trading licensees (traders) have been undertaking trading in electricity since 2004 and the power exchanges started operating since 2008. The two power exchanges, IEX and PXIL started their operations in June 2008 and October 2008 respectively. As of March 2019, there were 37 inter-state trading licensees (list is enclosed at Annexure-II) and two power exchanges.

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

Total volume of short-term transactions of electricity increased from 65.90BU in 2009-10 to 145.20BU in 2018-19. During the period, the volume of short-term transactions of electricity increased at a higher rate (annual growth rate of 9%) when compared with the total electricity generation[5] (annual growth rate of 6%). The volume of short-term transactions of electricity as percentage of total electricity generation varied from 9% to 12% during the period (Table-9).

Table-9: Volume of Short-term Transactions of Electricity with respect to Total Electricity Generation, 2009-10 to 2018-19

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%
2010-11	81.56	811.14	10%
2011-12	94.51	876.89	11%
2012-13	98.94	912.06	11%
2013-14	104.64	967.15	11%
2014-15	98.99	1048.67	9%
2015-16	115.23	1107.82	10%
2016-17	119.23	1157.94	10%
2017-18	127.62	1202.97	11%
2018-19	145.20	1245.32	12%

Source: NLDC & CEA

[5] *Total electricity generation excluding generation from renewable and captive power plants in India*.

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 included in the sections that follow.

2.1.1 Electricity Transacted through Traders and Power Exchanges

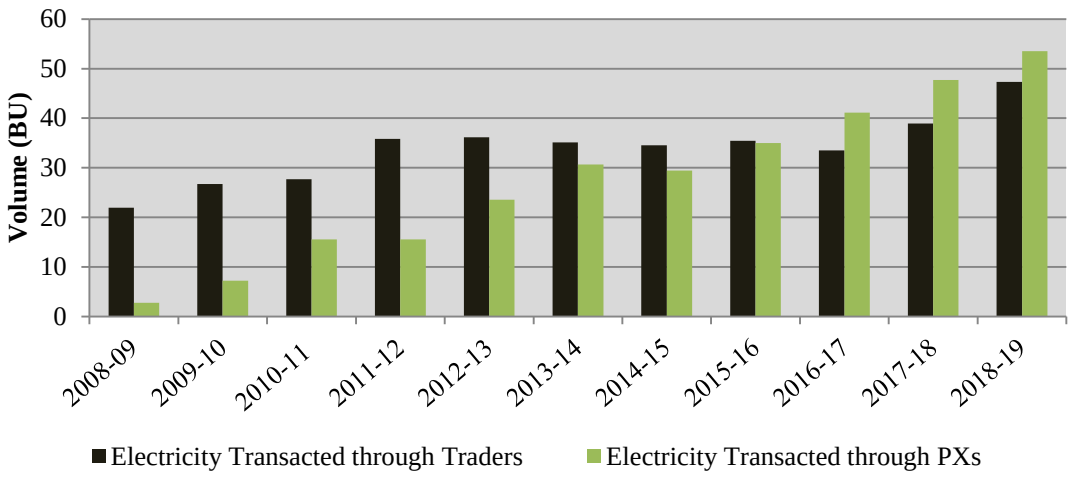
Table-10, Table-11 and Figure-8 show details of volume of electricity transacted through traders under bilateral transactions and through power exchanges for the period from 2008-09 to 2018-19. The volume of electricity transacted through traders and power exchanges increased from 24.69BU in 2008-09 to 100.84BU in 2018-19. The share of electricity transacted through traders and power exchanges as a percentage of total short-term transactions of electricity increased from 51.45% in 2009-10 to 69.45% in 2018-19. The annual growth in volume of this segment during 2009-10 to 2018-19 was 15% and the growth during 2018-19 was 16%.

Table-10: Volume of Electricity Transacted through Traders and Power Exchanges, 2008-09 to 2018-19

Year	Electricity Transacted through Traders (BUs)	Electricity Transacted through IEX (BUs)		Electricity Transacted through PXIL (BUs)		Electricity Transacted through IEX and PXIL (BUs)	Total (BUs)
		Day Ahead Market	Term Ahead Market	Day Ahead Market	Term Ahead Market		
2008-09	21.92	2.62		0.15		2.77	24.69
2009-10	26.72	6.17	0.10	0.92	0.003	7.19	33.91
2010-11	27.70	11.80	0.91	1.74	1.07	15.52	43.22
2011-12	35.84	13.79	0.62	1.03	0.11	15.54	51.38
2012-13	36.12	22.35	0.48	0.68	0.04	23.54	59.66
2013-14	35.11	28.92	0.34	1.11	0.30	30.67	65.78
2014-15	34.56	28.12	0.22	0.34	0.72	29.40	63.96
2015-16	35.43	33.96	0.33	0.14	0.58	35.01	70.43
2016-17	33.51	39.78	0.74	0.25	0.35	41.12	74.63
2017-18	38.94	44.84	1.37	0.73	0.75	47.70	86.64
2018-19	47.32	50.06	2.10	0.09	1.26	53.52	100.84

Note1: The volume of electricity transacted through traders in 2008-09 (April to July 2008) includes cross border trading and intra-state trading volume.

Figure-8: Volume of Electricity Transacted through Traders and Power Exchanges



A comparison between the volume of electricity transacted through traders and power exchanges has been shown in Figure-8. It is observed from the figure that the volume of electricity transacted through traders was relatively high when compared with the volume of electricity transacted through power exchanges during 2008-09 to 2015-16. During the latest three years, i.e. in 2016-17 and 2018-19, the volume of electricity transacted through power exchanges was relatively high when compared with the volume of electricity transacted through traders. This shows that there was more demand for electricity through DAM of power exchanges than the bilateral transactions through traders. The volume of electricity transacted through power exchanges increased at an annual growth rate of 34% whereas the volume of electricity transacted through traders grew at 8% during 2009-10 to 2018-19.

Table-11: Electricity Transacted through Traders and Power Exchanges as percentage of Total Short-term Transactions

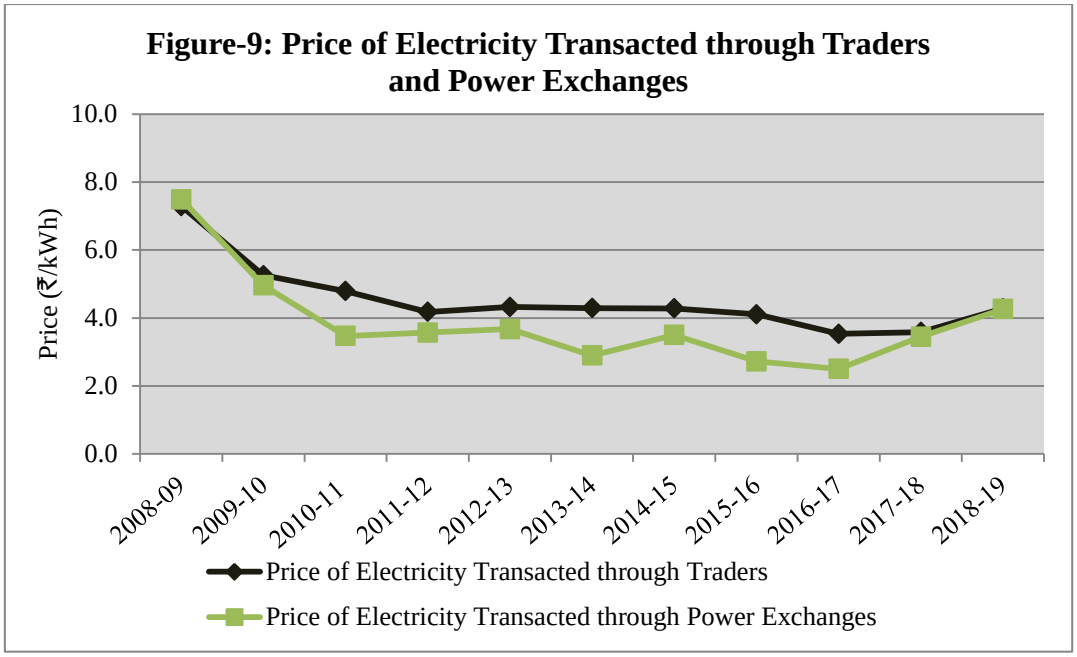
Year	Volume of Electricity Transacted through Traders & Power Exchanges (BUs)	Total Short-term Transactions of Electricity (BUs)	Electricity Transacted through traders & PXs as % to Total Volume of Short-term
2009-10	33.91	65.90	51.45%
2010-11	43.22	81.56	53.00%
2011-12	51.38	94.51	54.37%
2012-13	59.66	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%

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 ₹4.28/kWh and ₹4.26/kWh respectively in 2018-19. Except in 2008-09, the price of electricity transacted through traders was relatively high when compared with the price of electricity transacted through power exchanges. This could be for various reasons, mainly 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. 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. Therefore, the nature and duration of contract influence the price of power.

Table-12: Price of Electricity Transacted through Traders and Power Exchanges

Year	Price of Electricity transacted through Traders (₹/kWh)	Price of Electricity transacted through Power Exchanges (DAM+TAM) (₹/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



The size of the bilateral and power exchange market increased from ₹17,617 Crore in 2009-10 to ₹43,064 Crore in 2018-19 and the size of this market increased at an annual growth rate of 10% (Table-13). Variation in volume and price affected the size of bilateral and power exchange market. During 2009-10 to 2018-19, the volume of electricity transacted through bilateral and power exchange registered a positive growth of 7% and 25% respectively, while the price of electricity transacted through both bilateral and power exchange registered a negative growth of 5%. During 2018-19, due to increase in volume and price, the size of bilateral and power exchange market increased by 42% over the previous year.

Table-13: Size of Short-term Power Market (Bilateral and Power Exchange)

Year	Electricity Transacted through trading Licensees (BU)	Price of Electricity Transacted through Trading licensees (₹/kWh)	Size of bilateral trader Market in ₹ Crore	Electricity Transacted through Power Exchanges (BU)	Price of Electricity Transacted through Power Exchanges (₹/kWh)	Size of Power Exchange Market in ₹ Crore	Total Size of the bilateral trader + Power Exchange Market (₹ Crore)
2009-10	26.72	5.26	14055	7.19	4.96	3563	17617
2010-11	27.7	4.79	13268	15.52	3.47	5389	18657
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

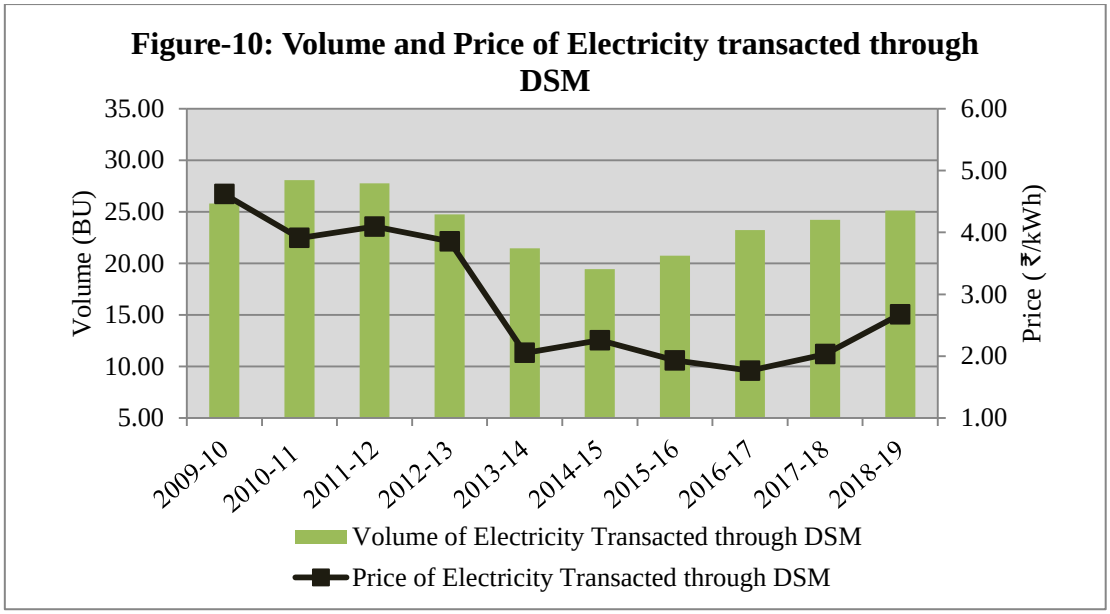
2015-16	35.43	4.11	14557	35.01	2.72	9539	24096
2016-17	33.51	3.53	11844	41.12	2.50	10280	22124
2017-18	38.94	3.59	13970	47.70	3.45	16457	30427
2018-19	47.32	4.28	20255	53.52	4.26	22809	43064

2.1.2 Electricity Transacted through DSM

The volume and price of electricity transacted through DSM is shown in Table-14 and Figure-10. It can be observed from the table that there was a declining trend in the volume of electricity transacted through DSM from 2010-11 to 2014-15 and there was an increasing trend from 2014-15 to 2018-19. However, the volume of DSM as percentage of total short-term volume declined to 17% in 2018-19 from 39% in 2009-10. It can also be observed from the table that the average price of DSM declined from ₹4.62/kWh in 2009-10 to ₹2.68/kWh in 2018-19. This was mainly due to changes in DSM regulations issued by CERC from time to time. Since the DSM is not a market mechanism, the decline in DSM volume is good for the market. As far as the electricity market is concerned, the volume in this segment of the short-term should be as minimal as possible. Price of DSM plays an important role in ensuring system balance and secure reliable grid operation.

Table-14: Volume and Price of Electricity transacted through DSM

Year	Volume of Electricity Transacted through DSM (BU)	Total Volume of Short term (BU)	Volume of DSM as % of total volume of Short term	Price of Electricity Transacted through DSM (₹/kWh)
2009-10	25.81	65.90	39%	4.62
2010-11	28.08	81.56	34%	3.91
2011-12	27.76	94.51	29%	4.09
2012-13	24.76	98.94	25%	3.86
2013-14	21.47	104.64	21%	2.05
2014-15	19.45	98.99	20%	2.26
2015-16	20.75	115.23	18%	1.93
2016-17	23.22	119.23	19%	1.76
2017-18	24.21	127.62	19%	2.03
2018-19	25.13	145.20	17%	2.68



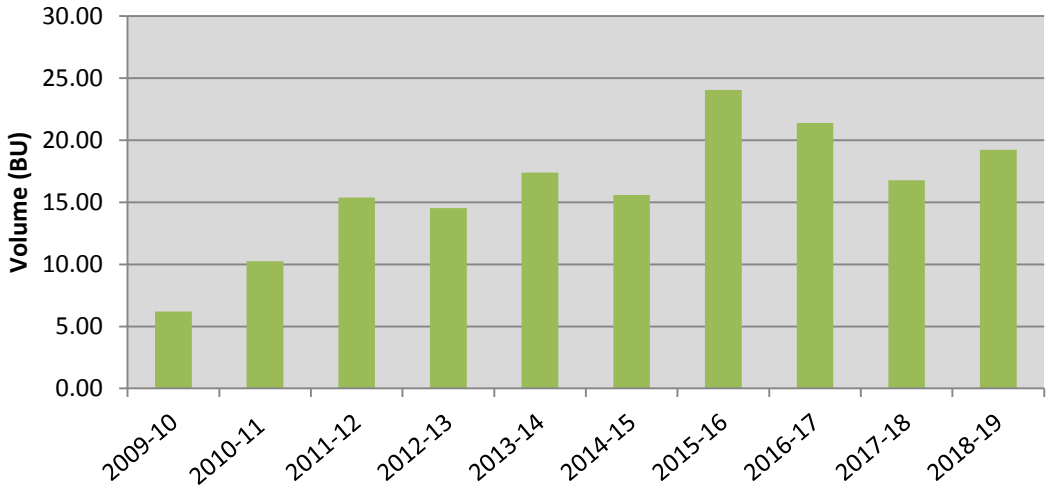
2.1.3 Electricity Transacted Directly Between DISCOMs

The volume of electricity transacted directly between DISCOMs is shown in Table-15 and Figure-11. It can be observed from the table that the volume of electricity transacted directly between DISCOMs increased from 6.19 BU in 2009-10 to 19.23 BU in 2018-19. It can also be observed that there was a declining trend in the share of volume of electricity transacted directly between DISCOMs in total volume of short-term transactions of electricity during 2015-16 to 2018-19.

Table-15: Volume of Electricity Transacted Directly between DISCOMs

Year	Volume of Electricity Transacted Directly between DISCOMs (BU)	Total Volume of Short term (BU)	Volume of Bilateral Direct as % of total volume of Short term
2009-10	6.19	65.9	9%
2010-11	10.25	81.56	13%
2011-12	15.37	94.51	16%
2012-13	14.52	98.94	15%
2013-14	17.38	104.64	15%
2014-15	15.58	98.99	16%
2015-16	24.04	115.23	21%
2016-17	21.38	119.23	18%
2017-18	16.77	127.62	13%
2018-19	19.23	145.20	13%

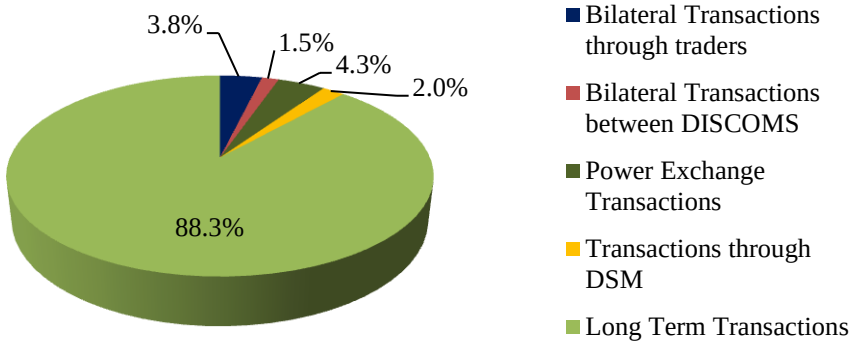
Figure-11: Volume of Electricity Transacted Directly between DISCOMs



3. Monthly Trends in Short-term Transactions of Electricity (April 2018-March 2019)

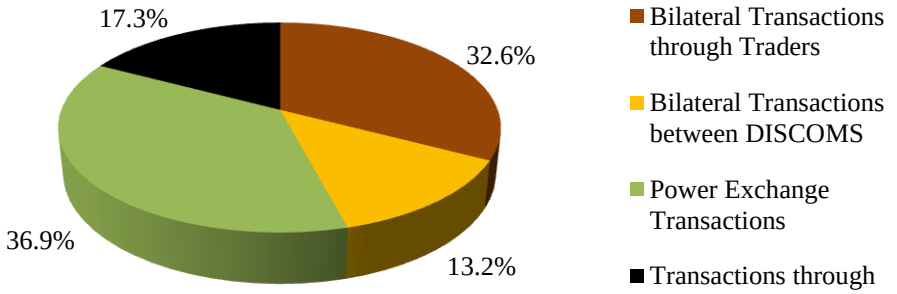
During 2018-19, the share of total short-term transactions in volume terms, including DSM, as a percentage of total electricity generation in the country was about 12% (Figure-12 and Table-16).

Figure-12: Share of Market Segments in Total Electricity Generation, 2018-19



The share of different market segments within the total short-term transaction for the year 2018-19 has been shown in the Figure-13 below.

Figure-13: Share of Market Segments in Short Term Transactions, 2018-19



3.1 Volume of Short-term Transactions of Electricity

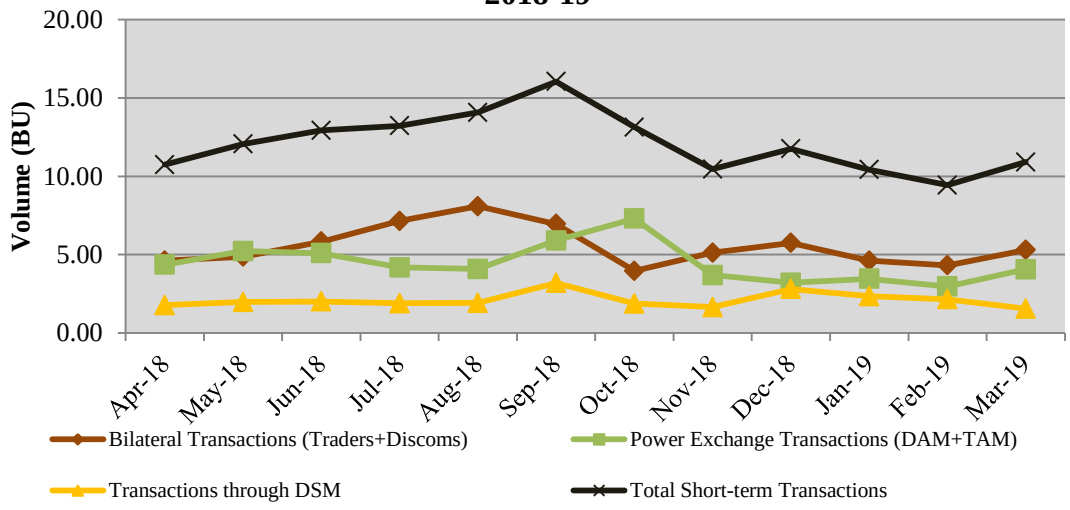
The volume of short-term transactions of electricity during different months of 2018-19 with break-up for different segments is shown in Table-16 and Figure-14.

Table-16: Volume of Short-term Transactions of Electricity (BU), 2018-19

Period	Bilateral through Traders	Bilateral between DISCOMS	Total Bilateral transac-tions	Power Exchange transac-tions (DAM+TAM)	Transac-tions through DSM	Total Short-term transac-tions	Total Electricity Generation
Apr-18	2.60	2.01	4.61	4.36	1.77	10.74	103.46
May-18	3.37	1.49	4.86	5.22	1.97	12.06	110.61
Jun-18	4.64	1.19	5.83	5.09	2.01	12.93	103.00
Jul-18	5.68	1.47	7.15	4.19	1.89	13.23	102.42
Aug-18	6.66	1.43	8.08	4.08	1.91	14.08	105.67
Sep-18	5.38	1.57	6.95	5.90	3.19	16.04	108.05
Oct-18	2.10	1.85	3.96	7.30	1.88	13.13	113.37
Nov-18	3.03	2.09	5.12	3.69	1.65	10.46	99.89
Dec-18	4.26	1.49	5.75	3.20	2.80	11.75	100.54
Jan-19	3.23	1.39	4.62	3.46	2.35	10.43	100.36
Feb-19	2.83	1.49	4.32	2.97	2.15	9.44	91.21
Mar-19	3.53	1.77	5.30	4.06	1.55	10.91	106.76
Total	**47.32**	**19.23**	**66.55**	**53.52**	**25.13**	**145.20**	**1245.32**

It is observed from Figure-14 that there is a cyclical trend in the monthly volume of short-term transactions of electricity. A similar trend is also observed in the volume of bilateral transations. It is also observed from the figure that the volume of all other segments of the short-term transactions of electricity reflect irregular trend.

Figure-14: Volume of Short-term Transactions of Electricity, 2018-19



The volume of short-term transactions of electricity as percentage of total electricity generation varied between 10.22% and 14.85% during the months from April 2018 to March 2019 (Table-17).

Table-17: Volume of Short-term Transactions of Electricity as % of Total Electricity Generation, 2018-19

Period	Short-term Transactions as % of Total Electricity Generation
Apr-18	10.39%
May-18	10.90%
Jun-18	12.55%
Jul-18	12.92%
Aug-18	13.32%
Sep-18	14.85%
Oct-18	11.59%
Nov-18	10.47%
Dec-18	11.69%
Jan-19	10.39%
Feb-19	10.35%
Mar-19	10.22%

There were 37 inter-state trading licensees as on 31.3.2019. Of the total, 25 trading licensees actively undertook trading during the year 2018-19 (Table-18).

The volume of electricity transacted through traders (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, whereas decrease indicates the opposite. HHI value below 0.15 indicates unconcentration 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 2018-19 was 0.1864, which indicates moderate concentration of market power among the traders.

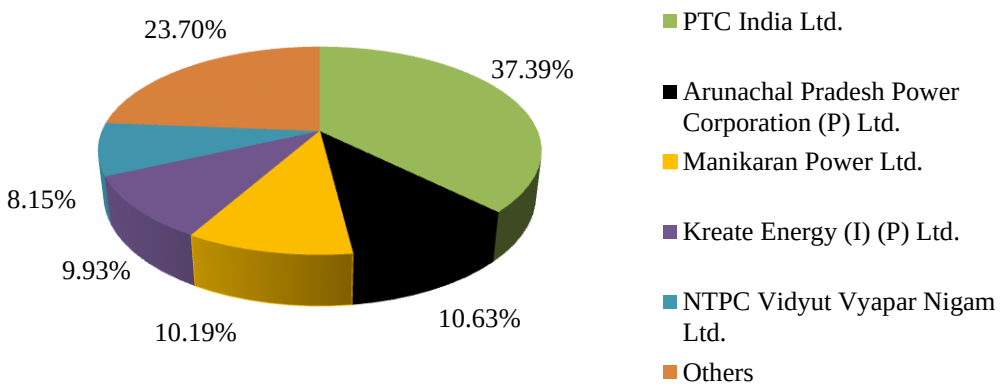
Table-18: Share of Electricity Transacted by Traders and HHI, 2018-19

Sr No	Name of the Trading Licensee	Share of Electricity traded by Licensees in 2018-19	Herfindahl-Hirschman Index (HHI)
1	PTC India Ltd.	37.39%	0.1398
2	Arunachal Pradesh Power Corporation (P) Ltd.	10.63%	0.0113
3	Manikaran Power Ltd.	10.19%	0.0104
4	Kreate Energy (I) (P) Ltd.	9.93%	0.0099
5	NTPC Vidyut Vyapar Nigam Ltd.	8.15%	0.0066
6	Tata Power Trading Company (P) Ltd.	5.46%	0.0030
7	GMR Energy Trading Ltd.	5.39%	0.0029
8	Adani Enterprises Ltd.	3.48%	0.0012
9	JSW Power Trading Company Ltd.	2.19%	0.0005
10	Jaiprakash Associates Ltd.	2.08%	0.0004
11	Knowledge Infrastructure Systems (P) Ltd	1.16%	0.0001
12	Essar Electric Power Development Corp. Ltd.	0.95%	0.0001
13	Statkraft Markets Pvt. Ltd.	0.71%	0.0001
14	RPG Power Trading Company Ltd.	0.59%	0.0000
15	Instinct Infra & Power Ltd.	0.39%	0.0000
16	National Energy Trading & Services Ltd.	0.32%	0.0000
17	Refex Energy Ltd.	0.23%	0.0000
18	IPCL Power Trading (P) Ltd.	0.18%	0.0000
19	Shree Cement Ltd.	0.16%	0.0000

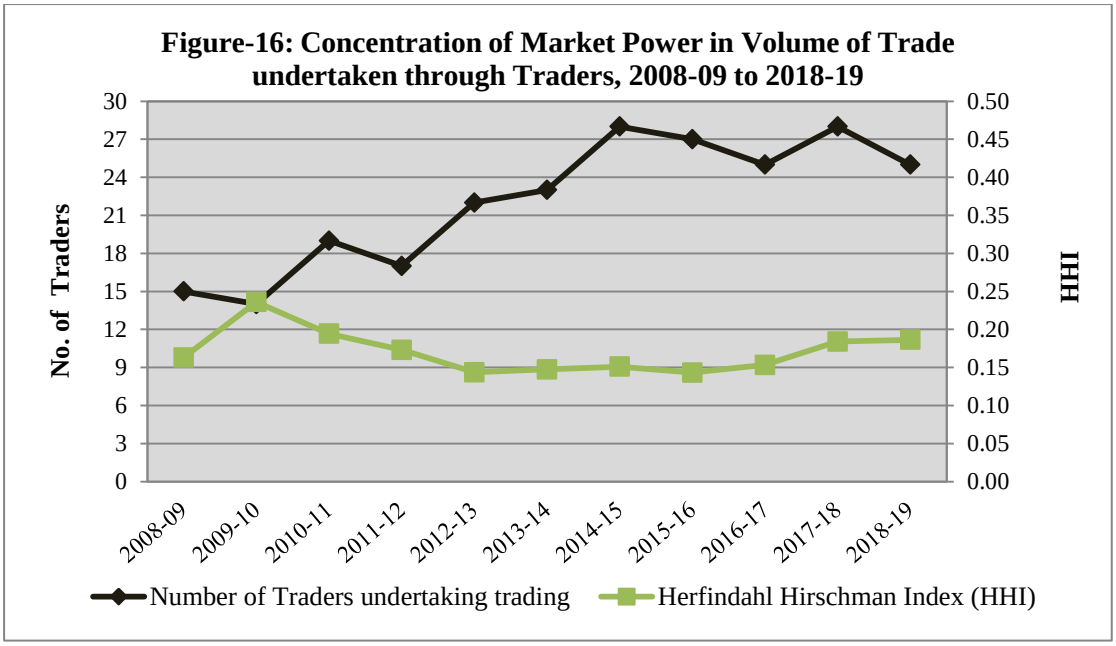
20	Customized Energy Solutions India (P) Ltd.	0.12%	0.0000
21	Abja Power Private Ltd.	0.12%	0.0000
22	Gita Power & Infrastructure (P) Ltd.	0.10%	0.0000
23	NHPC Ltd.	0.04%	0.0000
24	Phillip Commodities India (P) Ltd.	0.01%	0.0000
25	Parshavanath Power Projects Private Ltd.	0.01%	0.0000
Total Volume		100.00%	**0.1864**
Share of the Top 5 Trading		**76.30%**	
Note: Percentage share in total volume traded by Licensees in 2018-19 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, 2018-19



Competition among the traders (HHI based on volume of trade undertaken by the traders) during 2008-09 to 2018-19 is shown in Figure-16. Number of traders, who were undertaking trading bilaterally or through power exchanges or through both, increased from 14 in 2009-10 to 25 in 2018-19. It can be observed from the figure that there is an inverse relationship between the number of traders and the HHI. The concentration of market power declined from HHI of 0.24 in 2009-10 to HHI of 0.19 in 2018-19. The competition among the traders resulted into an increase in volume and decrease in prices in the short-term bilateral market (Table-13).



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 trends in price of electricity transacted through traders (bilateral trader transactions) were studied separately for total transactions as well as for the transactions undertaken during Round the Clock (RTC), Peak and Off-peak periods.

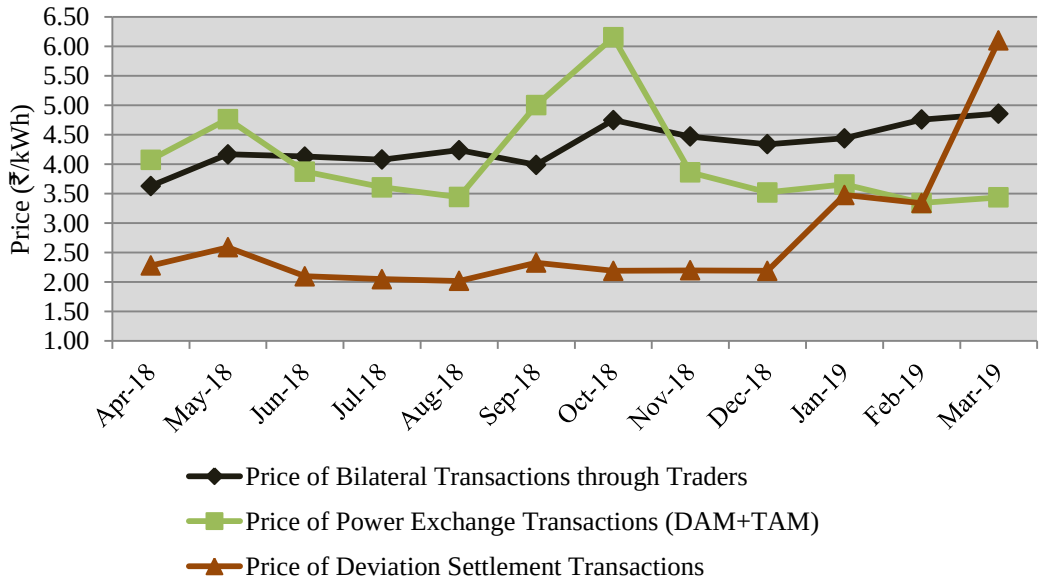
Table-19: Price of Short-term Transactions of Electricity (₹/KWh), 2018-19

Month	Bilateral through Traders				Power Exchange		DSM
	RTC	Peak	Off-peak	Total	IEX	PXIL	All India Grid
Apr-18	4.04	-	4.38	3.63	4.03	3.36	2.28
May-18	4.15	4.28	4.44	4.17	4.76	-	2.59
Jun-18	4.05	4.82	4.48	4.13	3.86	4.70	2.10
Jul-18	4.10	-	3.98	4.08	3.59	3.75	2.05
Aug-18	4.20	4.70	4.82	4.24	3.43	3.14	2.02
Sep-18	3.88	5.41	4.72	3.99	4.99	5.35	2.33
Oct-18	4.83	6.50	4.41	4.75	6.13	6.50	2.19
Nov-18	4.23	8.26	5.08	4.47	3.82	3.38	2.20

Dec-18	4.41	-	3.48	4.34	3.50	4.81	2.19
Jan-19	4.65	6.50	3.79	4.44	3.63	-	3.48
Feb-19	4.74	5.44	5.02	4.76	3.31	3.70	3.34
Mar-19	4.85	5.50	4.93	4.86	3.28	3.72	6.10

(-) No price due to no transactions during the month.

Figure-17: Comparison of Price of Bilateral, Power Exchange and DSM Transactions in 2018-19



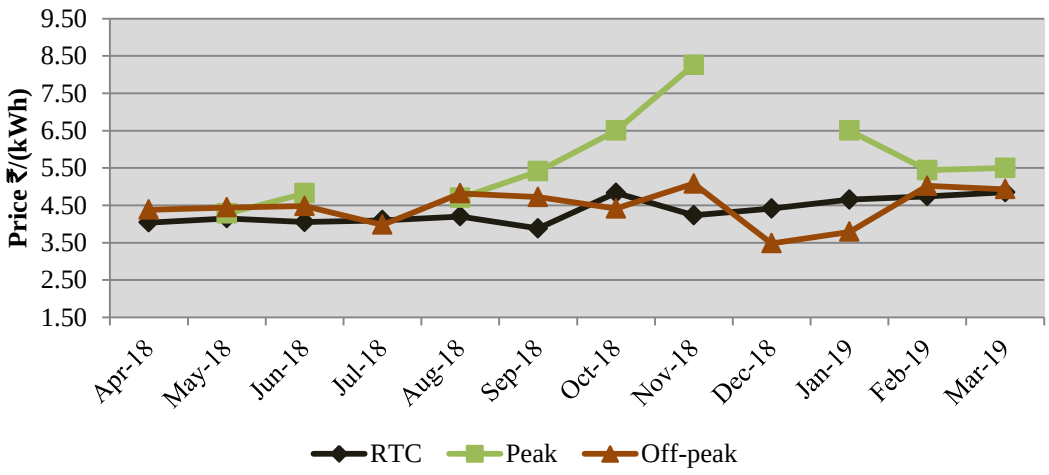
It can be observed from the above figure that the price of electricity transacted through traders was relatively high when compared with the price of electricity transacted through power exchanges in most of the months in 2018-19[6]. The price of electricity transacted through power exchanges was relatively high when compared with the price of electricity transacted through DSM. It is also observed that during April, May, September and October 2018, the price of electricity transacted through power exchanges was relatively high when compared with the price of electricity transacted through traders. Steep increase in price in September and October 2018 was mainly due to high demand for electricity on the power exchanges and low electricity generation (low availability of coal, scanty rainfall and low wind).

[6] *The comparison between the price of power exchanges and the price of bilateral transactions should also be seen in the light that the delivery point for transactions of power exchanges is the periphery of regional transmission system in which the grid connected entity is located whereas the delivery point for bilateral transactions may vary from transaction to transaction. The delivery point may be state or regional periphery or any other point as per the contract executed.*

An increase in the average price of DSM can be observed 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 wth effect from 1st January 2019.

The trends in price of electricity transacted by traders during RTC, Peak and Off-peak periods are shown in Table-19 & Figure-18. It can be observed from the figure that the price of electricity during peak period was higher in all the months in 2018-19 except in May and August 2018 when compared with the price during RTC and off peak periods. There is no price for electricity transacted during peak in April, July and December 2018, which shows that there is no volume of electricity transacted exclusively during peak period in these months.

Figure-18: Price of Electricity Transacted through Traders during Round the Clock, Peak and Off-peak Periods



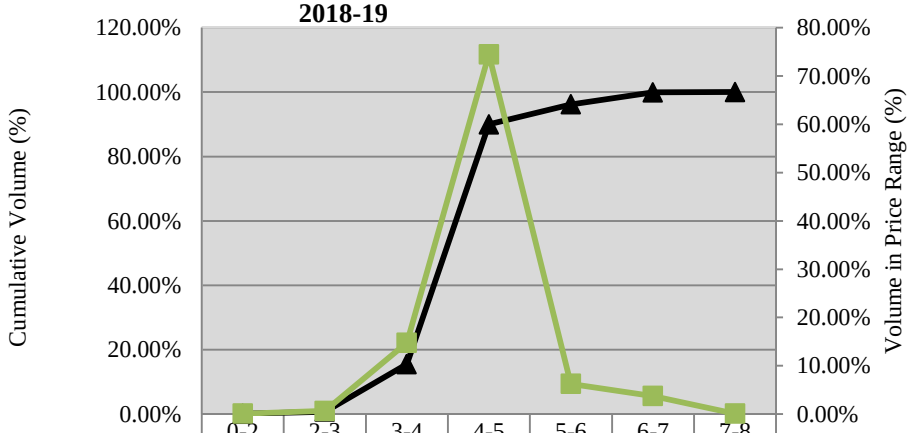
3.3 Volume of Electricity Transacted in Various Price Slabs

Volume of electricity transacted in various price slabs is shown for bilateral trader segment and power exchange segment separately. In the case of power exchanges, Day Ahead Market sub-segment has been considered.

Volume of bilateral transactions at different price slabs in 2018-19 is depicted in Figure-19. The figure shows that 15.5% of the volume of electricity was transacted

through traders at less than ₹4/kWh and 96.2% of the volume was transacted through traders at less than ₹6/kWh.

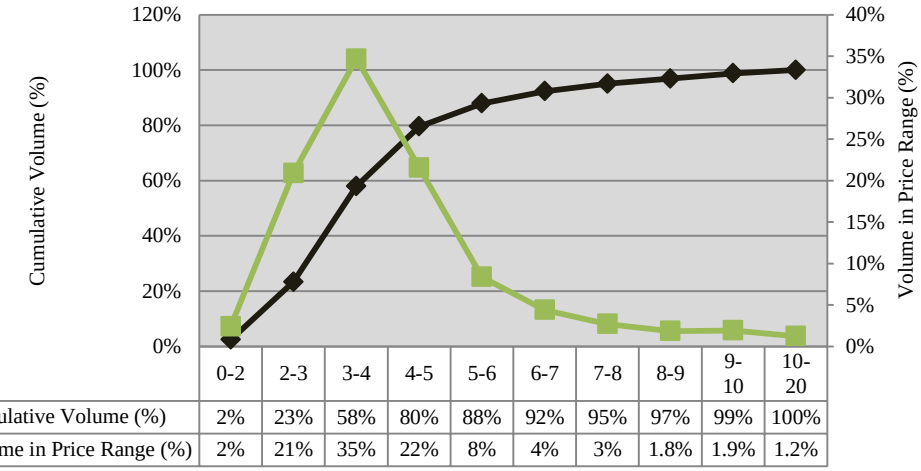
Figure-19: Volume of Bilateral Transactions at different Price Slabs, 2018-19



	0-2	2-3	3-4	4-5	5-6	6-7	7-8
Cumulative Volume (%)	0.07%	0.7%	15.5%	90.0%	96.2%	99.9%	100.00%
Volume in Price Range (%)	0.07%	0.6%	14.8%	74.5%	6.2%	3.7%	0.07%

Volume of IEX transactions at different price slabs in 2018-19 is depicted in Figure-20. The figure shows that 58% of the volume of electricity was transacted through IEX at less than ₹4/kWh and 88% of the volume was transacted through IEX at less than ₹6/kWh.

Figure-20: Volume of IEX Transactions at different Price Slabs, 2018-19

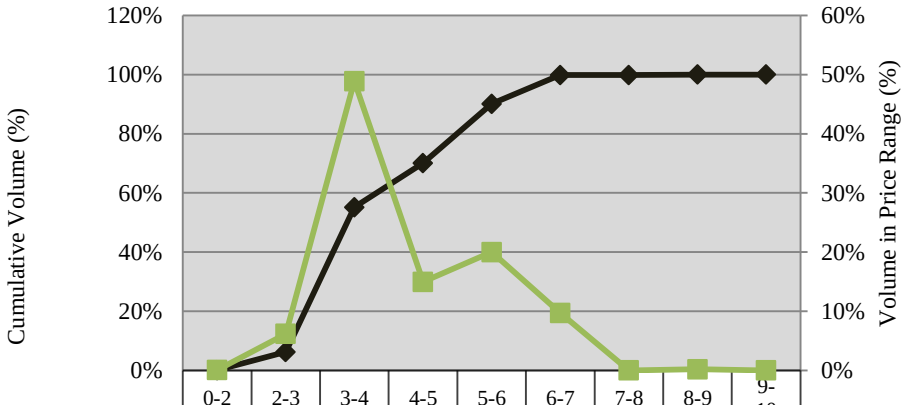


	0-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	10-20
Cumulative Volume (%)	2%	23%	58%	80%	88%	92%	95%	97%	99%	100%
Volume in Price Range (%)	2%	21%	35%	22%	8%	4%	3%	1.8%	1.9%	1.2%

Volume of PXIL transactions at different price slabs in 2018-19 is depicted in Figure-21. The figure shows that 55% of the volume of electricity was transacted

through PXIL at less than ₹4/kWh and 90% of the volume was transacted through PXIL at less than ₹6/kWh.

Figure-21: Volume of PXIL Transactions at different Price Slabs, 2018-19



	0-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10
Cumulative Volume (%)	0%	6%	55%	70%	90%	100%	100%	100%	100%
Volume in Price Range (%)	0%	6%	49%	15%	20%	10%	0%	0%	0%

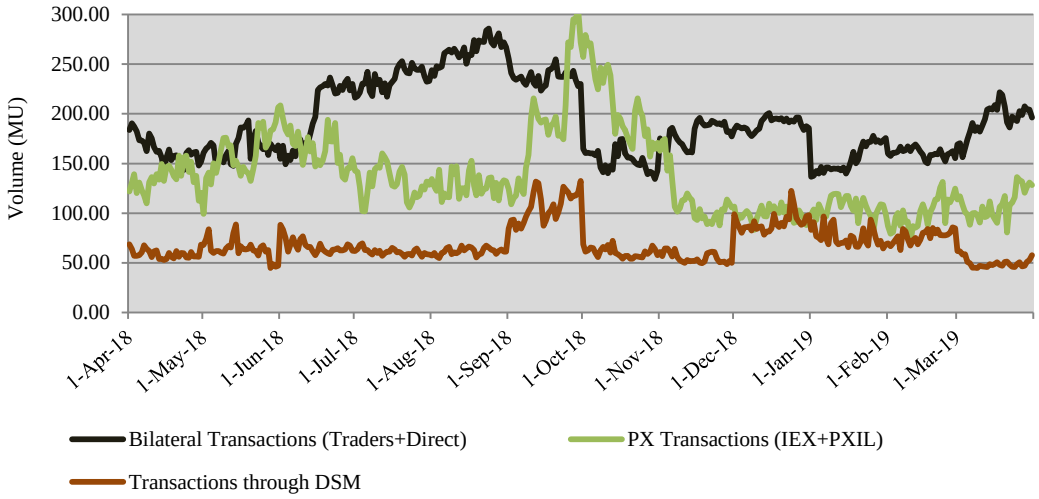
4. Daily Trends in Short-term Transactions of Electricity (1st April 2018 to 31st March 2019)

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 there was a cyclical trend in the volume of electricity transacted through bilateral transactions during 2018-19. It can also be observed that there was irregular trend in the volume of electricity transacted through power exchanges during the year. The trend in volume of electricity transacted through DSM was was almost constant between April to September 2018.

In addition to observing the trends in price of electricity transacted through traders, power exchanges and DSM, volatility in the price of electricity transacted through power exchanges and DSM has been provided in Figure-23, 24 & 25.

Figure-22: Volume of Short-term Transactions of Electricity, 2018-19



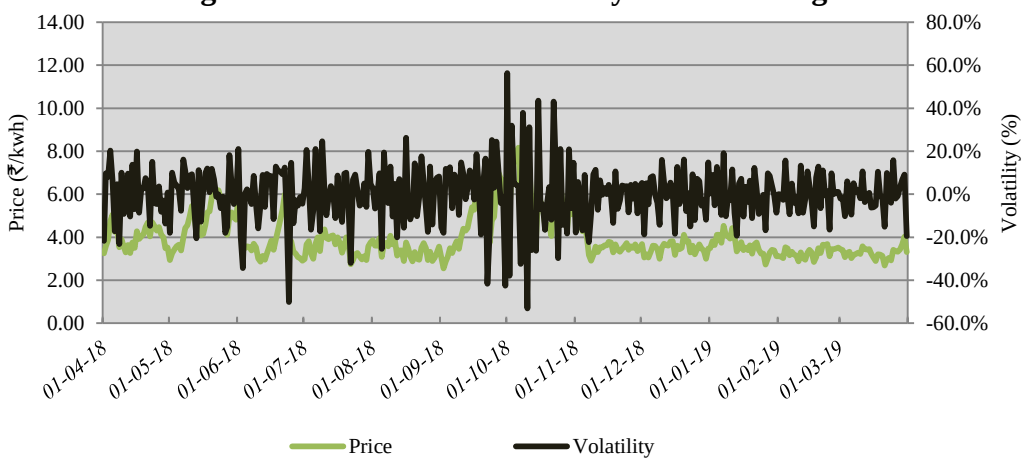
4.2 Price of Short-term Transactions of Electricity

Trends in daily price of short-term transactions have been illustrated in this section for power exchanges and DSM.

4.2.1 Price and its volatility in Power Exchanges

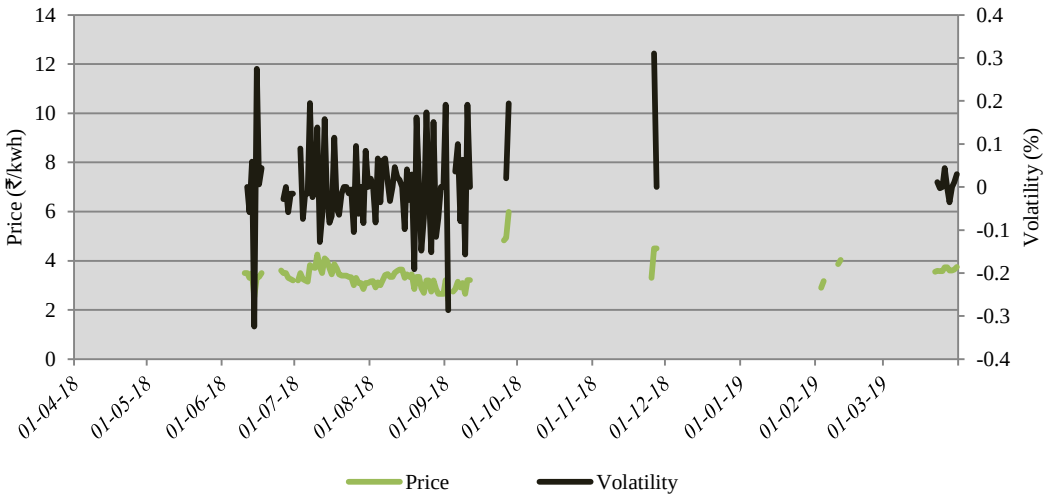
The weighted average price of electricity transacted through IEX and its volatility is shown in Figure-23. Volatility in the Price of electricity transacted through IEX has been computed using daily data for 2018-19 and it works out to 13.14%. (See Annexure-III for historic volatility formula).

Figure-23: Price and its Volatility in IEX during 2018-19



The weighted average price of electricity transacted through PXIL and its volatility is shown in Figure-24. Volatility in the price of electricity transacted through PXIL has been computed using daily data for 2018-19 and it works out to 10.02%.

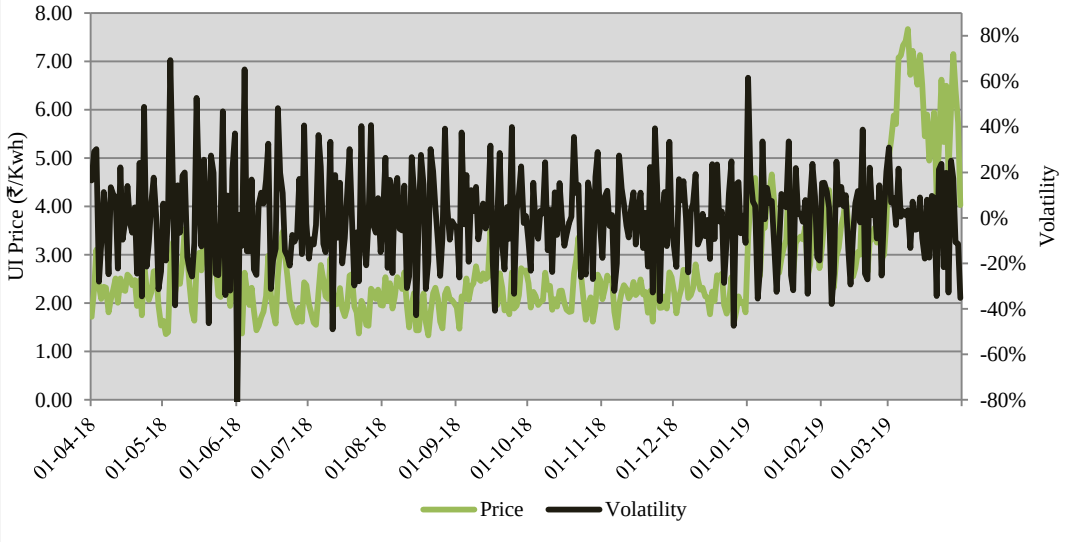
Figure-24: Price and its Volatility in PXIL during 2018-19



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 2018-19 and it works out to 20.89%.

Figure-25: Price and its Volatility in DSM during 2018-19



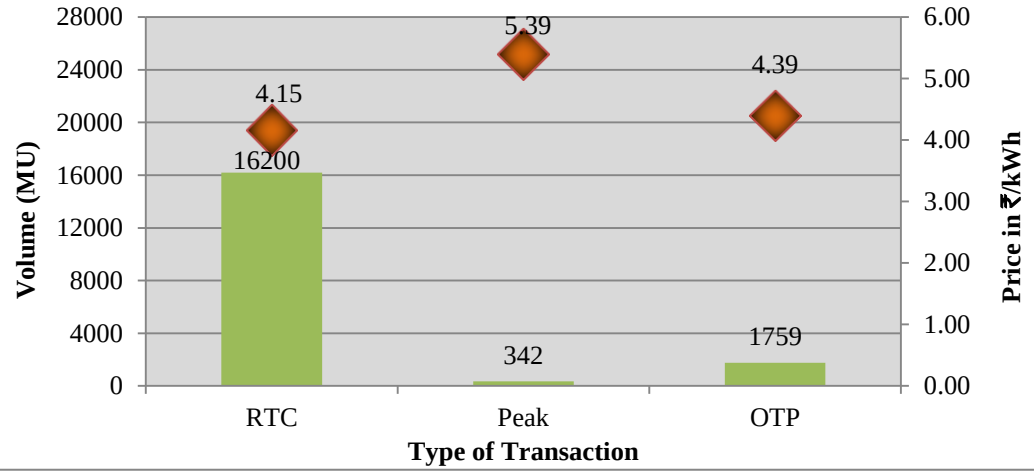
5. Time of the Day Variation in Volume and Price of Electricity Transacted through Traders and Power Exchanges

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 also shown 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 2018-19 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, 88.5% was transacted during RTC followed by 9.6% during OTP, and 1.9% during peak period. It can be observed from the figure that there is hardly any volume transacted during peak period. It can also be observed that the weighted average price during Peak period is high (₹5.39/kWh), when compared with the price during RTC (₹4.15/kWh) and OTP (₹4.39/kWh).

Figure-26: Volume and Price of Electricity Transacted through Traders during RTC, Peak and OTP, 2018-19



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 through IEX and PXIL (Day ahead market) during 2018-19 are shown block-wise in Figure-27 and Figure-28. It can be observed from the figure that the weighted average price in both the power exchanges was higher during peak period (between hours 18:00 to 23:00), when compared to the weighted average price in rest of the hours.

Figure-27: Block-wise Market Clearing Volume and Price in IEX during 2018-19

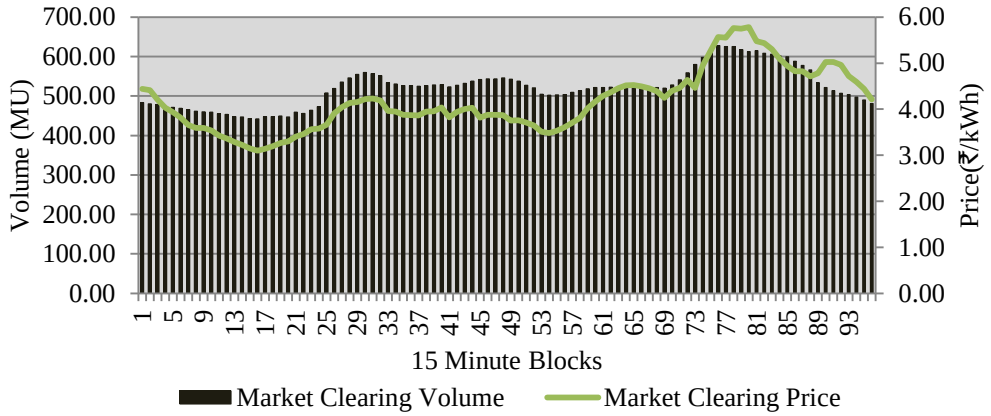
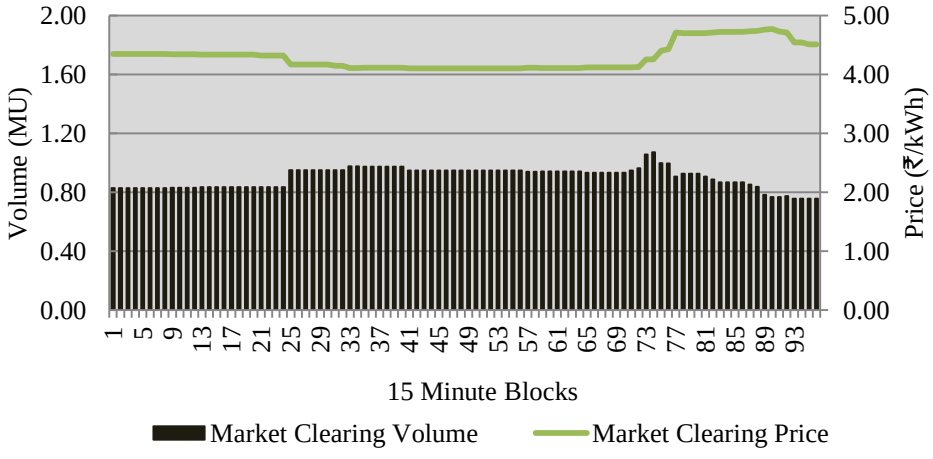


Figure-28: Block-wise Market Clearing Volume and Price in PXIL during 2018-19



Region-wise and hour-wise prices of electricity transacted through power exchanges are shown in Figure-29 and Figure-30. It can be observed from the figures

that during 2018-19, the price of electricity in Southern region (S1, S2 and S3 regions) was marginally high when compared with the price in other regions in IEX. This is mainly due to high demand for electricity in the southern region. The prices were high due to congestion between southern region and rest of the regions, accompanied by market splitting on the power exchanges.

Figure-29: Region-wise and Block-wise Price of Electricity Transacted through IEX, 2018-19

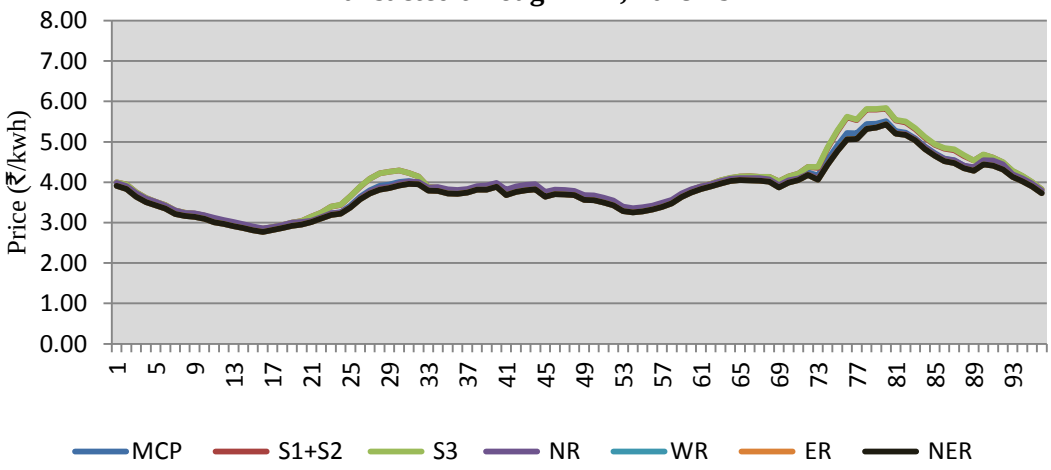
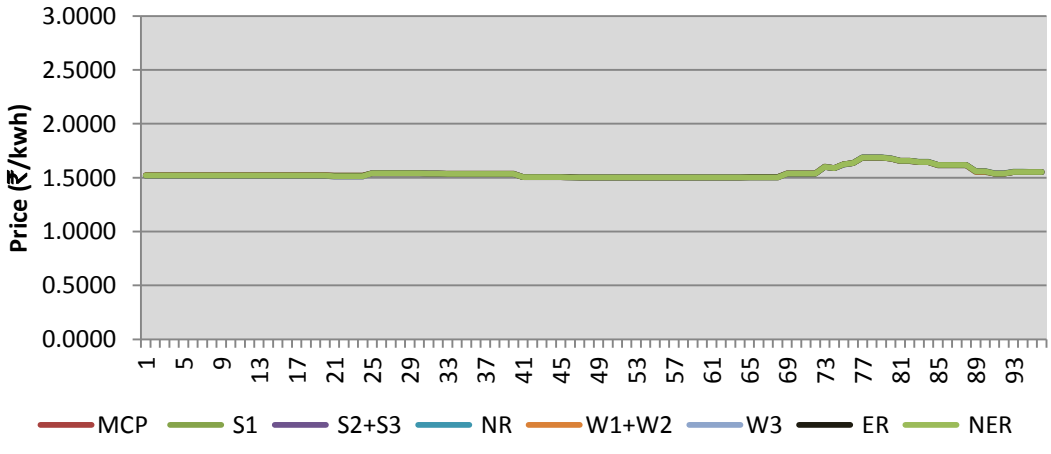


Figure-30: Region-wise and Block-wise Price of Electricity Transacted through PXIL, 2018-19



6. Trading Margin Charged by Trading Licensees

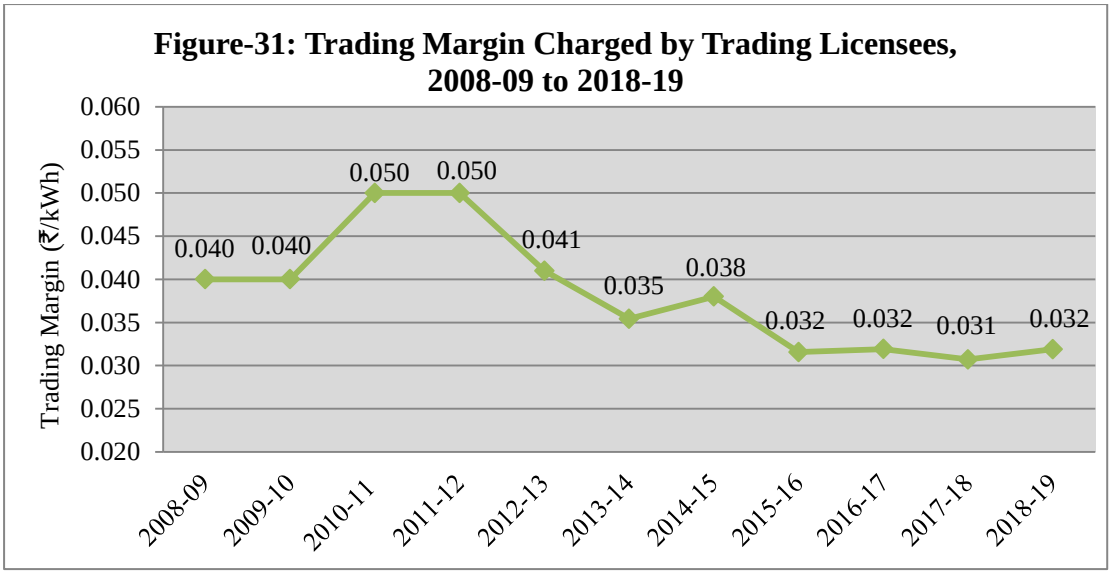
During the year 2004-05 (when trading started through licensees), the licensees voluntarily charged 5 paise/kWh or less as the trading margin for bilateral

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 26.1.2006. As a result of these trading margin regulations, the licensees charged trading margin of 4 paise or less from 26.1.2006 onwards until revised Trading Margin Regulations, 2010 came into existence on 11.1.2010 (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. 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 weighted average trading margin charged by the trading licensees for bilateral transactions during 2008-09 to 2018-19 is provided in Table-20 and Figure-31.

Table -20: Trading Margin Charged by Trading Licensees, 2008-09 to 2018-19

Period	Trading Margin (₹/kWh)
2008-09	0.040
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
Note 1: Weighted Average Trading Margin is computed based on all Inter-state Trading Transactions excluding Banking Transactions	



Weighted average trading margin charged by the trading licensees for bilateral transactions for different sale prices (as specified in the trading margin regulations) during 2018-19 is provided in Table-21 below.

Table-21: Trading Margin Charged by Trading Licensees, 2018-19

Sale Price of Electricity Transacted by Trading Licensees(₹/kWh)	Weighted Average Trading Margin Charged by Trading Licensees (₹/kWh)
When Sale Price is less than or Equal to ₹3/kWh	0.025
When Sale Price is greater than ₹3/kWh	0.032

Note 1: Weighted Average Trading Margin is computed based on volume and margin of all Inter-state Trading Transactions excluding Banking Transactions.

7. Open Access Consumers on Power Exchanges

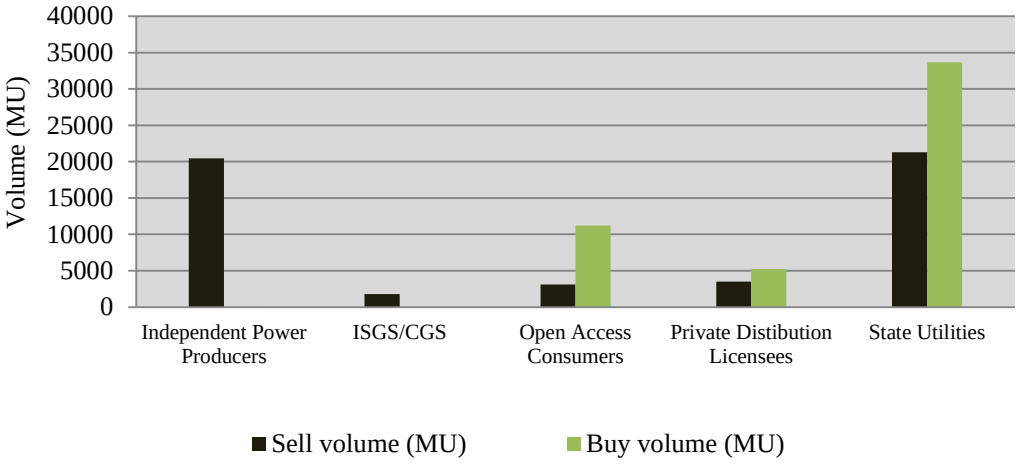
This section contains analysis of various types of participants and analysis of open access consumers in day ahead market of power exchanges.

7.1 Types of Participants in Power Exchanges

There are five types of participants in IEX, as shown in Figure-32. It can be observed from the figure that major sellers of electricity through IEX were independent power producers and state utilities. It can also be observed that major

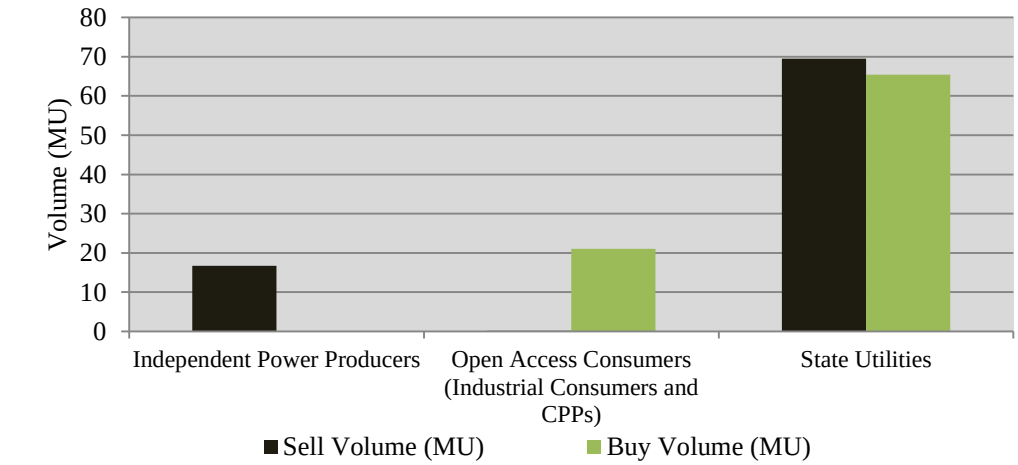
buyers of electricity through IEX were state utilities followed by open access consumers, and private distribution licensees.

Figure-32: Sell and Buy Volume of Various Types of Participants in IEX, 2018-19



There are 3 types of participants in PXIL, as shown in Figure-33. It can be observed from the figure that major sellers of electricity through PXIL were state utilities and Independent Power Producers and major buyers of electricity through PXIL were state utilities and industrial consumers.

Figure-33: Sell and Buy Volume of Various Types of Participants in PXIL, 2018-19



7.2 Analysis of Open Access Consumers on Power Exchanges

The year 2010-11 witnessed collective open access transactions, 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 4362 and 588 respectively in 2018-19 (Table-22). 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 89% in PXIL. The number of OA consumers in IEX increased at an annual growth of 23%, whereas it was 17% in 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 from 89% in 2012-13 to 16% in 2018-19.

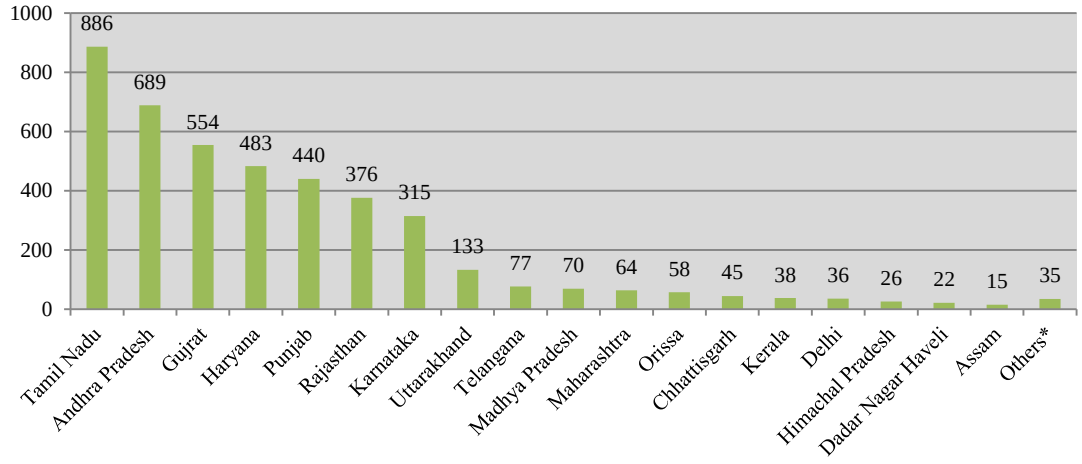
Table-22: Number of Open Access Consumers in Power Exchanges, 2010-11 to 2018-19

Year	IEX			PXIL		
	No. of Open Access Consu-mers	Total No. of Portfolios	% of Open Access Consu-mers	No. of Open Access Consu-mers	Total No. of Portfolios	% of Open Access Consu-mers
2010-11	825	863	96%	170	190	89%
2011-12	968	1073	90%	231	465	50%
2012-13	2110	2227	95%	336	379	89%
2013-14	2958	3083	96%	473	1399	34%
2014-15	3269	3407	96%	517	1779	29%
2015-16	3650	3796	96%	527	2924	18%
2016-17	4071	4281	95%	542	3277	17%
2017-18	4248	4502	94%	559	3422	16%
2018-19	4362	4633	94%	588	3657	16%

In 2018-19, about 4362 OA consumers procured 11219 MU of electricity (a part of their power requirements) through IEX. These OA consumers were mostly located in Tamil Nadu, Andhra Pradesh, Gujarat, Haryana, Punjab, Rajasthan, Karnataka and Uttarakhand (Figure-34). The weighted average price of electricity

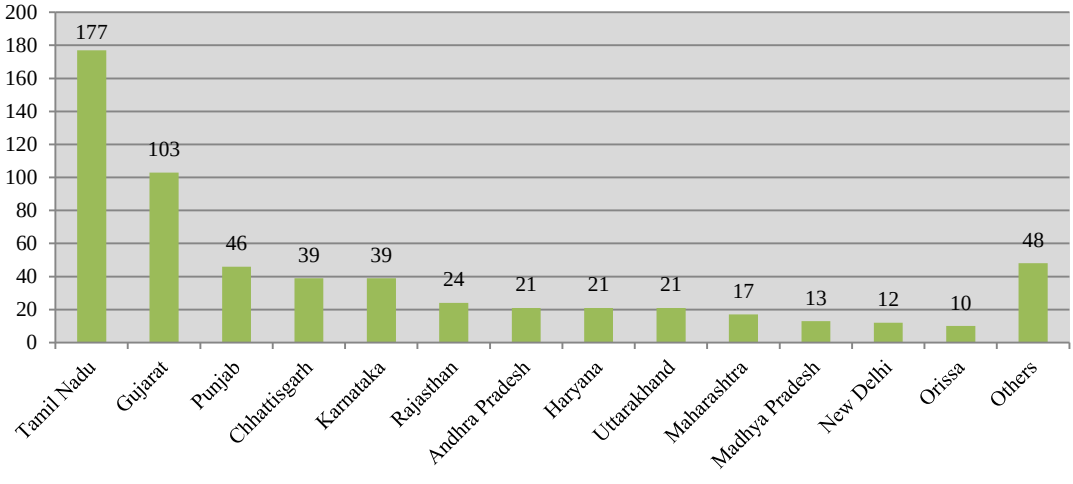
bought by OA consumers at IEX was lower (₹3.48/kWh) when compared to the weighted average price of total electricity transacted through IEX (₹4.22/kWh).

Figure-34: State-wise Number of Open Access Consumers in IEX, March 2019



About 588 OA consumers procured 21 MU of electricity (a part of their power requirements) through PXIL in 2018-19. 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 lower (₹3.27/kWh) when compared to the weighted average price of total electricity transacted through PXIL (₹4.29/kWh).

Figure-35: State-wise Number of Open Access Consumers in PXIL, March 2019



Annual comparison between purchase volume of OA consumers and total volume in both IEX and PXIL during 2010-11 to 2018-19 is shown in Table-23. The volume of electricity procured by OA consumers as a percentage of total volume transacted in IEX varied between 22% and 61% in IEX. The volume of electricity procured by OA consumers as a percentage of total volume transacted in PXIL varied between 1% and 58%.

Table-23: Volume of Purchase by Open Access Consumers in Day Ahead Market of Power Exchanges, 2010-11 to 2018-19

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
2010-11	4057	11801	34%	93	1740	5%
2011-12	6275	13799	45%	307	2058	15%
2012-13	10410	22375	47%	263	688	38%
2013-14	17575	28925	61%	503	1106	45%
2014-15	12084	28141	43%	103	341	30%
2015-16	20284	34067	60%	79	137	58%
2016-17	24000	39831	60%	44	249	18%
2017-18	14728	44925	33%	6	730	1%
2018-19	11219	50136	22%	21	86	24%

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

Table-24 and Table-25 show top 10 sellers and buyers of electricity through traders (bilateral trader segment transactions). The same data for IEX is shown in Table-26 and Table-27, and for PXIL in Table-28 and Table-29. It can be seen that 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. 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 is also provided in the tables.

Table-24: Major Sellers of Electricity through Traders, 2018-19

S.No.	Seller	State	Volume (MU)	Approximate Percentage of total volume transacted through Traders	Weighted Average Sale Price ₹/kWh
1	Sembcorp Gayatri Power Ltd	Andhra Pradesh	2896.94	15.82%	4.16
2	HPSEB (including GOHP)	Himachal Pradesh	2272.77	12.41%	4.10
3	Jaypee Nigrie STPP	Madhya Pradesh	2044.66	11.16%	4.51
4	APPCC	Andhra Pradesh	1228.76	6.71%	4.73
5	Damodar Valley Corporation	West Bengal	1122.95	6.13%	4.14
6	Baglihar HEP Stage-II	Jammu Kashmir	924.43	5.05%	4.13
7	Sembcorp Gayatri Power Ltd	Telangana	923.50	5.04%	4.08
8	Adani Power Ltd	Gujarat	654.82	3.58%	4.86
9	Jindal Power Ltd	Chhattisgarh	606.88	3.31%	4.58
10	DB Power Ltd	Chhattisgarh	528.04	2.88%	4.45
Note : Volume sold by major sellers and total volume transacted through traders does not include the volume through banking arrangements.					

Table-25: Major Buyers of Electricity through Traders, 2018-19

S.No.	Buyer	State	Volume (MU)	Approximate percentage of total volume transacted through traders	Weighted Avearage Purchase Price (₹/kWh)
1	Uttar Pradesh Power Corporation Ltd	Uttar Pradesh	5821.95	31.79%	4.08
2	Nepal Electricity Authority	Nepal	2241.56	12.24%	3.68
3	Telangana State Power Coordination Committee	Telangana	1385.20	7.56%	5.01
4	Gujarat Urja Vikas Nigam Ltd	Gujarat	998.59	5.45%	3.86

5	Uttrakhand Power Corporation Ltd	Uttarakhand	850.30	4.64%	3.98
6	MSEDCL	Maharashtra	844.09	4.61%	4.28
7	Bihar State Power Holding Company Ltd	Bihar	801.78	4.38%	5.11
8	Punjab State Power Corporation Ltd	Punjab	737.32	4.03%	4.14
9	Tamil Nadu Generation and Distribution Corporation Ltd	Tamil Nadu	698.92	3.82%	4.70
10	Haryana Power Purchase Center	Haryana	647.86	3.54%	4.43
Note : Volume Bought by major buyers and total volume transacted through traders does not include the volume through banking arrangements.					

From Table-25, it can be seen that the weighted average purchase prices of electricity of major buyers such as TSPCC, BSPHCL, TANGEDCO and Haryana power purchase centre from traders (bilateral transactions) were higher than the weighted average price for the entire bilateral trader segment (₹4.28/kWh).

Table-26: Major Sellers of Electricity in Day Ahead Market of IEX, 2018-19

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	Teesta Urja Ltd	Teesta Urja Ltd	3313.69	6.61%	4.20
2	MPPMCL	Madhya Pradesh	3182.15	6.35%	3.52
3	Sembcorp Energy India Ltd	Andhra Pradesh	2388.51	4.76%	4.10
4	JVVNL	Rajasthan	2339.65	4.67%	4.18
5	APCPDCL	Telangana	2167.61	4.32%	3.49
6	PSPCL	Punjab	1778.29	3.55%	5.60
7	DVC	DVC	1395.22	2.78%	3.53
8	DB Power Ltd	DB Power Ltd	1373.65	2.74%	4.75
9	BYPL	Delhi	1237.65	2.47%	4.06
10	GOHP	Himachal Pradesh	1100.32	2.19%	4.31
Note: Total Volume transacted through Day Ahead Market in IEX was about 50136.00 MU.					

Table-27: Major Buyers of Electricity in Day Ahead Market of IEX, 2018-19

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	6361.12	12.69%	4.41
2	BSPHCL	Bihar	4554.16	9.08%	4.47
3	APCPDCL	Telangana	3565.06	7.11%	4.74
4	MSEDCL	Maharashtra	3465.98	6.91%	4.96
5	WBSEDCL	West Bengal	2458.97	4.90%	4.56
6	J & K PDD	J&K	2423.80	4.83%	4.20
7	Vedanta Ltd	Orissa	2147.82	4.28%	4.35
8	Adani Electricity Mumbai Ltd	Maharashtra	2068.28	4.13%	4.18
9	TANGEDCO	Tamil Nadu	1959.67	3.91%	5.48
10	Torrent Power Ltd	Gujarat	1383.91	2.76%	4.42
Note: Total Volume transacted through Day Ahead Market in IEX was about 50136.00 MU.					

From Table-27, it can be seen that the weighted average prices of electricity for major buyers such as GUVNL, BSPHCL, APCPDCL, MSEDCL, WBSEDCL, Vedanta Ltd, TANGEDCO and Torrent Power Ltd in the day ahead market of IEX were higher than the weighted average price for the entire day ahead market of IEX (₹4.22/kWh).

Table-28: Major Sellers of Electricity in Day Ahead Market of PXIL, 2018-19

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	DVC	West Bengal	37.53	43.44%	3.98
2	DB Power Ltd	Chhattisgarh	10.29	11.91%	5.46
3	KSEB	Kerala	9.61	11.12%	3.05
4	Haryana Power Purchase Center	Haryana	9.00	10.42%	5.77
5	MPDCL	Meghalaya	6.99	8.09%	3.35
6	MPPTCL	Madhya Pradesh	5.80	6.71%	3.41
7	Jindal Power Ltd	Chhattisgarh	2.40	2.78%	3.30

8	Adani Power Ltd	Gujarat	2.35	2.72%	3.69
9	IL&FS Tamil Nadu Power Company Ltd	Tamil Nadu	1.26	1.46%	4.24
10	Udupi Power Corporation Ltd	Karnataka	0.43	0.50%	3.60
Note: Total Volume transacted in the Day Ahead Market of PXIL was about 86.40 MU.					

From Table-29, it can be seen that the weighted average prices of electricity for major buyers such as GUVNL and TNEB in the PXIL Day Ahead Market were higher than the weighted average price for the entire day ahead market of PXIL (₹4.29/kWh).

Table-29: Major Buyers of Electricity in Day Ahead Market of PXIL, 2018-19

Sr. No	Name of the Buyer	State/Regional Entity	Buy Volume (MU)	Percentage of the Total Volume Transacted	Weighted Average Buy Price (₹/kWh)
1	Gujarat Urja Vikas Nigam Ltd	GUJRAT	34.60	40.05%	5.29
2	Himachal Pradesh State Electricity Board	Himachal Pradesh	19.62	22.71%	3.90
3	Kirloskar Ferrous Industries Ltd	Karnataka	19.00	21.99%	3.28
4	Kerala State Electricity Board	Kerala	7.20	8.33%	3.65
5	DVC	DVC	2.40	2.78%	3.30
6	KIOCL Ltd	Karnataka	1.92	2.22%	3.24
7	Tamil Nadu Electricity Board	Tamil Nadu	1.56	1.81%	4.32
8	Krishna Ganga Spinning Mills (P) Ltd	Andhra Pradesh	0.06	0.07%	3.02
9	IFFCO Plant	Gujarat	0.04	0.04%	2.53
Note: Total Volume transacted in the Day Ahead Market of PXIL was about 86.40 MU.					

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-30 and Table-31.

The effect of congestion on volume of electricity transacted through power exchanges during 2009-10 to 2018-19 is shown in Table-30. 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 8.10BU and 7.09BU respectively in 2009-10 to 50.69BU and 50.22BU respectively in 2018-19. There is an increasing trend in 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 from 2010-11 to 2012-13 and a declining trend from 2012-13 to 2018-19. Congestion in power exchanges has been reduced since grid integration (integration of NEW Grid and SR Grid) in December 2013, leading to 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. In the latest two years i.e. 2017-18 and 2018-19, the volume of electricity that could not be cleared as % to uncontrained cleared volume was less than 1 per cent which shows that the congestion was insignificant.

Table-30: Effect of Congestion on the Volume of Electricicity Transacted through Power Exchanges, 2009-10 to 2018-19

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
1	2	3	4 (2-3)	5 (4/2)
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%
** This power would have been scheduled had there been no congestion.*				

Source: IEX & PXIL

During 2018-19, in IEX, the unconstrained cleared volume and the actual volume transacted were 50.60BU and 50.14BU respectively (Table-31). The actual transacted volume was 0.92% lesser than unconstrained volume. During the same year, in PXIL, the unconstrained cleared volume and the actual volume transacted were 0.089BU and 0.086BU respectively. The actual transacted volume was 3.20% lesser than unconstrained volume.

Table-31: Details of Congestion in Power Exchanges, 2018-19

	Items	IEX	PXIL	Total
A	Unconstrained Cleared Volume* (BU)	50.60	0.089	50.69
B	Actual Cleared Volume and hence scheduled (BU)	50.14	0.086	50.22
C	Volume of electricity that could not be cleared and hence not scheduled because of congestion (BU) (A-B)	0.46	0.003	0.47
D	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume	0.92%	3.20%	0.92%
** This power would have been scheduled had there been no congestion.*				

Source: IEX, PXIL & NLDC

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 2018-19 is provided in Table-32. It can be observed from the table that there is an irregular trend in congestion charges during the period. The congestion charges in 2018-19 was more than double when compared to the previous year.

Table-32: Congestion Charges of Power Exchanges, 2008-09 to 2018-19

Year	Congestion Charges in IEX (₹ Crore)	Congestion Charges in 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

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 time frames 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; (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, increasing private sector participation and competition introduced in 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. 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 per cent of the variable charges are payable by RRAS providers to the pool. No commitment charges are payable to the RRAS provider.

10.3 RRAS Instructions issued by Nodal Agency

During 2018-19, the Nodal Agency has issued 5501 RRAS Up/Down instructions on account of various triggering criteria (Table-33). Of the total, there were 3898 RRAS Up instructions and 1603 RRAS Down instructions. Majority of the Regulation Up instructions were on account of multiple reasons followed by trend of load met while majority of the Regulation Down instructions were on account of multiple reasons followed by trend of load met and high frequency.

Table-33: Number of times RRAS triggered based on Triggering Criteria, 2018-19

Sr No.	Triggering Criteria	Regulation Up (Nos.)	Regulation Down (Nos.)	Total
1	Multiple reasons	1998	1100	3098
2	Trend of load met	1852	216	2068
3	High Frequency	0	277	277

4	One or more transmission lines in the corridor are loaded beyond the normal limit	14	1	15
5	Low Frequency	4	0	4
6	Generating unit or Transmission line outages	4	0	4
7	Extreme weather conditions	0	1	1
8	Others	26	8	34
	Total	**3898**	**1603**	**5501**

Source: POSOCO Website

At times, the dispatch under Ancillary is not attributable to any single triggering criteria, and the operator has to specify "Others" as triggering criteria. There is a need to enhance the number of triggering criteria to provide more clarity and to encompass the dynamic behavior of the power system.

Table-34 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 2018-19 in a time block, maximum power despatched was 3816 MW in July 2018 while the maximum power regulated was 2938 MW in March 2019.

Table-34: Maximum Ancillary Despatched in a Time Block (MW), 2018-19

Month	Max regulation "UP"	Max regulation "DOWN"
Apr-18	2694	1074
May-18	2551	2702
Jun-18	2655	1637
Jul-18	3816	2518
Aug-18	3008	908
Sep-18	3263	2260
Oct-18	2504	468
Nov-18	2775	1197
Dec-18	3285	2246
Jan-19	1690	2638
Feb-19	1437	1862
Mar-19	972	2938

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 2018-19 has been provided in Table-35.

Table-35: Energy Scheduled and Payments made for Ancillary Services, 2016-17 to 2018-19

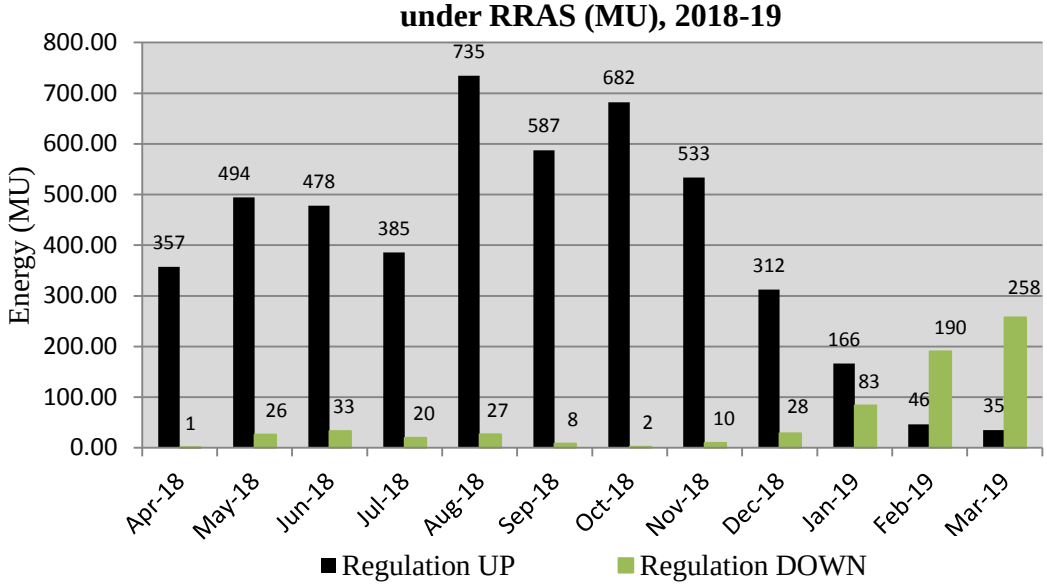
Year	Energy scheduled to/from Virtual Ancillary Entity under RRAS (MU)		Payments made for Ancillary Services (₹Crore)	
	Regulation UP	Regulation DOWN	To RRAS provider(s) from DSM Pool for Regulation UP	By RRAS provider(s) to DSM Pool for Regulation DOWN
2016-17	2212.28	286.00	939.78	42.39
2017-18	4149.25	243.72	2011.47	43.60
2018-19	4811.69	685.42	2810.73	140.83

Source: POSOCO Website

The energy scheduled under Regulation UP of RRAS was increased from 2212.28MU in 2016-17 to 4811.69 MU in 2018-19 and the increase was 117%. However, the energy scheduled under Regulation DOWN of RRAS was also increased from 286.00MU in 2016-17 to 685.42 in 2018-19 and the increase was 140%.

Month-wise energy scheduled to/from VAE under RRAS during 2018-19 can be seen in Figure-36. It can be observed from the figure that ancillary despatch under Regulation UP was relatively high when compared with the ancillary despatch under Regulation DOWN from April 2018 to January 2019 whereas it was reverse from February 2019 to March 2019.

Figure-36: Energy Scheduled to/from Virtual Ancillary Entity under RRAS (MU), 2018-19



Presently, the Ancillary Services implementation is load-following and for congestion management. There are other forms of ancillary services which also need to be considered as we move ahead.

While the RRAS is primarily a framework for slow tertiary reserves, recognizing the need of ancillary services with further shorter time of response, the Commission approved implementation of two pilot projects.

In the first pilot project, i.e. for Secondary frequency response, the Commission, vide order dated 07.12.2017, approved implementation of Automatic Generation Control (AGC) pilot project which have the ability to follow signals, given directly by system operator (POSOCO), to regulate variation in Area Control Error (ACE) by increasing/decreasing generation. The response time is quick and automated. In the second pilot project, i.e. for Fast Response Ancillary Services (FRAS), the Commission, vide order dated 16.07.2018, endorsed implementation of a pilot project on Hydro power stations, which can respond very quickly and comparatively faster than thermal/ gas stations. After gaining experience from these two pilot projects, similar projects may be replicated for better ancillary services.

Chapter-III

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; (e) the promotion of co-generation and generation of electricity from renewable sources of energy; etc.

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" in line with the Ministry of Power notified competitive bidding guidelines in 2005. The guidelines are being issued for procurement of electricity by distribution licensees for (a) long-term procurement of electricity for a period of 7 years and above; and (b) medium-term procurement for a period of upto 7 years but exceeding 1 year. The guidelines shall apply for procurement of base-load, peak load and seasonal power requirements through competitive bidding, through the mechanisms: (i) where location, technology, or fuel is not specified by the procurer (Case-1); and (ii) for hydro-power projects, load center projects or other location specific projects with specific fuel allocation such as

captive mines available, which the procurer intends to set up under tariff based bidding process (Case-2).

The power procurement through competitive bidding resulted in significant capacity addition in private sector. The details on tariff of inter-state power generating companies, mainly the tariff of central public sector power generating companies, have been provided below.

2. Tariff of Central Public Sector power generating companies

In 2018-19, the central public sector power generating companies (NTPC, NHPC, NLC, NEEPCO, etc.)/central government owned generating companies accounted for about 37% of the total power generation in the country. The entire generation of these central government owned generating companies is being procured by 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 2018-19 is shown in Table-36 and 37. It can be seen that, on an average, the distribution companies paid between ₹1.97 and ₹5.73 per kWh for procuring power from coal based stations, between ₹3.70 and ₹6.65 per kWh from gas based power stations, (Table-36), and between ₹1.16 per kWh and ₹8.46 per kWh from hydro stations (Table-37).

Table-36: Tariff of Central Thermal Power Stations, 2018-19

Sl. No.	Name of the Generating Station	Installed Capacity (MW) as on March, 2019	Fixed charges (₹/kWh)	Energy Charges (₹/kWh)	Total Tariff (₹/ kWh)
I: Coal Based thermal generating Stations of NTPC					
A.	**Pit head Generating Stations**				
1	Rihand STPS (St-I)	1000	0.86	1.32	2.18
2	Rihand STPS (St-II)	1000	0.71	1.32	2.03
3	Rihand STPS (St-III)	1000	1.46	1.34	2.80
4	Singrauli STPS	2000	0.66	1.37	2.03

5	Farrakka STPS (St-I&II)	1600	0.83	2.40	3.23
6	Farrakka STPS (St-III)	500	1.50	2.41	3.91
7	Kahalgaon STPS (St-I)	840	1.07	2.25	3.32
8	Kahalgaon STPS (St-II)	1500	1.10	2.15	3.25
9	Vindhyachal STPS (St-I)	1260	0.86	1.60	2.46
10	Vindhyachal STPS (St-II)	1000	0.70	1.50	2.20
11	Vindhyachal STPS (St-III)	1000	1.05	1.50	2.55
12	Vindhyachal STPS (St-IV)	1000	1.58	1.50	3.08
13	Vindhyachal STPS (St-V)	500	1.69	1.52	3.21
14	Korba STPS (St-I & II)	2100	0.69	1.28	1.97
15	Korba STPS (St-III)	500	1.40	1.26	2.66
16	Ramagundam STPS (St-I&II)	2100	0.73	2.57	3.30
17	Ramagundam STPS (St-III)	500	0.78	2.51	3.29
18	Talcher TPS	460	1.45	1.74	3.19
19	Talcher STPS (St-I)	1000	0.96	1.74	2.70
20	Talcher STPS (St-II)	2000	0.72	1.73	2.45
21	Sipat STPS (St-I)	1980	1.32	1.22	2.54
22	Sipat STPS (St-II)	1000	1.25	1.26	2.51
	Sub-Total (A)	**25840**			
B.	**Non-Pit head Generating Stations**				
23	FGUTPP TPS (St-I)	420	1.10	2.90	4.00
24	FGUTPP (St-II)	420	1.01	2.90	3.91
25	FGUTPP (St-III)	210	1.36	2.92	4.28
26	FGUTPP (St-IV)	500	1.53	2.82	4.35
27	NCTP Dadri (St-I)	840	0.99	3.69	4.68
28	NCTP Dadri (St-II)	980	1.45	3.43	4.88
29	Tanda TPS	440	1.28	2.84	4.12
30	Simhadri (St-I)	1000	0.95	2.86	3.81
31	Simhadri (St-II)	1000	1.53	2.87	4.40
32	Mauda STPS (St-I)	1000	1.89	2.98	4.87
33	Mauda STPS (St-II)	1320	1.50	2.86	4.36
34	Barh STPS (St-II)	1320	1.86	2.15	4.01
35	Bongaigaon TPS	750	2.67	3.06	5.73
36	Solapur STPS	1320	1.74	3.93	5.67
37	Kudgi STPS	2400	1.55	3.80	5.35
	Sub-Total (B)	**13920**			

	Total Coal (A+B)	**39760**			
II: Gas based Power Generating Stations of NTPC					
1	Anta CCGT	419	0.72	5.04	5.76
2	Auraiya GPS	663	0.64	6.01	6.65
3	Dadri CCGT	830	0.58	4.21	4.79
4	Faridabad GPS	432	0.76	3.43	4.19
5	Gandhar GPS	657	1.08	2.78	3.86
6	Kawas GPS	656	0.85	2.85	3.70
	Total	**3657**			
III: Gas based Power Generating Stations of NEEPCO					
1	Agartala GPS	84	1.54	2.58	4.13
2	Assam GPS	291	1.85	1.99	3.83
	Total NEEPCO	**375**			
IV: Lignite Based thermal generating Stations of NLC					
1	TPS-I	600	0.93	2.52	3.45
2	TPS-II Stage-I	630	0.72	2.33	3.05
3	TPS-II Stage-II	840	0.75	2.33	3.08
4	TPS-I (Expansion)	420	0.94	1.95	2.89
5	TPS-II (Expansion)	500	2.22	2.91	5.13
6	Barsingsar TPS	250	2.02	1.21	3.23
	Total NLC	**3240**			
V: Other Inter-state Coal based Power Generating Stations					
1	Indira Gandhi STPP, Stage-I	1500	1.55	2.32	3.87
2	Vallur TPP	1500	1.65	1.90	3.56
3	NTPL TPS	1000	1.46	2.10	3.56
4	Maithon Right Bank TPP	1050	1.39	2.41	3.79
5	Kamalanga Power Plant	1050	1.61	1.17	2.78
	Total	**6100**			
VI: Other Inter-state Gas based Power Generating Stations					
1	OTPC Ltd	727	1.70	1.19	2.89
2	Pragati Power Plant-III	1371	1.45	2.97	4.42
	Total	**2098**			

Table-37: Composite Tariff of Central Hydro Power Stations, 2018-19

Sr. No.	Name of the Generating Company/ Station	Type	Installed Capacity (MW)	Design Energy (MU)	Annual Fixed Charges (₹/Crore)	Composite Tariff (₹/kWh)
	NHPC					
1	Baira siul	Pondage	180	779	138	2.03
2	Loktak	Storage	105	448	150	3.84
3	Salal	ROR	690	3082	331	1.23
4	Tanakpur	ROR	123	452	130	3.29
5	Chamera-I	Pondage	540	1665	330	2.28
6	Uri-I	ROR	480	2587	370	1.64
7	Rangit	Pondage	60	339	112	3.80
8	Chamera-II	Pondage	300	1500	262	2.01
9	Dhauliganga-I	Pondage	280	1135	240	2.43
10	Dulhasti	ROR	390	1907	912	5.50
11	Teesta-V	Pondage	510	2572	520	2.32
12	Sewa-II*	Pondage	120	534	199	4.33
13	Chamera-III*	Pondage	231	1086	405	4.25
14	Chutak	ROR	44	213	145	7.85
15	Uri-II	ROR	240	1124	469	4.86
16	Nimoo Bazgo	Pondage	45	239	176	8.46
17	Teesta-LDP-III*	Pondage	132	594	361	6.20
18	Teesta-LDP-IV*	Pondage	160	581	162	2.56
19	Parbati-III	ROR	520	1977	520	3.02
	Total		**5150**	**22814**		
	NHDC					
1	Indira Sagar	Storage	1000	2247	529	2.70
2	Omkareshwar	Storage	520	957	398	4.78
	Total		**1520**	**3204**		
	THDC					
1	Tehri HPP Stage-I	Storage	1000	2767	1292	5.36
2	Koteshwar HEP	RoR with Pondage	400	1155	466	4.63
	Total		**1400**	**3922**		
	SJVNL					
1	Naptha Jhakri	RoR	1500	6924	1345	2.23
2	Rampur HEP	RoR	412	1878	697	4.27
	Total		**1912**	**8802**		
	NEEPCO					

1	Kopili HEP Stage-I	Storage	200	1186	120	1.16
2	Kopili HEP Stage-II	Storage	25	86	12	1.63
3	Khandong	Storage	50	278	44	1.81
4	Doyang	Storage	75	227	108	5.48
5	Ranganadi HEP	Pondage	420	1874	273	1.67
	Total		**770**	**3651**		

**Tariff is not determined yet for the year 2018-19, therefore, tariff allowed for billing is provided.*

Chapter-IV

Transactions of Renewable Energy Certificates

1. Background of 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, 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. These Regulations shall apply throughout India except the State of Jammu and Kashmir. 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 18 November 2010.

2. Trading of Renewble Energy Certificates on Power Exchanges

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 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 has been provided in Table-39. The number of RECs increased significantly from 10.15 lakh in 2011-12 to 126.00 lakh in 2018-19 and the annual growth was registerd at the rate of 43%. The number of buyers and sellers also increased from 397 and 197 respectively in 2011-12 to 988 and 830 in 2018-19. It can be observed from the table that there was negative growth of 22% in number of RECs transacted in 2018-19. This could be for the reason that the state utilities may be buying more RE power which is relatively cheaper than buying RECs and non-RE power.

Table-39: Growth of Renewable Energy Certificates transacted on Power Exchanges, 2011-12 to 2018-19

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%

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 2018-19. In case of Solar RECs, the volume of buy bid as percentage of volume of sell bid varied between 1% and 57% whereas in case of Non-solar RECs the volume of buy bid as percentage of volume of sell bid varied between 3% and 229% in both power exchanges during the period 2013-14 to 2018-19. It can be inferred from the data that the demand for both solar and non-solar RECs was very high in 2018-19. The demand for non-solar RECs is relatively high when compared with the demand for solar RECs.

Table-40: Demand and Supply of RECs on Power Exchanges, 2012-13 to 2018-19

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%
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%

The volume and price of RECs transacted on both power exchanges during 2012-13 to 2018-19 has been provided in Table-41. It can be observed from the table that there is an increasing trend in the volume of both solar and non-solar RECs transacted on both power exchanges and there is a declining trend in the weighted average of market clearing price of the RECs. The increase in the volume of RECs transacted on power exchanges can be attributed to the increase in the RPO compliance. 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 i.e. by reducing the floor and forbearance price.

The market clearing volume of Solar RECs transacted on both power exchanges increased from 0.14 lakhs in 2012-13 to 71.95 lakhs in 2018-19, whereas the weighted average of market clearing price of these RECs declined from ₹12740/MWh in 2012-13 to ₹1097/MWh in 2018-19. The market clearing volume of

Non-Solar RECs transacted on both power exchanges increased from 25.76 lakhs in 2012-13 to 159.76 lakhs in 2017-18 and then sharp declined to 51.98 lakhs in 2018-19, whereas the weighted average of market clearing price of these RECs declined from ₹1692/MWh in 2012-13 to ₹1293/MWh in 2018-19.

Table-41: Volume and Price of RECs Transacted on Power Exchanges, 2012-13 to 2018-19

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
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

Consequent to the revised floor and forbearance price issued by CERC vide order dated 30.03.2017, Supreme Court had put stay on trading of the RECs. While trading of Non-Solar REC 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, CERC extended the validity of the RECs upto 31.03.2018. These developments resulted to a significant increase in the market clearing volume of Solar RECs on both the power exchanges, from 2.08 lakhs in 2017-18 to 71.95 lakhs in 2018-19 (Table-41).

In May 2018, Ministry of New and Renewable Energy, 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. Further in June 2018, Ministry of Power notified the long term growth trajectory of RPOs for Solar and Non solar for a period of three years from 2019-20 to 2021-22 (Table-42).

Table-42: Long-term Growth Trajectory of RPOs, 2019-20 to 2021-22

Type of RPOs	2019-20	2020-21	2021-22
Non-Solar	10.25%	10.25%	10.50%
Solar	7.25%	8.75%	10.50%
Total	17.50%	19.00%	21.00%

Annexure-I

List of Transmission Licensees as on 31.03.2019

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

Annexure-II

List of Trading Licensees as on 31.3.2019

Sr. No.	Name of Trading Licensee	Date of Issue of License	Present 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	I
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	I
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	I
16	Kreate Energy (I) Pvt. Ltd.	12-02-2009	II
17	Shree Cement Ltd	16-03-2010	I
18	Jai Prakash Associates Ltd	23-03-2011	I
19	ABJA Power Pvt. Ltd.	26-04-2011	III
20	Customised Energy Solutions India (P) Ltd	08-06-2011	III
21	Statkraft Markets (P) Ltd	21-06-2012	I
22	Manikaran Power Ltd	29-06-2012	I
23	Arunachal Pradesh Power Corporation (P) Ltd	11-09-2012	II
24	Vedprakash Power (P) Ltd	19-08-2013	IV
25	Solar Energy Corporation of India	01-04-2014	I
26	Parshavnath Power Projects (P) Ltd	19-05-2014	IV
27	IL&FS Energy Development Company Ltd	04-09-2014	I
28	IPCL Power Trading (P) Ltd	10-02-2015	III

29	Gita Power & Infrastructure (P) Ltd	20-10-2015	III
30	Phillip Commodities India Pvt. Ltd.	21-01-2016	IV
31	Renew Solar Services Pvt. Ltd.	27-01-2017	IV
32	Amplus Energy Solutions Private Limited	17-04-2017	II
33	Atria Energy Services Private Limited	20-06-2017	IV
34	Jindal Poly Films Limited	20-09-2017	III
35	NHPC Limited	23-04-2018	I
36	NLC India Ltd.	13-07-2018	I
37	Refex Energy Ltd.	30-08-2018	I

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 / yi-1).
2. yi 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:

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

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 one, where *N* is the number of firms in the market. Equivalently, if percents 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 one, the normalized Herfindahl index ranges from 0 to 1.