MINUTES OF THE 64th MEETING OF THE

FORUM OF REGULATORS (FOR) HELD AT RANCHI, JHARKHAND

Venue	**:**	**Utsav Hall** **Hotel Chanakya BNR, Ranchi**
Day / Date	**:**	**Friday, the 24th August , 2018**
List of Participants	**:**	**At Annexure-I (Enclosed)**

The meeting was chaired by Shri P.K.Pujari, Chairperson, Central Electricity Regulatory Commission (CERC) and Forum of Regulators (FOR). The Chairperson, CERC/ FOR welcomed all the Members of the Forum to the Meeting. He specifically welcomed Chairperson, Delhi Electricity Regulatory Commission and Chairperson, Rajasthan Electricity Regulatory Commission who were attending the meeting for the first time after they took over charge in their respective offices.

Thereafter, the Forum took up the agenda items for consideration.

BUSINESS SESSION – I

AGENDA ITEM NO. 1: CONFIRMATION OF THE MINUTES OF THE 63rd MEETING OF THE FORUM OF REGULATORS HELD ON 9th APRIL 2018 AT NEW DELHI.

The Forum endorsed the minutes of the 63rd Meeting of "FOR", held on 9th April, 2018 at New Delhi.

AGENDA ITEM NO. 2 : APPROVAL AND ADOPTION OF THE AUDITED ANNUAL ACCOUNTS OF "FOR" FOR FY 2017-18.

The members observed from the Schedules of the Accounts that FOR has applied for exemption under section 10(46) of the Income Tax 1961 and that the amount of contingent liability that may arise in the event of not getting Income tax exemption has not been ascertained and provided for. Hence, it was felt that the liabilities be earmarked and provision for tax payable be made in the books of account, in case exemption is not granted by IT authorities.

The members also observed that there has been considerable increase in FOR secretariat expenses paid to CERC vis-a-vis the previous year. It was clarified that the increase in expenses is based on an approved model and corresponds to just 1/10th of the total costs being paid by CERC towards rent/ utility charges etc. The members while accepting the justification stated that the component of expenses for capacity building programs should be increased, which was otherwise showing a downward trend vis-à-vis the previous year.

With the above observations, the Forum considered and approved the Balance Sheet and Audited Accounts of "FOR" for FY 2017-18.

AGENDA ITEM NO. 3: LAUNCH OF REPORT OF POSOCO ON "RENEWABLE ENERGY CERTIFICATE MECHANISM IN INDIA"

Chairperson, CERC, JSERC and GERC released the POSOCO report on "Renewable Energy Certificate Mechanism in India". A presentation was made by representative of POSOCO (copy enclosed as **Annexure-I**).

After discussion, the Forum took the report on record. Some members sought to have a relook into the REC mechanism in the context of reduction/ changes in cost of RE generation as well as anticipated shortfall against the RPO targets specified by the Ministry of Power. Shri S.K.Soonee, Advisor, POSOCO clarified that REC is a fungible commodity and that it would serve those States who are not RE rich. In this matter, the Forum was informed that CERC is in the process of taking up a Study on Regulatory Impact Assessment of RECs and the issues as raised by the members regarding relevance of REC mechanism in the context of current scenario will get covered in the said study.

AGENDA ITEM NO.4: MODEL REGULATIONS AND REPORT ON "GAP ASSESSMENT FOR COMPREHENSIVE METERING AND ACCOUNTING FRAMEWORK FOR GRID CONNECTED SOLAR ROOFTOP PV IN INDIA"

A study, supported by the World Bank [under Perform for Results (PFR) lending instrument to the State Bank of India (SBI)] has been commissioned to update the FOR Model Net metering Regulation, 2013 so as to develop a "Comprehensive metering and Accounting framework for Rooftop Solar PV in India". The study aims to identify challenges in the regulatory framework based on upcoming business models, available infrastructure for deployment, and impact on various stakeholders; and propose necessary changes in the existing regulation. The project team after conducting detailed techno-commercial review of the extant regulatory framework in various States and comparative assessment of global best practices in its Gap Assessment Report, has suggested possible business models for adoption by the States in their Report. A presentation with suggested business models along with simulation results was made by the team of consultants (at **Annexure-II A & B**) , the Report on the Gap Assessment (**Annexure III**) and Model regulation for grid connected solar rooftop projects (**Annexure-IV**) was also presented.

The Forum considered the Model Regulations and the Report and directed FOR Secretariat to seek comments from SERCs/JERCs within 15 days. After compiling the comments received and incorporating them into the Report and Model Regulations, the same was directed to be presented in the next FOR meeting for finalisation.

BUSINESS SESSION – II

SHRI RAGHUBAR DAS, HON'BLE CHIEF MINISTER OF JHARKHAND JOINED THE "FOR" MEETING

Shri P.K.Pujari, Chairperson, CERC in his welcome address extended a warm welcome to the Hon'ble Chief Minister of Jharkhand and thanked him for accepting the invitation to grace the 64th Meeting of FoR. He stated that Jharkhand has a vibrant growth story in the energy sector as the State has, to its credit, adequate power generation capacity due to excellent policy support from the State Government and able regulatory mechanism in place. He also informed that the two decades of reforms in the power sector in the country has witnessed positive outcomes such as capacity addition in generation, improvement of operating efficiency and availability of power plants, evolution of short term market, growth in transmission segment. This was made possible only due to combined efforts of Government, Regulators and stakeholders. He also elaborated on the key activities of the Central Commission and the Forum of Regulators. He concluded by stating that as Electricity is a concurrent subject, the Centre and State necessarily need to work in a coordinated way and requested Hon'ble Chief Minister to share his thoughts and insights.

Shri Raghubar Das, Hon'ble Chief Minister in his address to the Forum stated that he was delighted to inaugurate the meeting of Regulators in the capital city of Jharkhand. During his address, he spoke about the government's priority to promote Renewable Energy in the State by setting a target to generate 4000 MW by 2022 through various sources including renewables. On electrification of households, he stated that out of 68 lakh households in the State, only 30 lakh families had electricity till 2014. Now electricity has reached 49 lakh families in the State and rest of the families will have power by the end of this year. He commended the State Electricity Regulatory Commission of Jharkhand for their regulatory initiatives and announced that very soon the Government would be sanctioning a new building to house the JSERC. He added that Jharkhand is likely to be the country's first State to roll out direct benefit transfer mechanism for power subsidy as Central Government has selected the State as pilot to introduce the scheme. He wished the Forum would have fruitful discussions during the course of the meeting.

On conclusion of this session, Dr Arbind Prasad, Chairperson, JSERC proposed vote of thanks. In his address, he informed that JSERC had approved enhanced tariff for different categories of consumers and the State Government had offered subsidy so that the consumers are not burdened to pay enhanced tariff. The DBT Scheme of the Government will help government target electricity subsidies in a better manner without leakage. Besides, it would also provide an opportunity to consumers to buy electricity from a power company of their choice. He thanked the Hon'ble Chief Minister for addressing and interacting with the Members of the Forum.

BUSINESS SESSION – III

AGENDA ITEM NO. 5: REFERENCE FROM CENTRAL ELECTRICITY AUTHORITY, MINISTRY OF POWER ON NATIONAL LEVEL DATA REGISTRY

Joint Chief (RA), CERC appraised the Forum of the reference received from CEA requesting CERC/ SERCs/ JERCs to suitably amend their Tariff Regulations, RE Tariff Regulations and Solar roof top regulations to direct all electricity generating units above a specified capacity to mandatorily register with the National Level Data Registry system. This will enable every licensee to furnish statistics and other information relating to generation, transmission, distribution and trading to CEA through this Registry. This would ensure that all database is centrally maintained. The Forum noted the proposal for appropriate action by the SERCs.

AGENDA ITEM NO. 6: DEVELOPMENT OF ELECTRICITY REGULATORY INFORMATION ACCESS

AND ANALYTICAL PLATFORM – PARTNERSHIP BETWEEN MINISTRY OF POWER, GOVERNMENT OF UK AND FOR

Joint Chief (RA), CERC informed the Forum about the partnership of Ministry of Power (MoP), (Government of India) with the Department for International Development (DFID), Government of UK under the "Supporting Structural Reforms in the Indian Power Sector" (Power Sector Reforms Programme)" which is primarily to support structural reforms in the Indian power sector and integration of renewable energy into the electricity grid. FOR is being supported for capacity development of Regulatory Institutions in India including strengthening of monitoring frameworks. Under this program, the consultant is assisting FOR to develop an online platform on the website of the FOR to make available the comparative information across the States on the platform. In the initial phase, data will be sought from Maharashtra ERC, Uttar Pradesh ERC, Jharkhand SERC, Telangana SERC and Assam ERC which will be later extended to the SERCs/ JERCs.

The Forum accorded in-principle approval to this proposal and advised that the formats so developed should be shared with all SERCs/ JERCs for their comments and consideration.

AGENDA ITEM NO. 7: ELECTRICITY REGULATOR MANAGEMENT SYSTEM (ERMS) IN WEST BENGAL ELECTRICITY REGULATORY COMMISSION

The consultant engaged by WBERC (M/s KPMG) made a presentation **(Annexure V)** on the ERMS developed for WBERC. This system assists the Commission in validating data submitted by the licensees by capturing petition data and external data. The various statistical models in this system enable projections on various technical parameters and assists the Commission to conduct internal computation for admitting values on technical and financial parameters before issuing its Orders. The existing database in the system also assists the Commission to conduct benchmarking exercise on various parameters.

The Forum noted the ERMS in WBERC.

AGENDA ITEM NO. 8: MODEL REGULATIONS & REPORT OF FOR ON POWER QUALITY

Ms Shilpa Agarwal, Jt. Chief (Engg), CERC made a presentation **(Annexure VI)** on the Report on Power Quality. She explained the genesis of the Working Group of FOR which was constituted with Chairpersons and Members of CERC and SERCs and technical experts to review the action initiated by various Regulating Agencies in line with the provisions of the Electricity Act 2003 and international practice and to suggest possible further improvements. The Working Group further constituted a Sub Group under the Chairpersonship of Shri A.S.Bakshi, Member (now retired), CERC and representatives from SERCs, CEA, PGCIL and other technical experts. Case studies in the steel wire rope industry (Industry Sector), Hospital (Service Sector), Food & Beverage Industry and Utility Sector were conducted.

The Report of the Sub Group identified comprehensive study area to improve Power Quality (PQ) performance, explored present legal frameworks and global regulatory scenario and deliberated/ recommended the following:

a. Need for Power Quality Regulations.

b. Reliability Indices (SAIFI, SAIDI)to be part of the PQ Regulations

c. Monitoring of Power Quality parameters at Transmission and Sub-Transmission System Level.

d. Power Quality Parameters such as Harmonic Distortion, Voltage Variation & Flicker, Voltage Unbalance, Voltage Sags/Swells and Short & Long Supply Interruptions need to be specified in PQ Regulations

e. Locations for Power Quality Monitoring.

f. Incentive/ Dis-incentive Mechanism for Power Quality.

g. Integration of Power Quality with Smart Grid Applications in Distribution.

h. Power Quality Database.

i. Trainings in the area of Power Quality.

j. Power Quality Audits.

The Sub Group also formulated Model Regulations on Power Quality **(Annexure VII)** which will apply to Distribution Licensee(s) including Deemed Distribution Licensee(s), distribution franchisees and all Designated Customer(s) of electricity connected at or below 33kV voltage level. Further, the Model Regulations have defined power quality indices, roles and responsibilities of various entities, standards/ limits to be followed, incentive/ disincentive mechanism and procedure for monitoring, management and control of all aspects of power quality.

The Forum endorsed the Report on Power Quality.

AGENDA ITEM NO. 9: NATIONAL OPEN ACCESS REGISTRY (NOAR) – BRIEF

Joint Chief (RA), CERC informed the Forum of the Staff paper on National Open Access Registry brought out by CERC which envisaged the automation of the process of Open Access transactions. The staff paper received positive response from stakeholders as they felt it would bring in greater transparency and efficiency in the processes involving open access transactions. Accordingly, CERC has decided to go ahead with NOAR and has also proposed to amend the CERC Open Access Regulations for Inter State transmission suitably. Draft amendments to relevant Regulations have already been floated for public comments.

NLDC (POSOCO) will be the nodal agency for this purpose. Representative of POSOCO made a presentation **(Annexure VIII)**. In their presentation, POSOCO elaborated on the proposed mechanism on the Registry including financial transactions and market monitoring.

The Forum noted the NOAR initiative of CERC and opined that Members of the Forum could support this initiative and impress upon the concerned stakeholders (including SLDC) to help ease the process of Open Access transactions as envisaged by CERC.

AGENDA ITEM NO. 10: ANY OTHER ITEMS WITH THE PERMISSION OF THE CHAIR.

10(i): Reference from Maharashtra ERC regarding building infrastructure for SERCs

The Member, Maharashtra Electricity Regulatory Commission sought permission of the Chair for placing a proposal relating to building infrastructure for SERCs wherein State Governments can be requested to provide own land and buildings for SERCs. He contended that this proposal was in line with judgement of Hon'ble Supreme Court which advocated for providing infrastructure support to Regulatory bodies.

The Forum noted the proposal.

10(ii): Model Staff structure

Chairperson, JSERC remarked that ERCs are not adequately staffed and that there is a need to have an analysis regarding the required sanctioned strength so that they could approach the respective Governments with a proposal. In this regard, Joint Chief (RA), CERC appraised the Forum of the Report of FOR on staffing requirements. After deliberations, the Forum concurred to the suggestions made by the members that that SERCs are required to be provided with adequate staff strength. It was agreed that the previous report of FOR on the same subject may be revisited with analysis of the composition of staff strength in SERCs/ JERCs and other regulatory bodies.

10(iii): Forum of Distribution utilities

Chairperson, WBSERC informed the Forum that there is a need to constitute a Forum which will discuss the issues faced by licensees. After discussion, the Forum agreed to explore the possibility of holding a meeting with Heads of Distribution licensees back to back through the MoP monthly meetings of "Review, Planning & Monitoring"

On conclusion of the meeting, Secretary, CERC/ FOR thanked the Chairperson, Members, Secretary and staff of the Jharkhand State Electricity Regulatory Commission (JSERC) for their painstaking efforts to host the 64^{th} Meeting of FOR at Ranchi. He also thanked all the dignitaries present in the meeting. He thanked the staff of "FOR" Secretariat for their arduous efforts in organizing the meeting. He also conveyed to the Members of Forum that as proposed by Chairperson, Odisha SERC, the next "FOR" Meeting will be held in Bhubaneswar on November 13^{th}, 2018.

The meeting ended with a vote of thanks to the Chair.

Appendix-I

LIST OF PARTICIPANTS OF THE 64^{TH} MEETING OF

FORUM OF REGULATORS (FOR) HELD ON 24^{TH} AUGUST, 2018 AT RANCHI, JHARKHAND

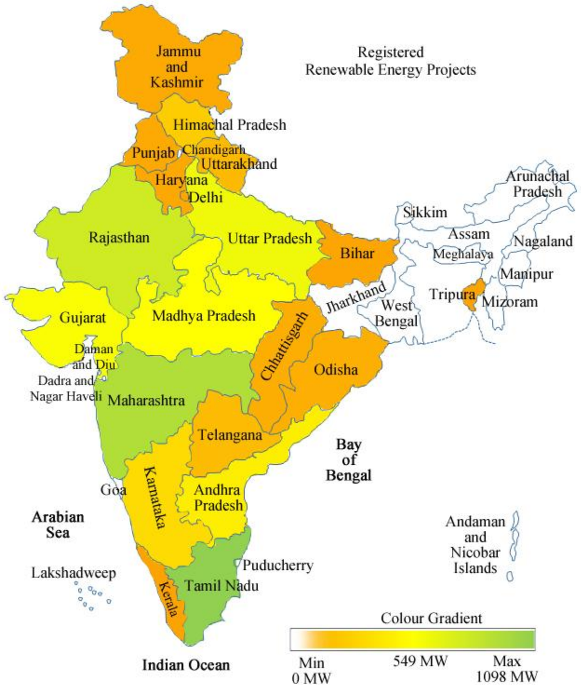
S.NO.	NAME AND DESIGNATION	ERC
1.	Shri P.K.Pujari Chairperson	CERC – in chair
2.	Shri S. Akshayakumar Chairperson	TNERC
3.	Shri Jagjeet Singh Chairperson	HERC
4.	Justice G. Bhavani Prasad Chairperson	APERC
5.	Shri Subhash Kumar Chairperson	UERC
6.	Shri Ismail Ali Khan Chairperson	TSERC
7.	Shri Dev Raj Birdi Chairperson	MPERC
8.	Shri Rabindra Nath Sen Chairperson	WBERC
9.	Shri M.K. Shankaralinge Gowda Chairperson	KERC
10.	Shri S.K.B.S. Negi Chairperson	HPERC

11.	Shri S.K. Negi Chairperson	BERC
12.	Shri Er. Imlikumzukao Chairperson-cum-Member	NERC
13.	Shri Anand Kumar Chairperson	GERC
14.	Shri R.P. Singh Chairperson	APSERC
15.	Shri U.N. Behera Chairperson	OERC
16.	Dr Arbind Prasad Chairperson	JSERC
17.	Ms. Kusumjit Sidhu Chairperson	PSERC
18.	Shri Ngangom Sarat Singh Chairperson	JERC for Manipur & Mizoram
19.	Justice S.S.Chauhan Chairperson	DERC
20.	Shri Shreemat Pandey Chairperson	RERC
21.	Shri Sanoj Kumar Jha Secretary	CERC
21.	Dr. S.K. Chatterjee , Joint Chief (Regulatory Affairs)	CERC
	SPECIAL INVITIEES	
22.	Shri A.K. Singhal, Member	CERC
23.	Shri R.N. Singh Member	JSERC

24.	Shri S.K.Aggarwal Member	UPERC
25.	Shri I.M. Bohari Member	MERC
	POSOCO/OTHERS	
26.	Shri K.V.S. Baba CMD	POSOCO
27.	Shri S.K.Soonee Advisor	POSOCO
28	Sri S.C.Saxena DGM	POSOCO
29.	Shri Shailendra Verma Manager	POSOCO
30	Ms Shilpa Agarwal Joint Chief Engg	CERC

Annexure-I

REC Mechanism
Key learnings, Data analysis and Way forward



Central Agency, National Load Despatch Centre
Power System Operation Corporation Limited

Contents of the Report

- **Presents a holistic picture**
- **Learnings from the data analytics**
- **Ready reckoner for stakeholders**
- **Useful for Policy Makers, Regulators…**

Regulatory framework

- **CERC REC Regulations 2010** **(and 4 amendments)**
- **SERC Regulations- 29 SERCs/JERCs have notified the RPO Regulations/Orders**

S. No.	Name of ERC
1	Andhra Pradesh
2	Arunachal Pradesh
3	Assam
4	Bihar
5	Chhattisgarh
6	Delhi
7	Gujarat
8	Haryana
9	Himachal Pradesh
10	Jammu and Kashmir
11	Jharkhand
12	Karnataka
13	Kerala
14	Madhya Pradesh
15	Maharashtra
16	Meghalaya

S. No.	Name of ERC
17	Nagaland
18	Odisha
19	Punjab
20	Rajasthan
21	Sikkim
22	Tamil Nadu
23	Telangana
24	Tripura
25	Uttar Pradesh
26	Uttarakhand
27	West Bengal
28	JERC- Manipur, Mizoram
29	JERC- Chandigarh, Lakshadweep, Andaman & Nicobar Islands, Goa, Daman & Diu, Dadra & Nagar Haveli, Puducherry

REC Portal Home Page | https://www.recregistryindia.nic.in

Welcome Guest

भारतीय अक्षय ऊर्जा प्रमाणपत्र पंजीकरण
RENEWABLE ENERGY CERTIFICATE REGISTRY OF INDIA

मुख्य पृष्ठ / Home | आरईसी के बारे में / About REC | संबंधित दस्तावेज़ / Reference Documents | कार्यप्रणाली / Procedures | आरई जेनरेटर / RE Generators | डिस्कॉम / DISCOM | राज्य एजेंसियां / State Agencies | रिपोर्ट / Reports | सहायता / Help | हमसे संपर्क करें / Contact Us

पंजीकरण/निर्गमन जांच सूची / Registration / Issuance Checklist | पंजीकरण/निर्गमन शुल्क / Registration / Issuance Fee | क्षमता अभिवृद्धि / Capacity Building | मानचित्र / Map | डाक प्रक्रिया / Dak Procedure | साइटमैप / Sitemap

What is REC?

The Electricity Act, 2003, the policies framed under the Act, as also the National Action Plan on Climate Change (NAPCC) provide for a roadmap for increasing the share of renewable in the total generation capacity in the country.However, Renewable Energy (RE) sources are not evenly spread across different parts of the country. Read More >>

Total Signed Up RE Generators Till Now - 3162

Steps for REC 4 of 4

STEP 4 Redemption of REC

The basic procedure for redemption of renewable energy certificates shall include following steps:

STEP 4: The Eligible Entity shall place for dealing of renewable energy certificates, both 'Solar' and 'Non-Solar' Certificates, on any Power Exchange authorised to deal in renewable energy certificates by CERC.
Read More >>

REC Summary

Month, Year	Opening Balance (A)	REC Issued (B)	No. of REC Redeemed		Total E=(C+D)	Closing Balance (F=A+B-E)
			RECs Redeemed through Power Exchanges (C)	RECs retained by RE Generators (D)		
Sep, 2017	18529600	476338	382007	27493	409500	18596438
Oct, 2017	18596438	564523	487105	42471	529576	18631385
Nov, 2017	18631385	620311	2207622	53215	2260837	16990859
Dec, 2017	16990859	837960	5217189	104415	5321604	12507215
Jan, 2018	12507215	667587	1230826	55514	1286340	11888462
Feb, 2018	11888462	336128	2358396	25004	2383400	9841190
Mar, 2018	9841190	492681	2769433	72153	2841586	7492285
Apr, 2018	7492285	330789	1062661	28704	1091365	6731709
May, 2018	6731709	508088	1316021	27109	1343130	5896667
June, 2018	5896667	559772	896229	63960	960189	5496250
Jul, 2018	5496250	411421	1618069	52150	1670219	4237452
Aug, 2018	4237452	5282	0	0	0	4242734
Total:		47913354	41936151	1734469	43670620	

Log In

Password

Log In »

Forget/Resend Password

Sign Up RE Generators

Sign Up Discom

Related Links

- MNRE
- MoP
- CERC
- FOR
- Central Agency/NLDC
- SERCs
- State Agencies
- Power Exchange

Visitor Number - 7043812

Photo Gallery

Experience of management of REC registry

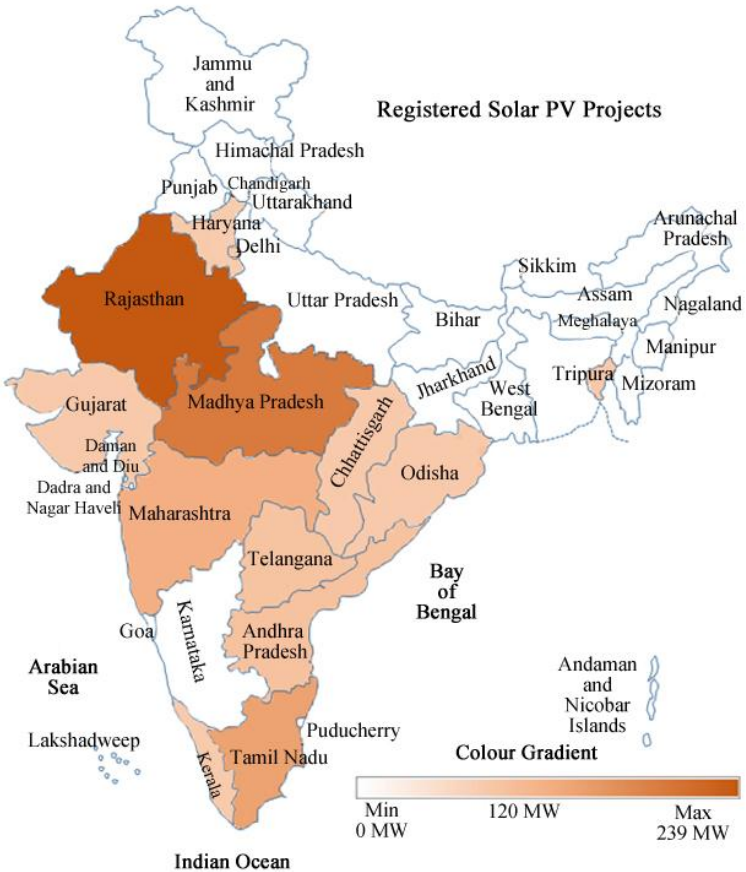
- Online payment gateway integrated w.e.f. August 2017
- Expenditure incurred ~ approx. 14 crore (0.25% of total value of transactions)
- Knowledge dissemination - technical papers, conferences, stalls etc.
- 27 workshops organized - on an average 30 officials trained
- More than 40 petitions have been filed in by the RE generators

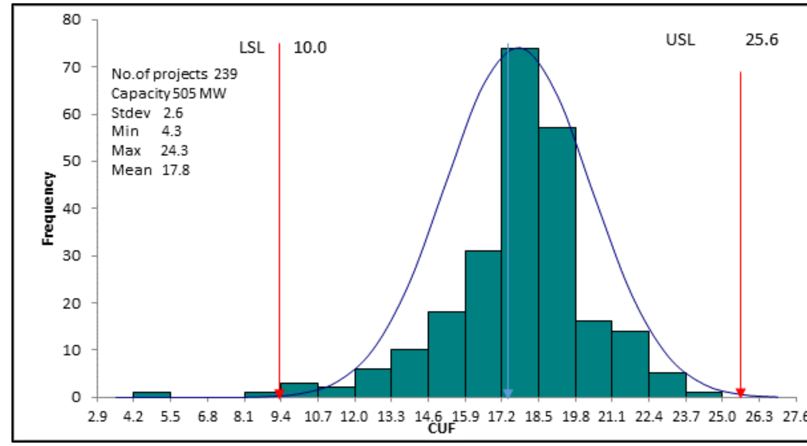
Key Highlights

- Transparent
- User Friendly
- Real Time Data
- Single Touch Point for information

About POSOCO | Privacy Policy

Registered Solar PV Projects

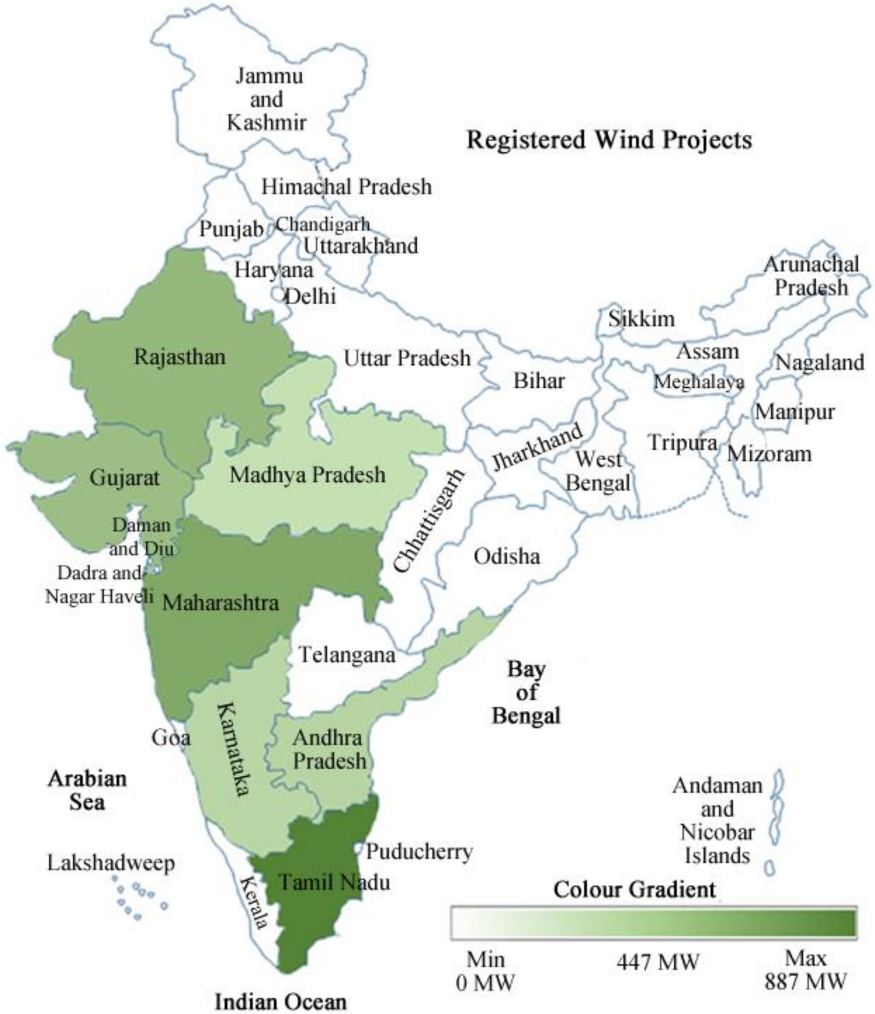


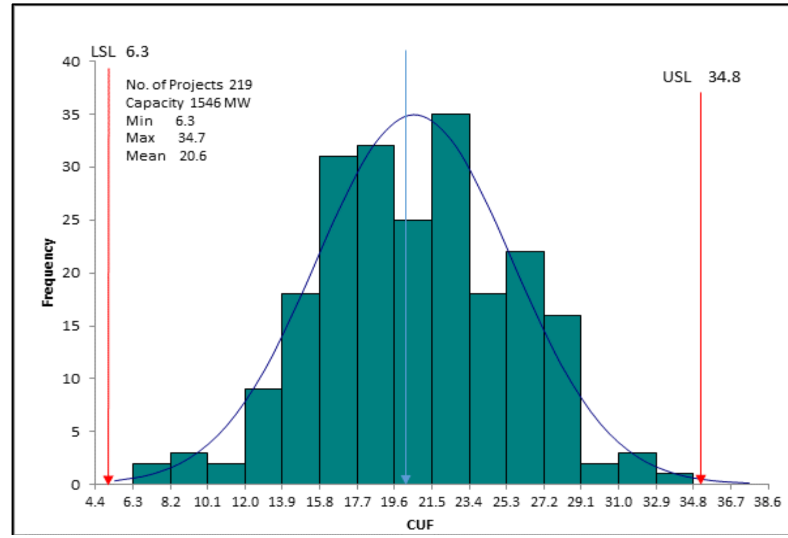


S. No.	State	No. of Projects	Capacity (MW)
1	Rajasthan	104	239
2	Madhya Pradesh	99	182
3	Maharashtra	62	99
4	Tamil Nadu	56	121
5	Andhra Pradesh	16	36
6	Telangana	10	28
7	Gujarat	4	7
8	Odisha	3	5
9	Delhi	2	8
10	Haryana	1	1
11	Chhattisgarh	1	5
12	Kerala	1	1
13	Tripura	1	5
	Total	**360**	**736**

Accreditation						Registration						Breakup of RECs			
Total		Revoked/ Expired		Net		Total		Revoked/ Expired		Net		Issued	Redeemed through		Closing Balance
No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)		PXs	Self Retaintion	
394	792	18	38	376	754	373	756	13	20	360	736	7,650,653	1,653,478	82,539	5,914,636

Registered Wind Projects





S. No.	State	No. of Projects	Capacity (MW)
1	Tamil Nadu	172	887
2	Maharashtra	161	454
3	Gujarat	32	227
4	Rajasthan	22	361
5	Andhra Pradesh	14	125
6	Karnataka	11	107
7	Madhya Pradesh	1	6
	Total	**413**	**2,167**

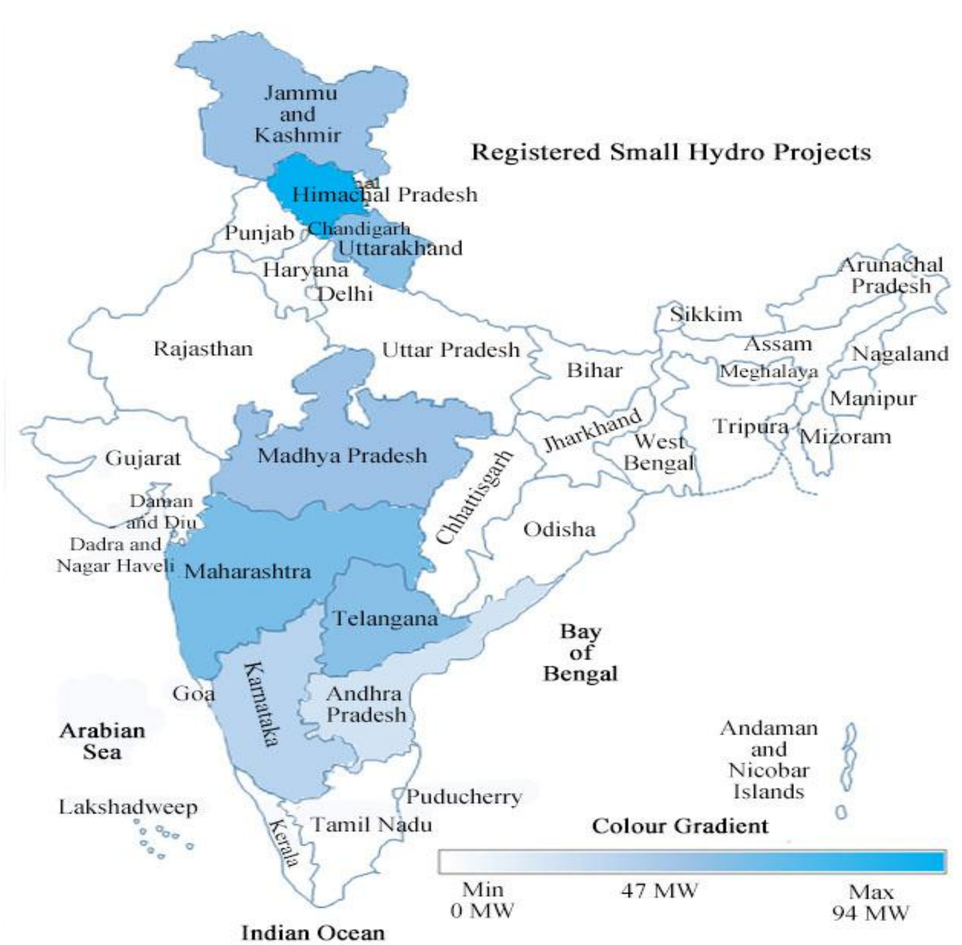
Accreditation						Registration						Breakup of RECs			
Total		Revoked/ Expired		Net		Total		Revoked/ Expired		Net		Issued	Redeemed through		Closing Balance
No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)		PXs	Self Retaintion	
699	2,934	266	703	433	2,231	664	2,781	251	614	413	2,167	18,145,199	16,090,035	1,324,427	730,737

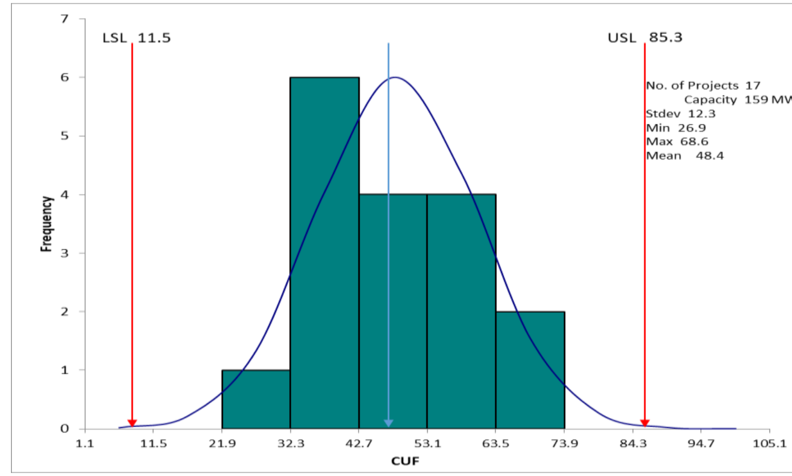
Registered Bio-fuel Cogeneration Projects

S. No.	State	No. of Projects	Capacity (MW)
1	Maharashtra	30	236
2	Uttar Pradesh	17	134
3	Gujarat	6	21
4	Uttarakhand	4	18
5	Tamil Nadu	1	10
6	Haryana	1	3
7	Punjab	1	5
8	Bihar	1	6
Total		61	431

Accreditation						Registration						Breakup of RECs			
Total		Revoked/ Expired		Net		Total		Revoked/ Expired		Net		Issued	Redeemed through		Closing Balance
No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)		PXs	Self Retaintion	
136	1,214	35	303	101	911	128	1,138	67	707	61	431	7,284,244	7,146,768	5,001	132,475

Registered Small Hydro Projects

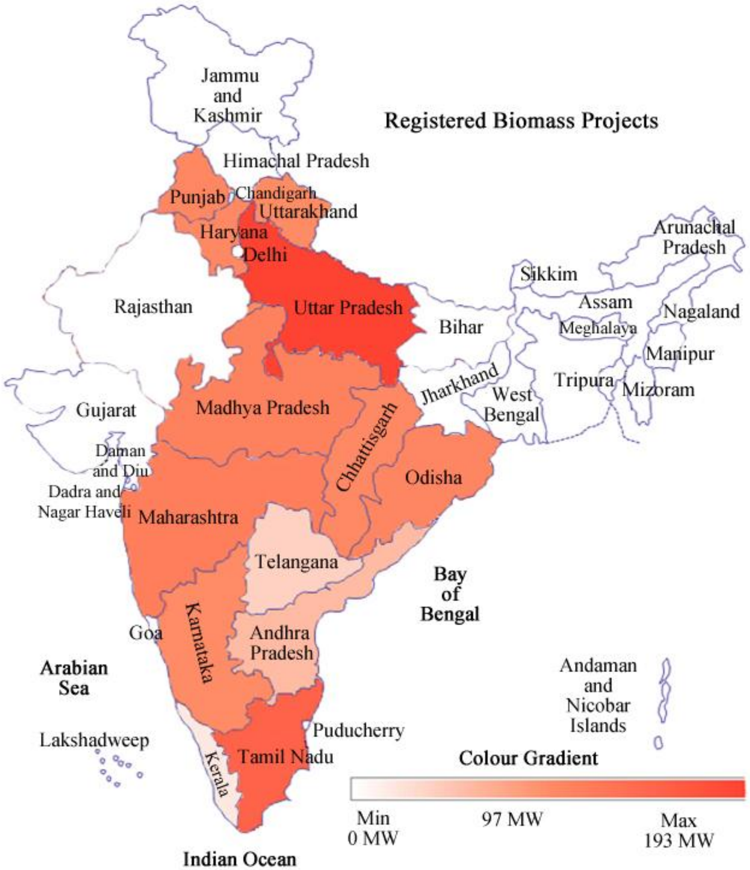




S. No.	State	No. of Projects	Capacity (MW)
1	Himachal Pradesh	13	94
2	Maharashtra	10	32
3	Karnataka	2	10
4	Madhya Pradesh	1	14
5	Andhra Pradesh	1	1
6	Telangana	1	24
7	Uttarakhand	1	24
8	Jammu and Kashmir	1	15
Total		30	212

Accreditation						Registration						Breakup of RECs			
Total		Revoked/ Expired		Net		Total		Revoked/ Expired		Net		Issued	Redeemed through		Closing Balance
No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)		PXs	Self Retaintion	
54	493	20	263	34	230	47	412	17	200	30	212	3,732,562	3,718,347	6,616	7,599

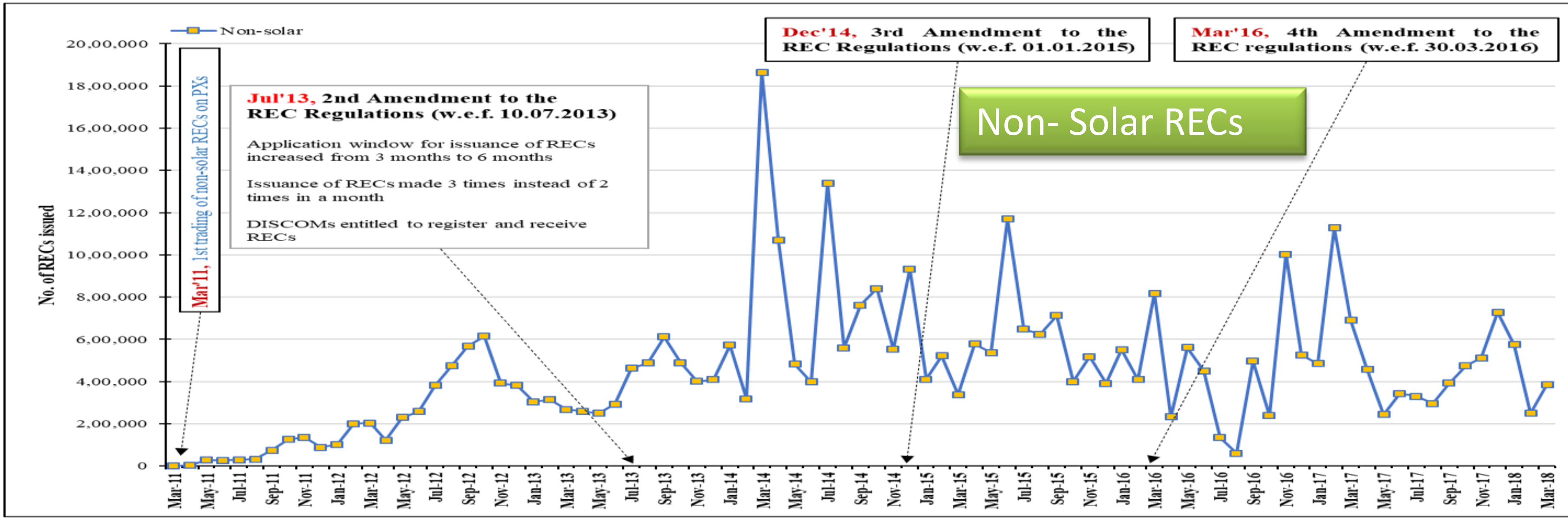
Registered Biomass Projects

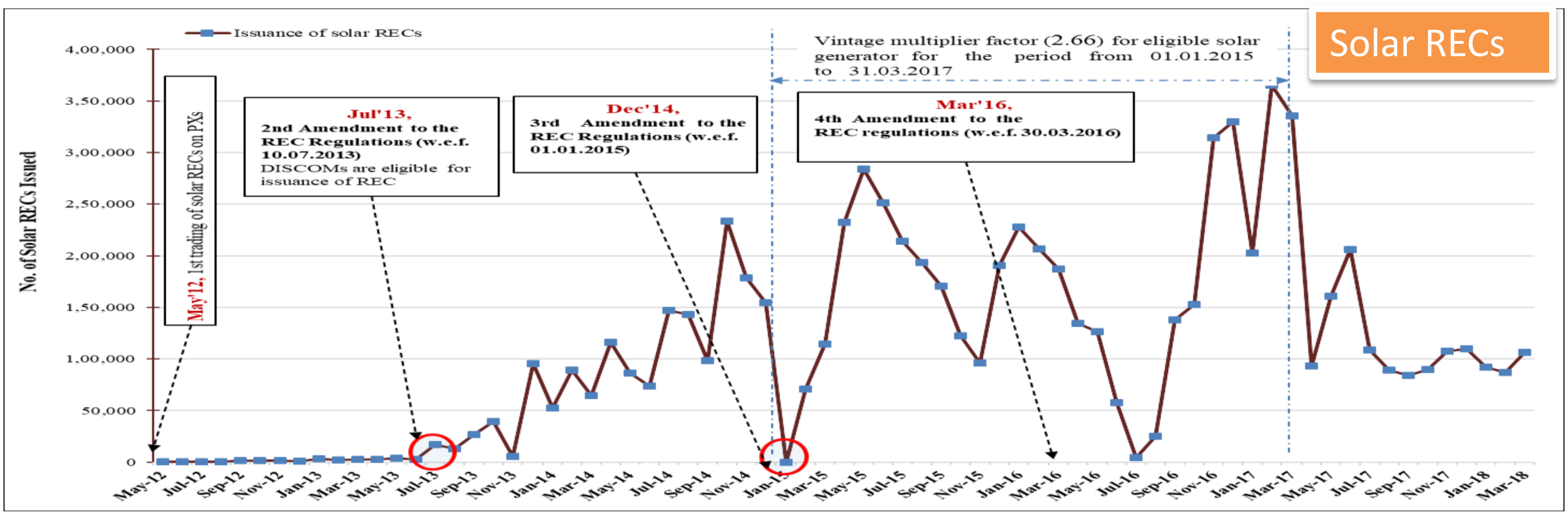


S. No.	State	No. of Projects	Capacity (MW)
1	Uttar Pradesh	14	193
2	Tamil Nadu	10	81
3	Maharashtra	5	28
4	Haryana	4	11
5	Madhya Pradesh	1	4
6	Andhra Pradesh	1	6
7	Karnataka	1	10
8	Telangana	1	4
9	Uttarakhand	1	10
10	Odisha	1	25
11	Punjab	1	10
12	Chhattisgarh	1	20
	Total	41	401

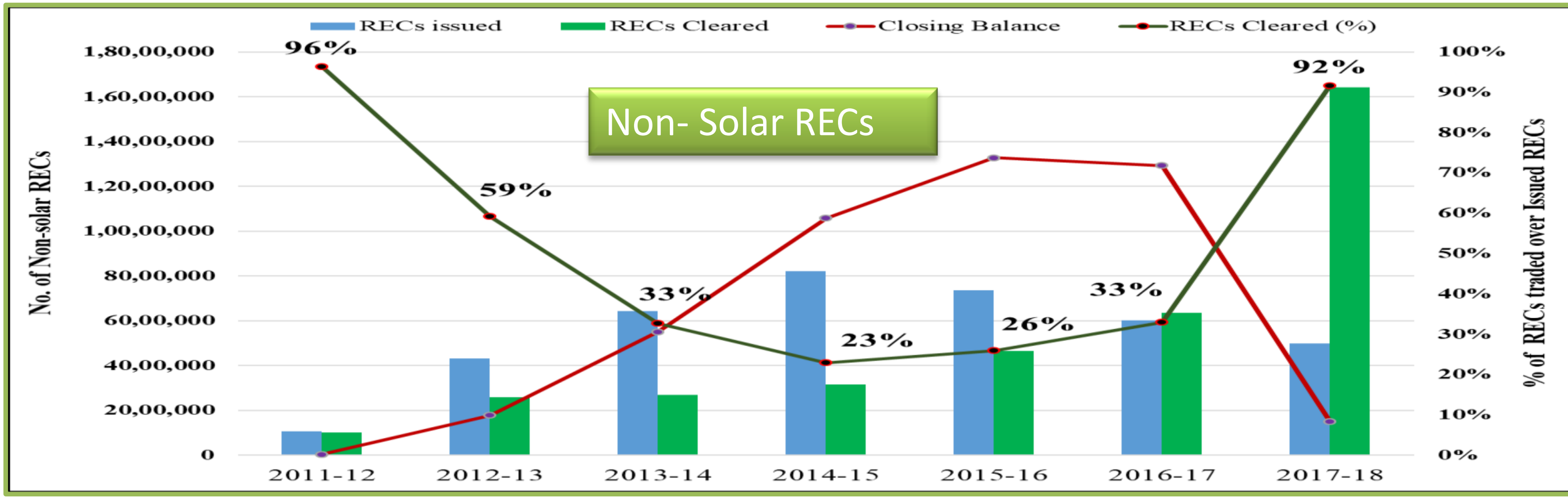
Accreditation						Registration						Breakup of RECs			
Total		Revoked/ Expired		Net		Total		Revoked/ Expired		Net		Issued	Redeemed through		Closing Balance
No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)		PXs	Self Retaintion	
104	1,044	53	518	51	526	93	925	52	524	41	401	8,560,742	8,341,279	138,953	80,510

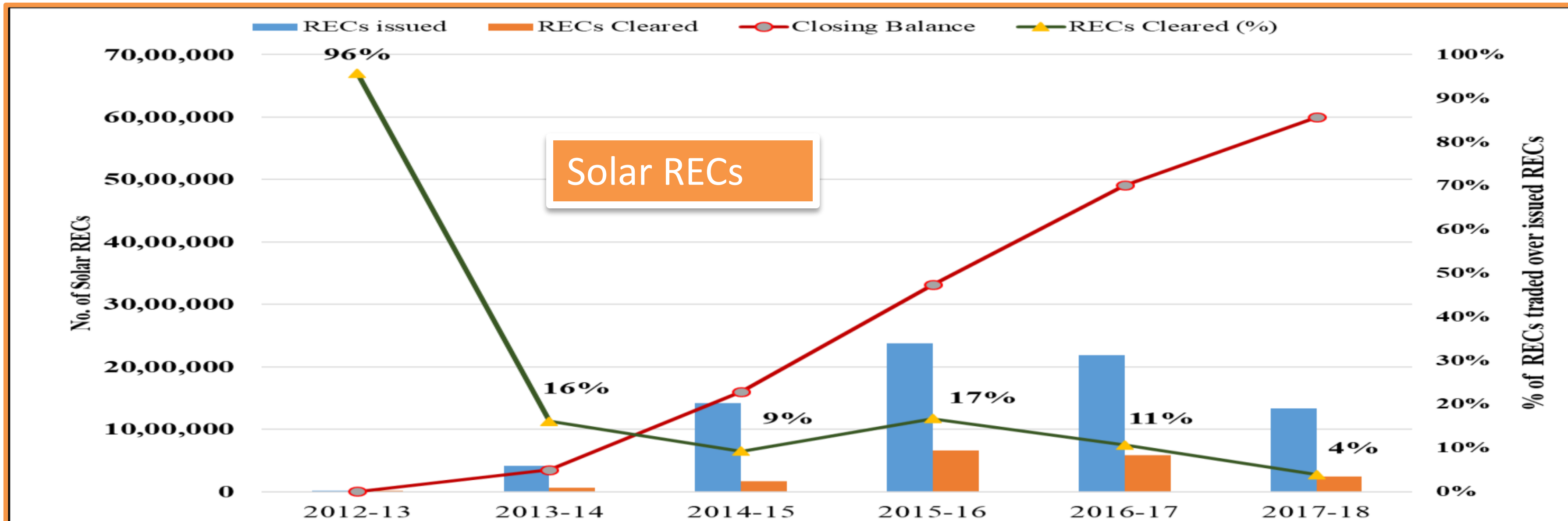
Month-wise issuance of RECs



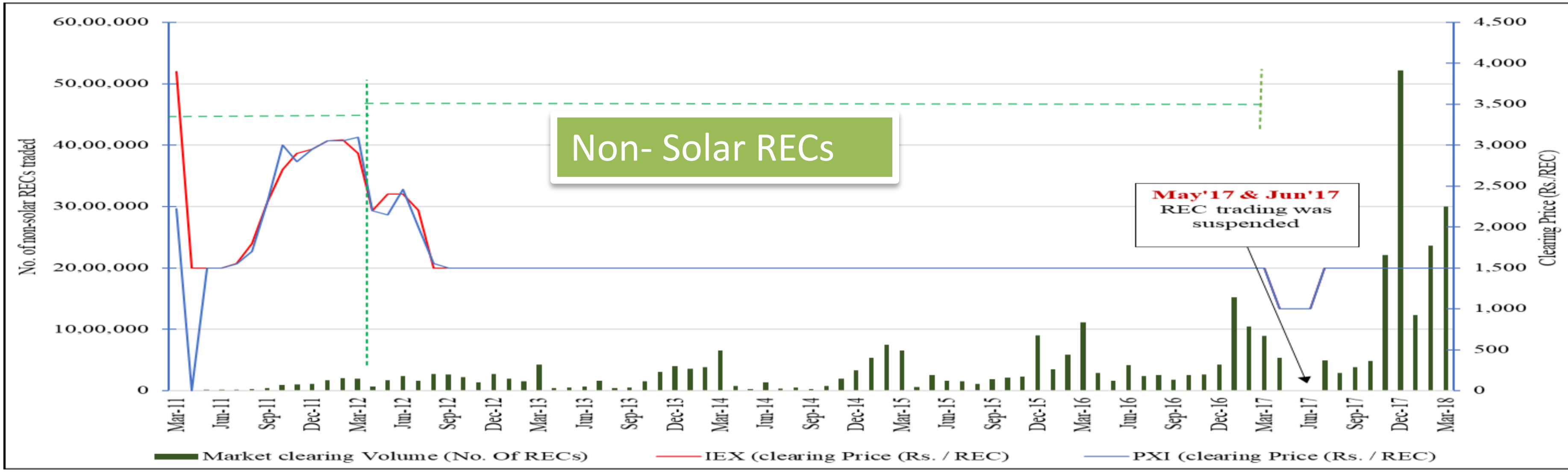


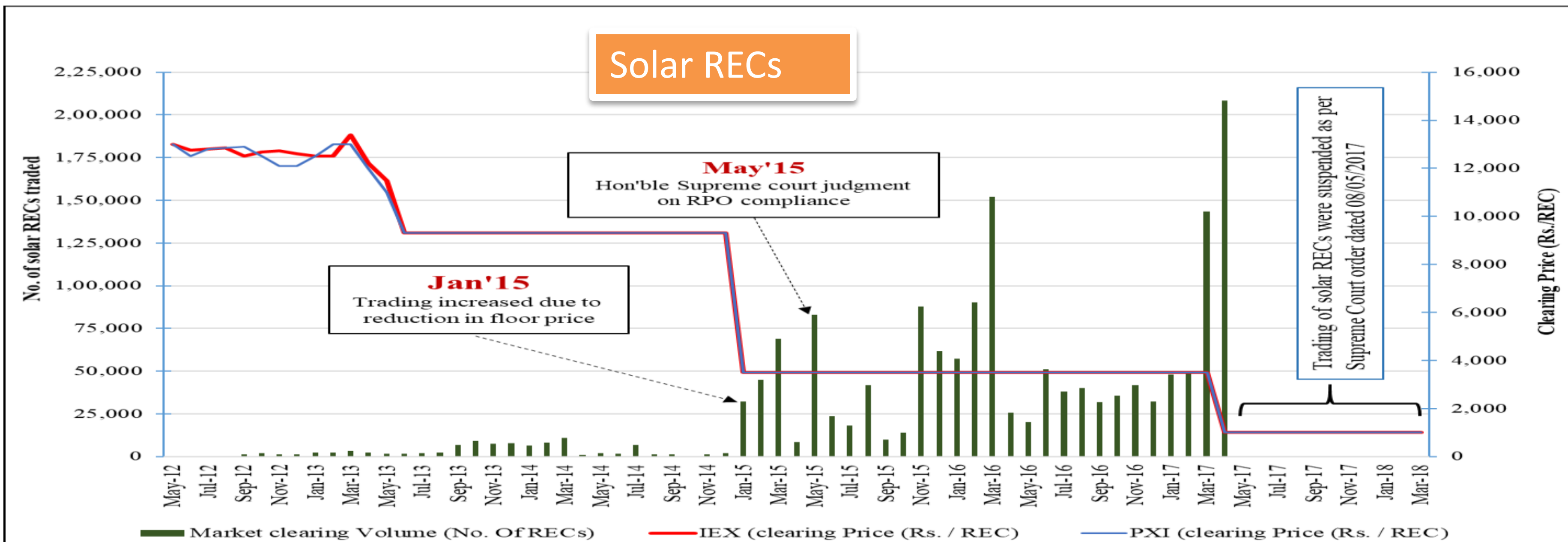
FY-wise % of RECs traded over issued RECs





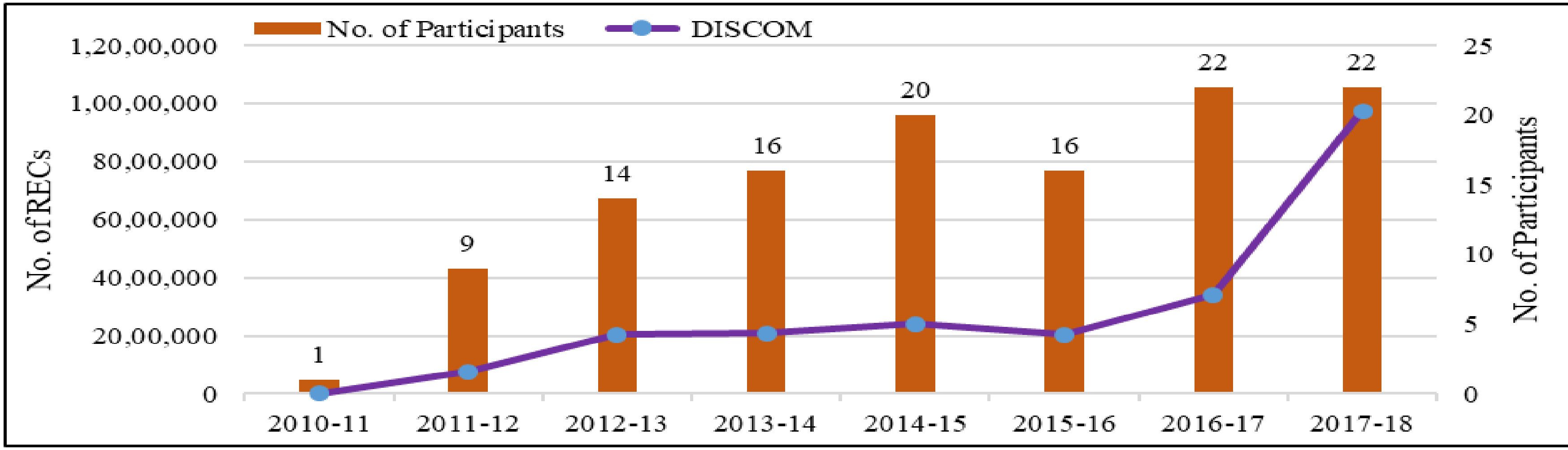
Trading of RECs at Power Exchanges



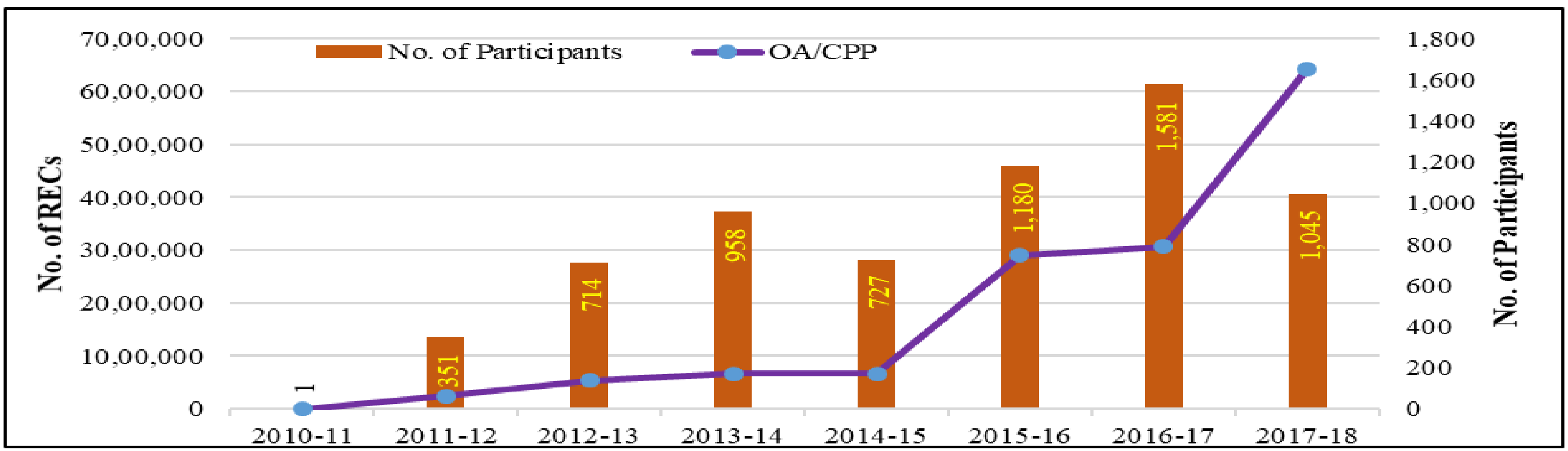


RECs vis a vis market development

RECs purchased by DISCOMs



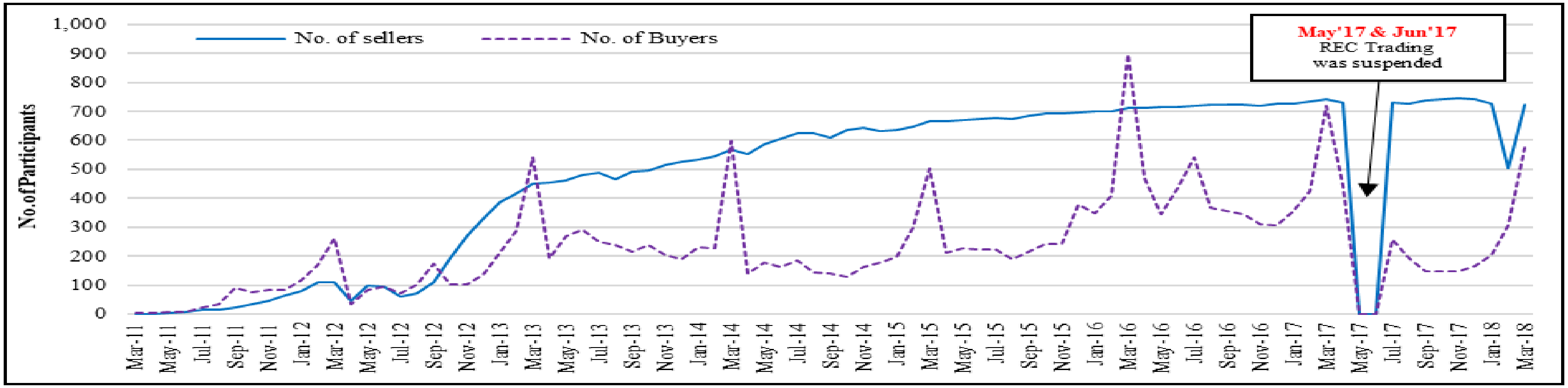
RECs purchased by OA/CPP consumers



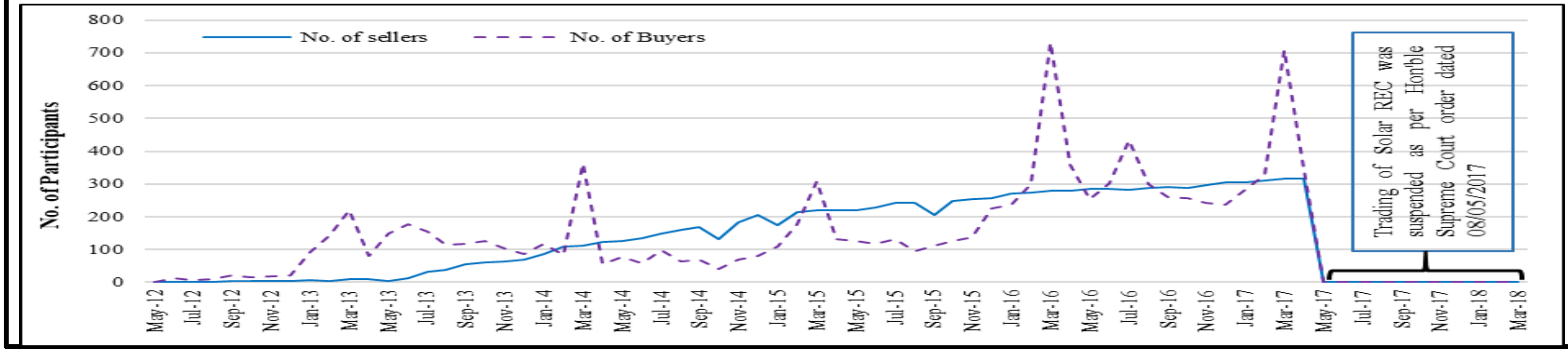
RECs vis a vis market development

Growth in number of buyers and sellers

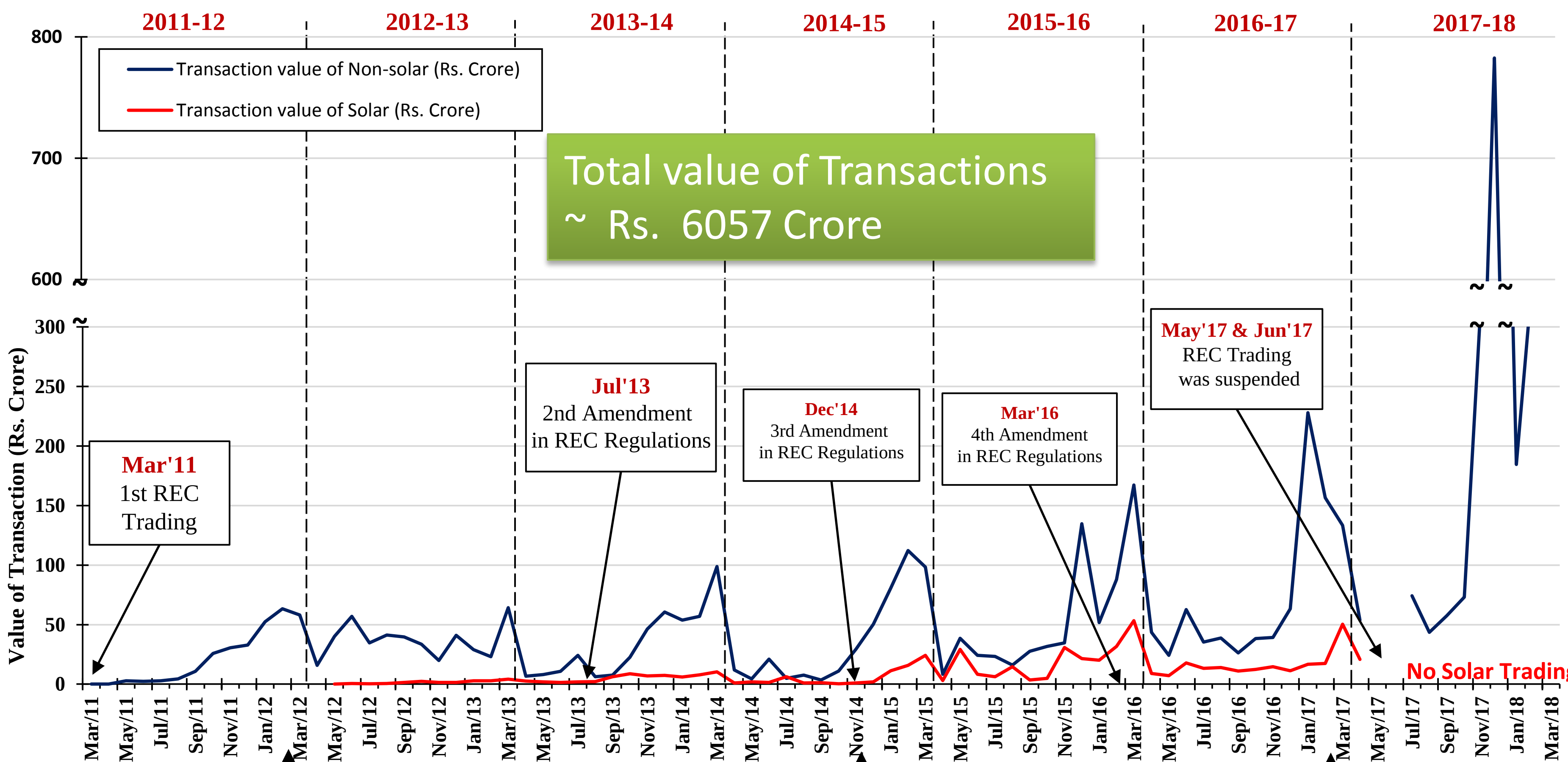
Non-Solar



Solar



Month wise value of transaction of RECs



01.06.2010 - 31.03.2012
Forbearance Price:
Solar: Rs. 17000
Non-solar: Rs. 3900

Floor Price:
Solar: Rs. 12000
Non-solar: Rs. 1500

01.04.2012 - 31.12.2014
Forbearance Price:
Solar: Rs. 13400
Non-solar: Rs. 3300

Floor Price
Solar: Rs. 9300
Non-solar: Rs. 1500

01.01.2015 - 31.03.2017
Forbearance Price:
Solar: Rs. 5800
Non-solar: Rs. 3300

Floor Price
Solar: Rs. 3500
Non-solar: Rs. 1500

w.e.f. 01.04.2017
Forbearance Price
Solar: Rs. 2400
Non-solar: Rs. 3000

Floor Price
Solar: Rs. 1000
Non-solar: Rs. 1000

State/UT-wise analysis

Jharkhand

Type of Buyer	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	Total	% of total REC Purchased
DISCOM	0	75,275	13,866	79,866	167,332	175,990	288,594	800,923	52.5
OA/CPP	50,883	65,992	12,500	25,000	37,000	12,234	521,230	724,839	47.5
Voluntary	5	0	0	0	0	0	0	5	0.0
Total	50,888	141,267	26,366	104,866	204,332	188,224	809,824	1,525,767	100

Gujarat

S. No.	Source	Total Accredited till 31.03.2018		Accreditation Revoked/Expired		Total Registered till 31.03.2018		Registration Revoked/Expired		RECs Issued	RECs Redeemed Through Power Exchanges	RECs Redeemed Through Self Retention	Closing Balance
		No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)				
1	Bio-fuel cogeneration	7	25	1	4	7	25	1	4	258,262	256,978	0	1,284
2	Biomass	3	15	2	11	3	15	3	15	75,542	75,539	0	3
3	Solar PV	8	17	3	5	6	10	2	4	16,783	863	0	15,920
4	Wind	53	443	21	216	47	389	15	162	3,149,894	2,955,308	182,691	11,895
	Total	71	500	27	237	63	439	21	185	3,500,481	3,288,688	182,691	29,102

Type of Buyer	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	Total	% of total REC Purchased
DISCOM	423,422	271,321	369,715	777,065	601,030	317,004	207,153	2,966,710	60.1
OA/CPP	578	0	1,190	1,072	416,362	808,769	738,245	1,966,216	39.9
Voluntary	0	0	0	0	0	0	0	0	0.0
Total	424,000	271,321	370,905	778,137	1,017,392	1,125,773	945,398	4,932,926	100

*Include 274 nos. of RECs purchased by DISCOM in FY 2010-11

Weblinks

- www.powermin.nic.in
- www.mnre.gov.in
- www.cercind.gov.in
- www.forumofregulators.gov.in
- www.recregistryindia.nic.in
- www.iexindia.com
- www.powerexindia.com

- http://www.aperc.gov.in
- http://www.apserc.nic.in/
- http://aerc.nic.in/
- https://berc.co.in/
- http://www.cserc.gov.in/
- http://www.derc.gov.in/
- http://www.gercin.org/
- https://herc.gov.in/
- http://hperc.org/
- http://www.jkserc.nic.in/
- http://jserc.org/
- https://www.karnataka.gov.in/
- http://www.erckerala.org/
- http://www.mperc.nic.in/
- http://www.mercindia.org.in/

- http://www.mserc.gov.in/
- http://www.nerc.org.in/
- http://www.orierc.org/
- http://pserc.nic.in/
- http://rerc.rajasthan.gov.in/
- http://www.sserc.in/
- http://www.tnerc.gov.in/
- http://www.tserc.gov.in/
- http://terc.nic.in/
- http://www.uperc.org/
- http://www.uerc.gov.in/
- http://www.wberc.net/
- https://www.jerc.mizoram.gov.in/
- http://www.jercuts.gov.in/


THANK YOU

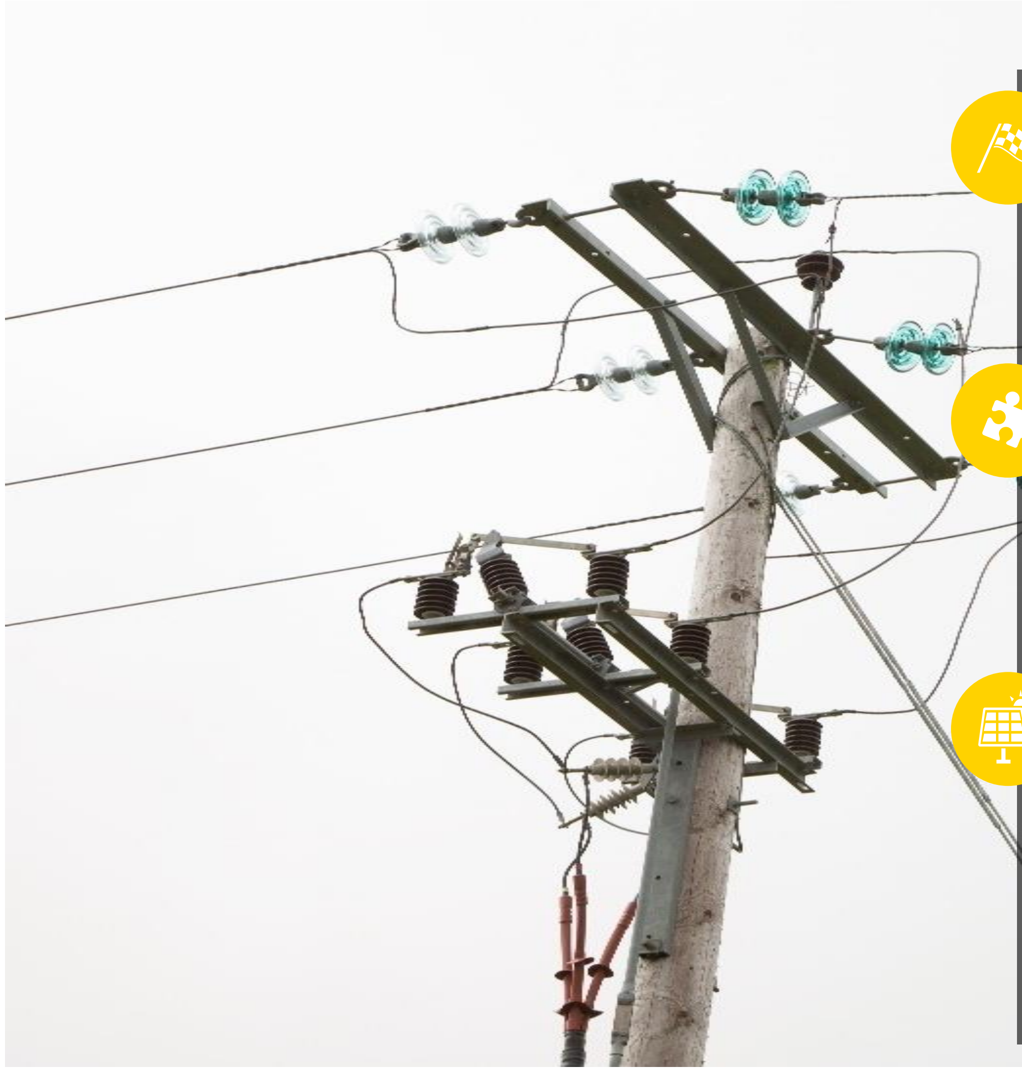
Annexure-II A

Developing Comprehensive Metering Regulations & Accounting Framework for Grid Connected Rooftop Solar Deployment in India

Presentation to Forum of Regulators

24th August, 2018

Contents



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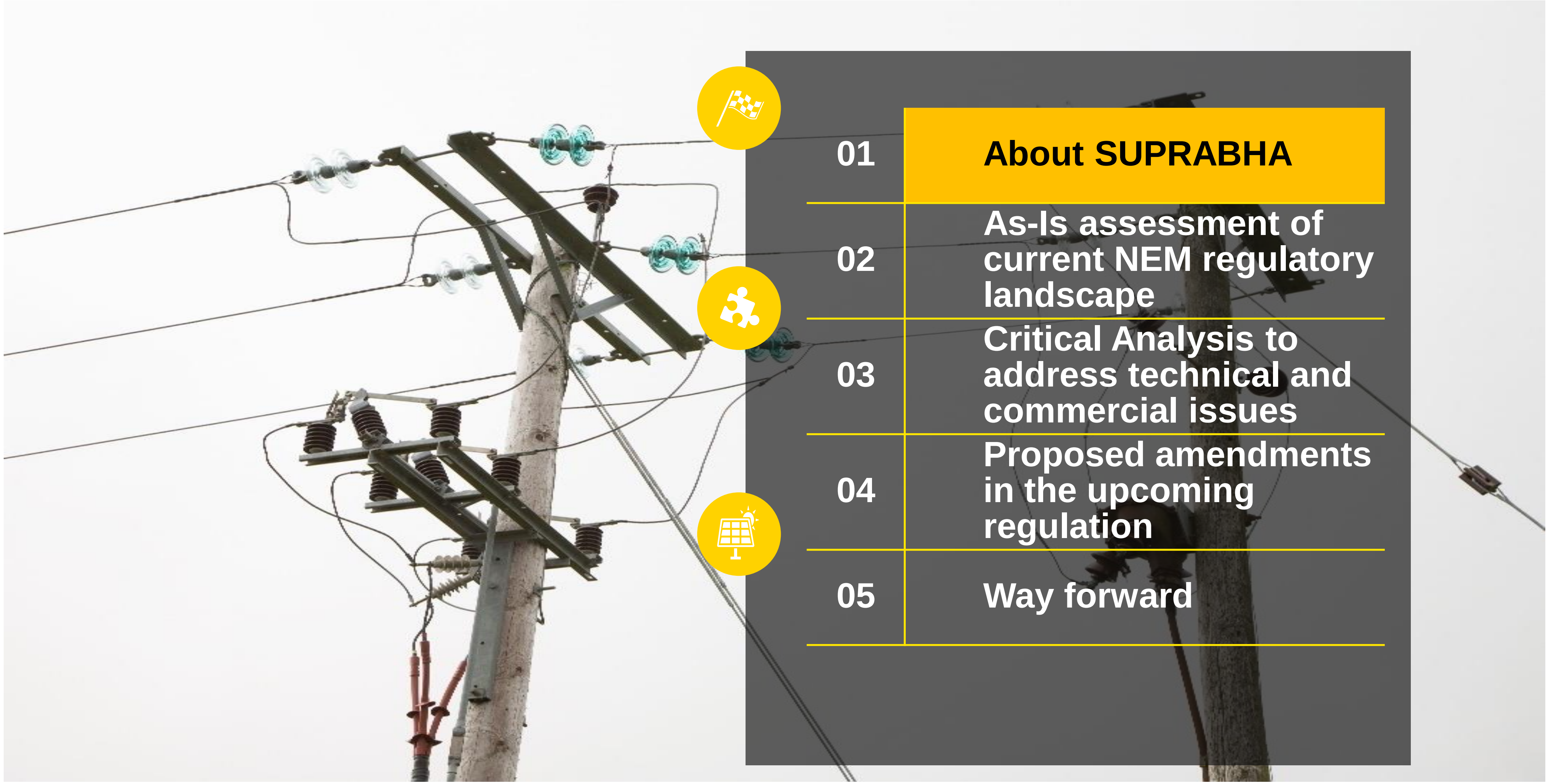


The World Bank – SBI Grid Connected Rooftop Solar Photo Voltaic Technical Assistance Program

SUPRABHA

SUSTAINABLE PARTNERSHIP FOR
ROOFTOP SOLAR ACCELERATION IN BHARAT

SUPRABHA Rooftop Solar TA Program

Funding Body	Implementing Agency	Installation target
WORLD BANK GROUP	SBI	600 MW GRPV

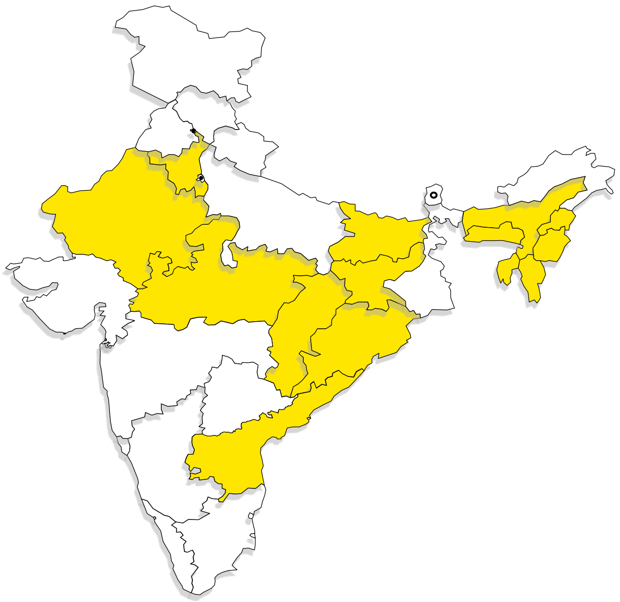
Long Term Concessional Loan: USD 625 Million
https://www.sbi.co.in/webfiles/uploads/files/SBI_WORLD_BANK.pdf

Technical Assistance : USD 13 Million
www.suprabha.org

Stakeholders

- Residential Consumers
- Regulators & Distribution Companies
- Urban Local Bodies
- C&I Consumers
- Financial Institutions
- Entrepreneurs

Coverage : 17 Indian states



- Jharkhand
- Bihar
- Orissa
- Chhattisgarh
- Rajasthan
- Haryana
- Madhya Pradesh
- Delhi
- Chandigarh
- Assam
- Nagaland
- Manipur
- Mizoram
- Tripura
- Meghalaya
- Sikkim
- Andhra Pradesh

Interventions:

1. Policy & Regulatory
2. Capacity Building
3. SSN Knowledge Exchange
4. Media & Outreach
5. Process Streamlining
6. Demand Aggregation

SUPRABHA

Structure of the SUPRABHA TA program

Adoption of Synergetic design principles to gain impactful outcomes

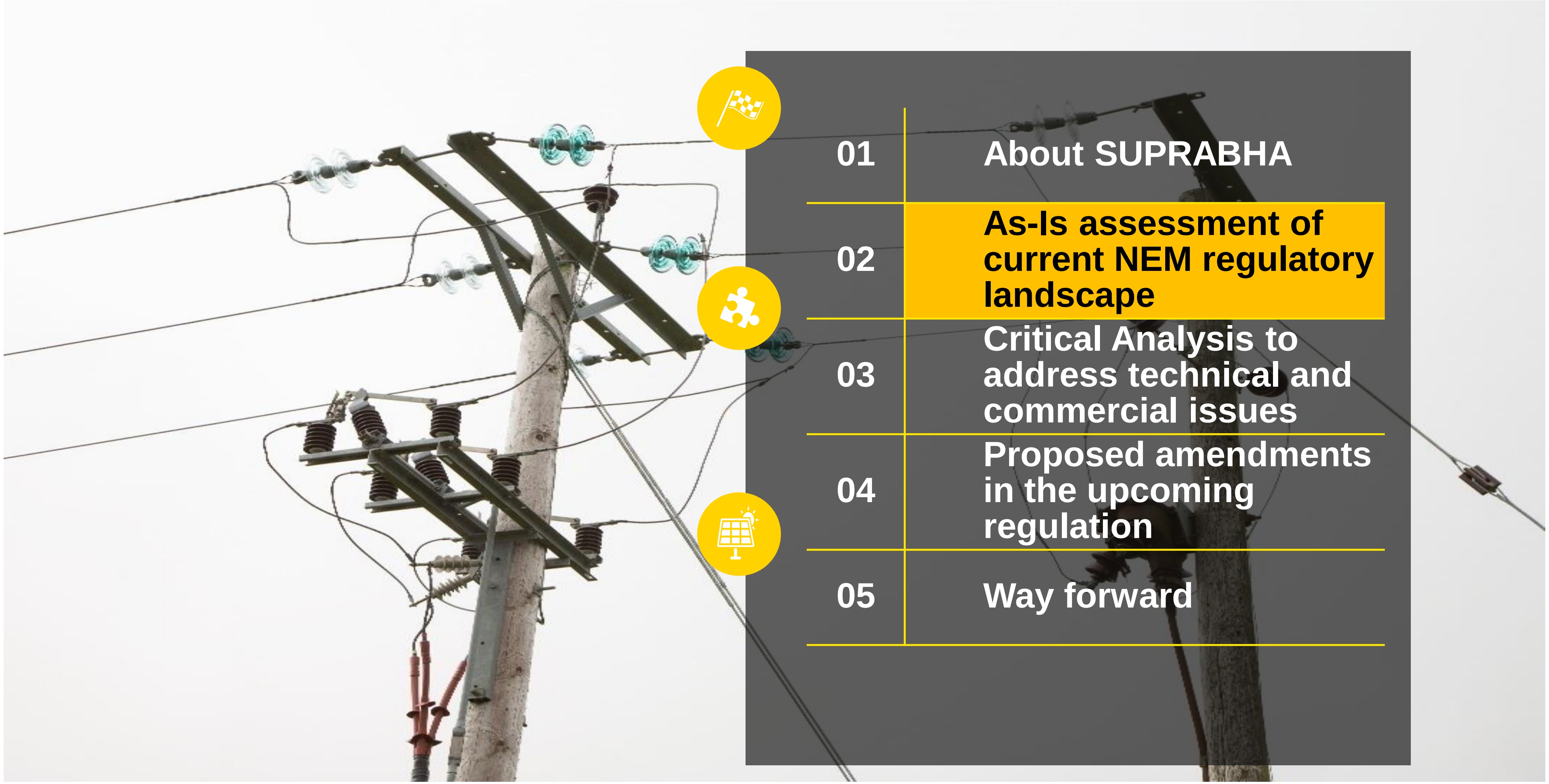
Capturing Sectoral issues → Deliverables outlined in TA program → Development of activities / scope

Work Packages for Execution

1. Mobilization
2. Visioning Workshop and development of Project monitoring framework – Dashboard
3. Policy & Regulatory
4. Capacity Building
5. SSN Knowledge Exchange
6. Media & Outreach
7. Process Streamlining
8. Demand Aggregation

PART 1 | PART 2

Contents



Net Metering Regulation, 2013 - Highlights

Interconnection arrangements	▶ Respective Commissions to decide the target capacity ▶ No limit on individual capacity installed based on sanctioned load ▶ Interconnection limit : up to **15% of the peak capacity** of the distribution transformer (DT) ▶ Maximum installed capacity possible**: 1 MW**
Energy accounting & commercial arrangements	▶ Promotes self consumption ▶ **No payment/credit Carry forward to consumer** for the excess electricity generated ▶ Settlement period : Financial Year ▶ ToD consumers: Excess generation treated as if occurred during off-peak hours

SUPRABHA

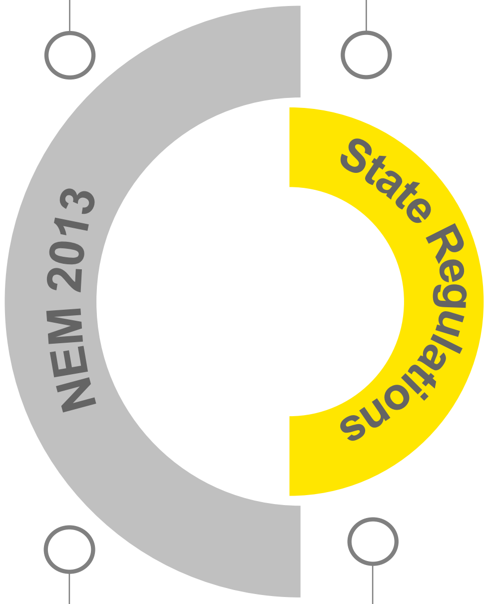
Net Metering Regulation, 2013 - Highlights

Metering	▶ MRI type meters ▶ Accuracy class – Net meter (1.0 or better), Solar meter (0.2) ▶ Check meter mandatory for above 20 KW GRPV systems
Other regulatory provisions	▶ RPO: Benefit to DISCOM in case of non-obligated consumer ▶ Promotes CAPEX/ RESCO Model only; No scope for Utility Centric model ▶ Provision for setting higher capacity through alternative mechanisms

Need for review:

- **Changing landscape** as higher capacities coming-up in India, available advanced metering and communication capabilities
- **Enabling regulatory framework** to support ambitious government targets and support relevant policies
- **Introducing new business models** to Improve GRPV penetration; based on international experience
- **Need of remunerative commercial arrangement** to increase consumer participation

Adoption of NEM 2013 by States: Differences in state adoption in few key features



NEM 2013

Capacity Cap

No cap in terms of sanctioned load

15% of in terms of peak DT capacity

Maximum Capacity

1 MW under net metering

Commercial Settlement

No payment or carry forward in case excess generation

State Regulations

Capacity Cap

40% to 100% in terms of sanctioned load

15% to 80% in terms of peak DT capacity

Maximum Capacity

1 MW and 500 KW under net metering

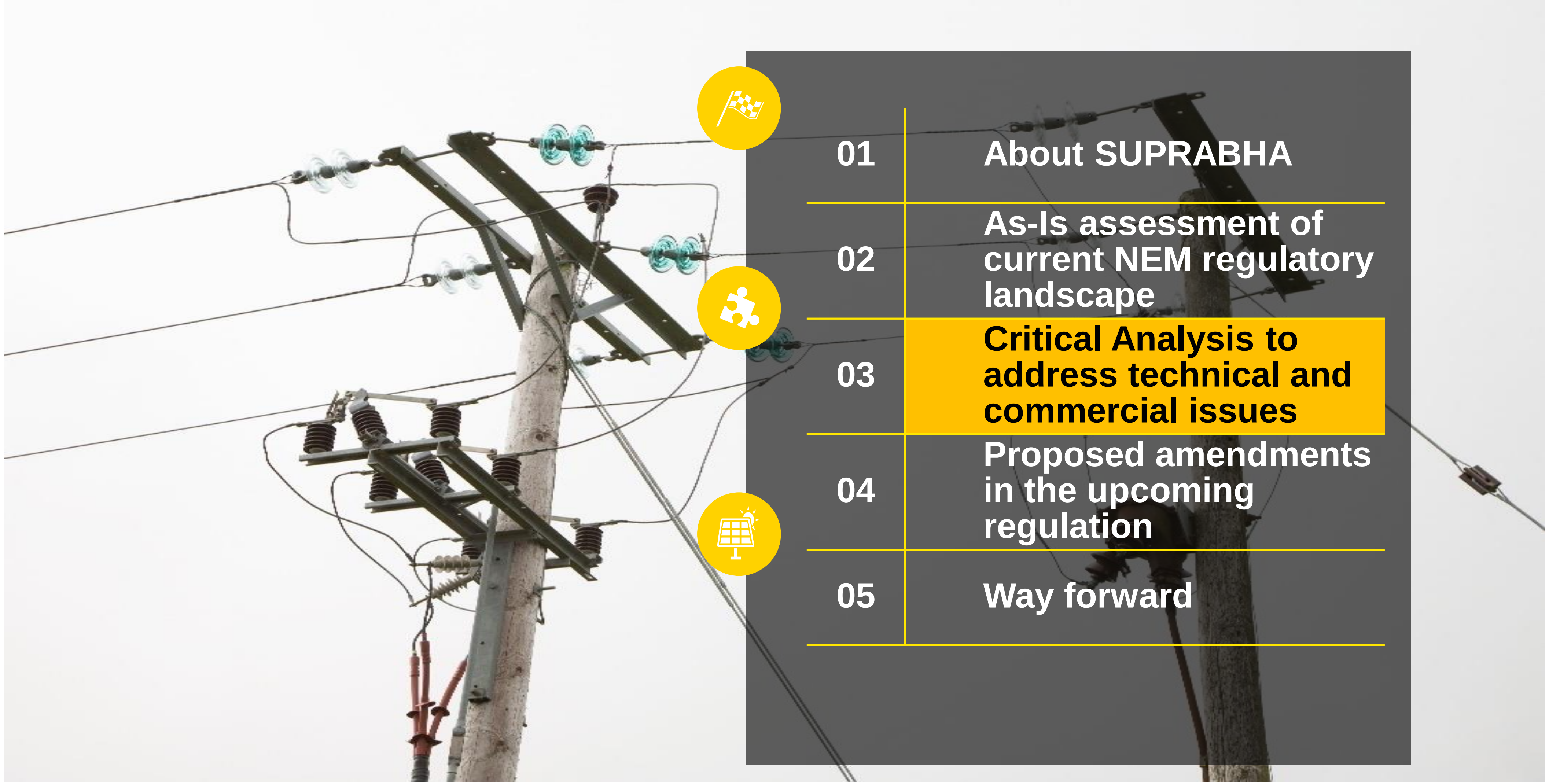
Commercial Settlement

Some states followed NEM 2013, other wise @APPC or FiT

As Is Assessment: Identification of key issues

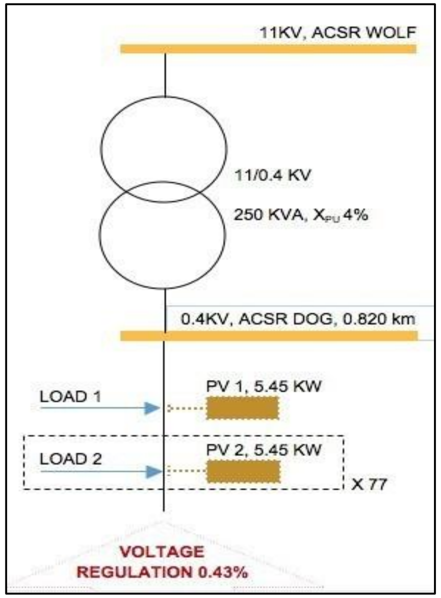
Sr. No.	Issues identified	Type
T-1	Need for relaxing the maximum individual capacity that can be deployed based on sanctioned load	Technical
T-2	Need for clarifying the interconnection limits on GRPV capacities connected to DT	Technical
T-3	Need for provisioning for real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems	Technical, grid stability & safety
C-1	Need for accommodating newer business models available to consumer and developers, limited scope to DISCOMs in present scenario	Commercial
C-2	Present PPA or connection agreement need additional aspects related to change in ownership and flexibility in existing PPA/connection agreement	Commercial
C-3	Need for compensating for excess generation in present energy accounting and commercial settlement principles	Commercial
O-1	Definition of premises and Solar roof-top PV systems needs review owning to future possibility of different scenarios	General definition & others
O-2	Metering and communication requirements needs review to provide greater visibility on solar generation to DISCOMs and system operations	Communication, metering & safety

Contents



Critical Analysis to address technical issues

- Technical study conducted to assess maximum aggregated capacity of solar PV rooftop plants that can be connected to grid without impacting system operation within existing control and infrastructure configuration
- Impact assessment considering two key limiting parameters
  - Feeder/Grid asset thermal capacity
  - Over-voltage at point of interconnection
- Simulation model to conduct maximum capacity under different scenarios:
  - Different voltage level (0.4KV, 11 KV and 33KV)
  - Different DT capacity
  - Different loading conditions (rural, urban)



- If the installed PV capacity is limited to 100% of the sanctioned load, no limiting factors apply to the distribution element for 0 – 100 % DT loading.
- If the installed PV capacity exceeds the sanctioned load, the following will act as limiting factors
  - Thermal capacity of the feeder (in case the loads are equally distributed across the feeder)
  - Voltage rise (in case the PV are concentrated at farther end of the of the feeder)
  - Technically feasible to set up GRPV systems beyond 1 MW

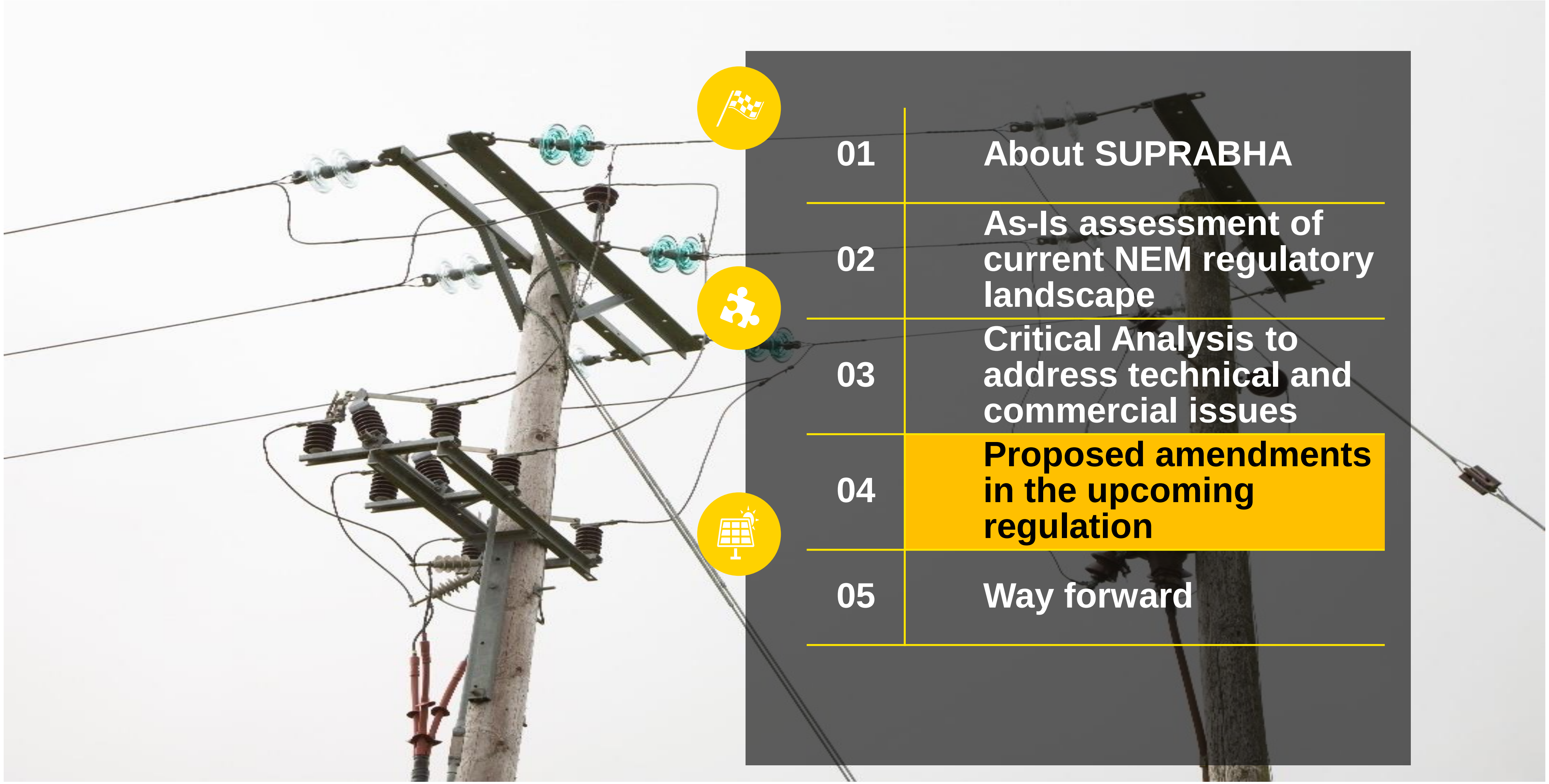
Critical Analysis to address Commercial issues

- Study of business models adopted in leading developed countries in solar rooftop deployment like Germany, USA, Canada and the settlement mechanism adopted
- Selection of business models based on following primary consideration
  - Responsibility of CAPEX
  - Responsibility of OPEX
  - Commercial Settlement
- Additional conditions considered for selection of business models
  - High Demand, Small roof
  - Multiple Beneficiaries
- Total 72 combinations developed and their operational feasibility evaluated

- Proposed Consumer centric and Utility centric business models and their respective accounting and settlement mechanisms be in the regulation
- Suggested 6 business models
  - Detailed cash flow analysis done for each model suggested
  - Benefit Analysis done for different stakeholders for each model suggested; Utility, Consumer and developer

Selection of Business models → Assumptions: cash flow

Contents



New sections/Concepts proposed in the upcoming regulation

1

New business models

Utilities might act as various type of facilitators such as RESCO, EPC contractor, demand aggregator, resulting in promotion of innovative business models

2

Operational improvements

Consumer application to final system commissioning – the entire consumer interface with DISCOMs will be online through interactive portals

3

Metering Arrangements

Net Metering , Net billing for Prosumer based system and Independent DRE system

4

Government structure and institutional framework

DRE cell at DISCOMs, formation of DRE advisory committee , clarity in their role and responsibilities

5

Promotion of distributed generation

Provisions related to RPO targets, incentive to DISCOMs to procure power from distributed generation

Amendments proposed for T-1: Need for relaxing the maximum individual capacity that can be deployed based on sanctioned load

Proposed changes in the model regulation:

- For Prosumer owned DRE System (PDRES) - Individual project capacity not to exceed the sanctioned load/contract demand of the prosumer
- For Independent DRE System (IDRES) - Individual project capacity will be evaluated based on technical constraints
- Minimum system sizes for PDRES net metering & PDRES net billing will be 1 kW & 10 kW respectively where as minimum size for IDRES will be 50 kW

Amendments proposed for T2: Need for clarifying the interconnection limits on GRPV capacities connected to DT

Proposed change in the model regulation:

- The cumulative capacity of distribution renewable energy systems allowed to be interconnected with the distribution network (feeder/ distribution transformer, owned by distribution licensee) shall not exceed 100% of the feeder and / or distribution transformer capacity, as applicable.

Amendments proposed for T-3: Need for provisioning for real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems

- For stable grid operation, visibility on solar generation (at least beyond certain capacity) required in case of large penetration of GRPV systems
- In future, the GRPV systems must also respond to system operation requirements

Proposed change in the model regulation:

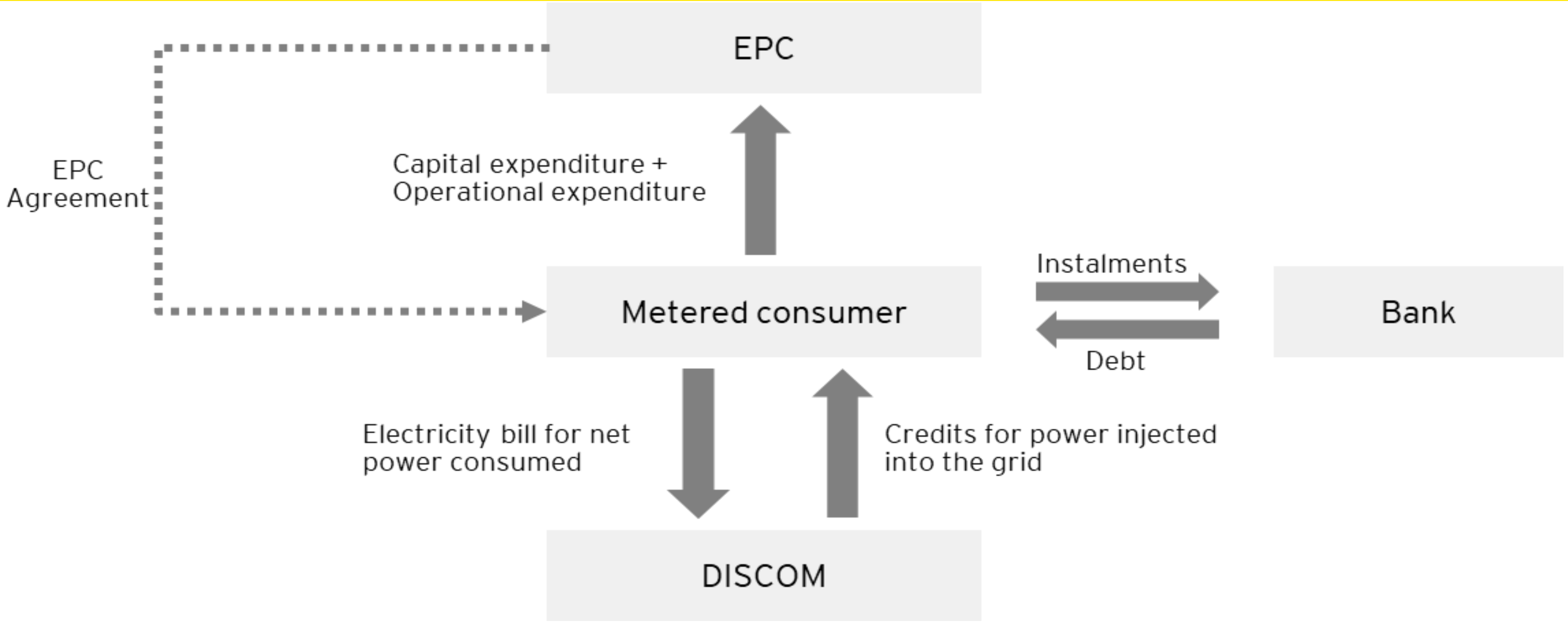
- All meters shall have Advanced Metering Infrastructure (AMI) facility with RS 485 (or higher) communication port to connect future grid digitalization

Amendments proposed for C-1: Need for provisions to accommodate business models available to consumer and developers, limited scope to DISCOMs in present scenario

Proposed changes in the model regulation:

- The distribution licensee may explore appropriate utility driven business models such as demand aggregation, distribution licensee as a RESCO or EPC, etc. to promote installations of distributed renewable energy in its area of supply.
- “Independent Distributed Renewable Energy System” or “IDRES” means a distributed renewable energy system set up by any person and is connected to the distribution licensee network and sells electricity to distribution licensee under Power Purchase Agreement;
- Additional definitions added like “ Prosumer” and “RESCO” to adopt different ownership options

1. Consumer – owned model (Cap – Ex)



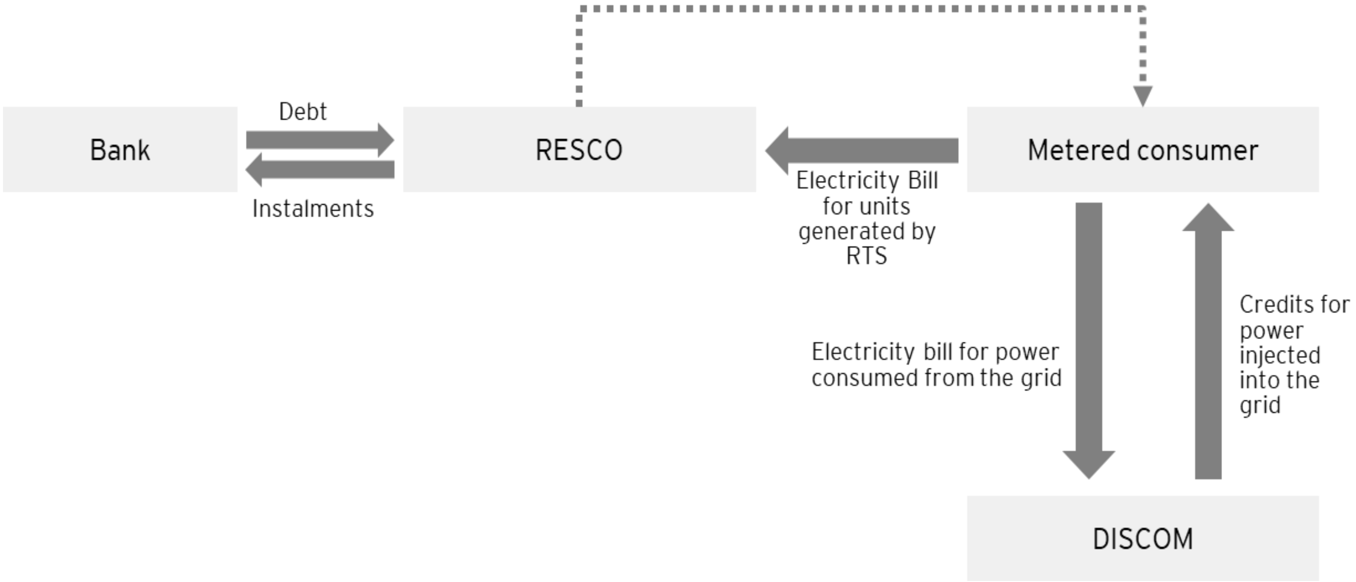
Benefits

- Consumer completely owns the asset (rooftop solar system)

Drawbacks

- Consumer faces an upfront capital expenditure
- Operation and maintenance expenditure

2. Third-party owned (RESCO) model



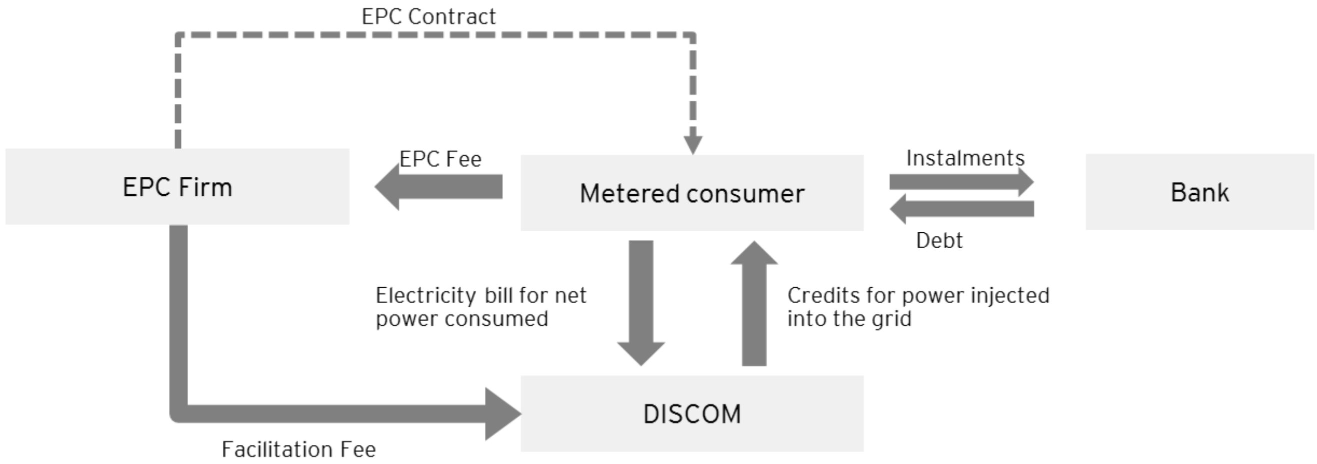
Benefits

- No upfront capital expenditure for the consumer
- Operation and maintenance is performed by the RESCO

Drawbacks

- Payment default risk exists for the RESCO

3. Consumer Owned (utility only aggregates)



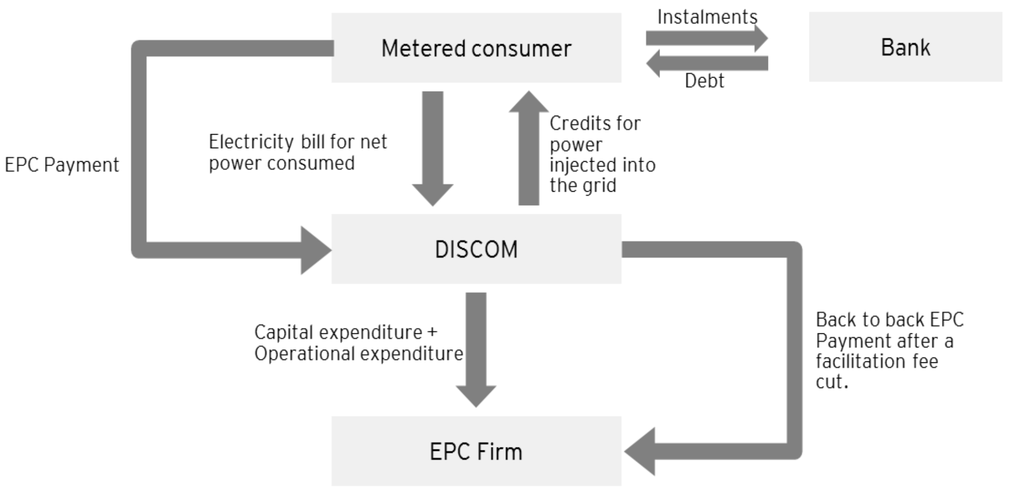
Benefits

- Single-window portal for the consumer for installation of rooftop solar
- Reduced EPC costs due to economies of scale and competition amongst EPC providers
- Streamlined interconnection process due to continued involvement of the utility through the installation stage
- Verified quality of the installed systems due to setting up of procurement standards
- Reduced financing costs due to lower risks

Drawbacks

- Upfront capital expenditure is required from the consumer
- Payment default risk for the lender

4. Consumer Owned (Utility aggregates and acts as EPC)



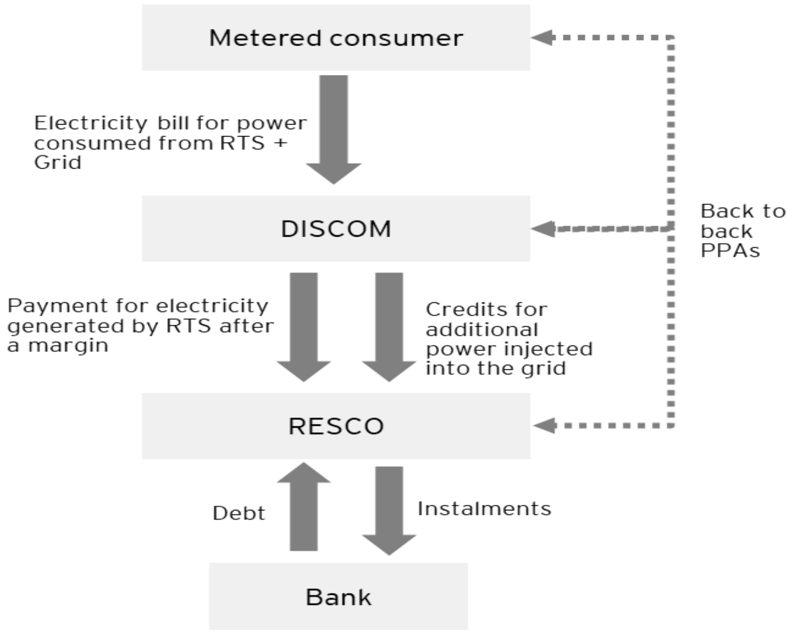
Benefits

- Single-window portal for the consumer for installation of rooftop solar
- Improved service experience for the consumer due to project management by the utility
- Reduced EPC costs due to economies of scale and competition amongst EPC providers
- Streamlined interconnection process due to continued involvement of the utility through the installation stage
- Verified quality of the installed systems due to setting up of procurement standards
- Securitised payments to the EPC providers
- Reduced financing costs due to lower risks

Drawbacks

- Upfront capital expenditure is required from the consumer
- Payment default risk for the lender

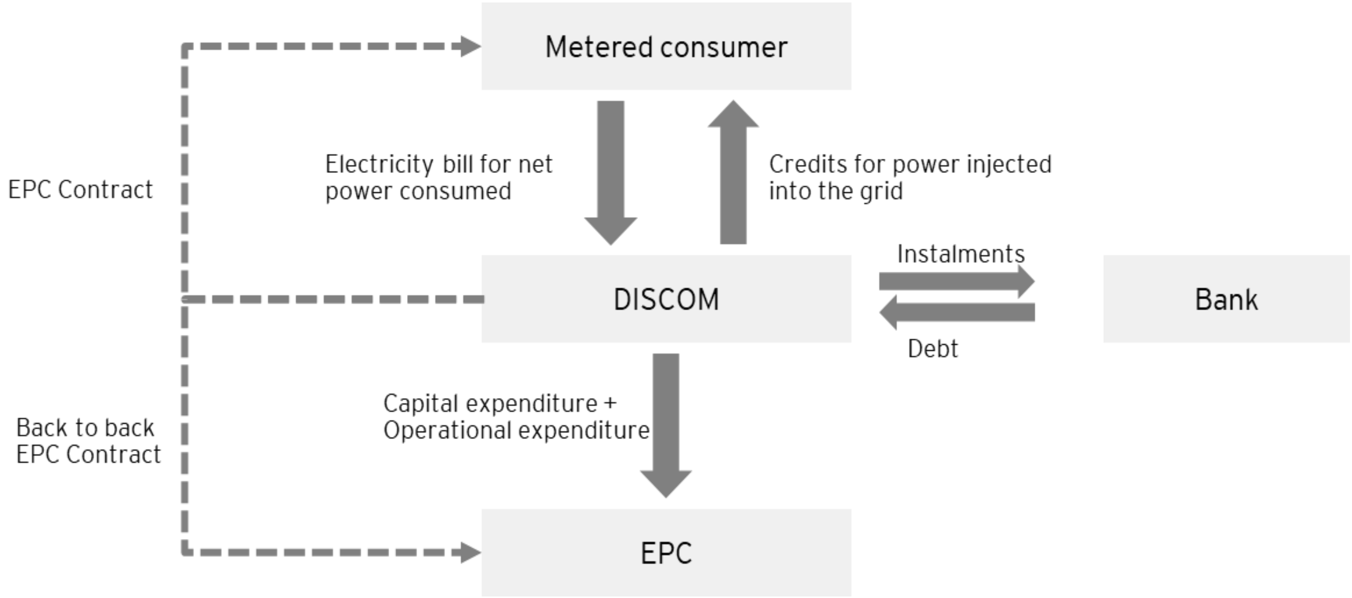
5. Utility aggregates and acts as trader between RESCO and consumer



Benefits

- Single-window portal for the consumer for installation of rooftop solar (including finance).
- Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs.
- Securitised payments to the financiers and the RESCO.
- Reduced financing costs due to lower risks.

6. Utility aggregates and acts as RESCO



Benefits

- Single-window portal for the consumer for installation of rooftop solar (including finance).
- Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs.
- Securitised payments to the financiers and the RESCO.
- Reduced financing costs due to lower risks.

Benefit analysis in case of different business models(1/4)

S. No	Model	Utility	Consumer	Developer
1	Consumer-owned model (Cap-Ex)	Reduced energy sale	EPC fees	Profit on EPC fee received
		Benefits due to RPO, reduced procurement and lower AT&C losses	n*T	
	Overall	Utility revenue decreases. Benefits due to abovementioned factors.	Saves on electricity bill. Gains the asset	Gains revenue as EPC fee
2	Third-party owned (RESCO) model	Reduced energy sale	n(T-T')	EPC fees
		Benefits due to RPO, reduced procurement and lower AT&C losses		n*T'
	Overall	Utility revenue decreases. Benefits due to abovementioned factors.	Saves on electricity bill.	Gains asset and revenue due to sale of service

Legend	
T	Grid tariff
T'	Discovered tariff
m	Total consumption (number of units)
n	Number of units of electricity consumed from the Rooftop Solar System

Benefit analysis in case of different business models(2/4)

S. No	Model	Utility	Consumer	Developer
3	Consumer owned model (utility only aggregates)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC fee received
		Benefits due to RPO, reduced procurement and lower AT&C losses	n*T	Facilitation fees (assuming 2-3% of the total investment)
		Reduced energy sale		
	Overall	Utility loses revenue due to reduced sale, but makes revenue on facilitation fees. Other benefits due to abovementioned factors.	Lower cost of procurement due to economies of scale. CapEx model overall beneficial under the current regulations.	Gains revenue as EPC fee and saves on transaction cost.

Benefit analysis in case of different business models(3/4)

S. No	Model	Utility	Consumer	Developer
4	Consumer Owned (Utility aggregates and acts as EPC)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC Fee (after a margin cut)
		% on back to back EPC agreements	n*T	p% on back to back EPC agreements
		Loss of energy sale due to influx of rooftop solar		Facilitation fees (assuming 2-3% of the total investment)
		Benefits due to RPO, reduced procurement and lower AT&C losses		
	Overall	Utility loses revenue due to reduced sale, but makes revenue on facilitation fee for aggregation and margin on back to back EPC contract. Other benefits due to abovementioned factors.	Lower cost of procurement due to economies of scale. CapEx model overall beneficial under the current regulations.	Gains revenue on EPC. Saves on transaction cost and gains payment security.

Benefit analysis in case of different business models(4/4)

S. No	Model	Utility	Consumer	Developer
5	Third Party owned (Utility aggregates and acts as trader)	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC Fee
		Facilitation fees (assuming 2-3% of the total investment)		Facilitation fees (assuming 2-3% of the total investment)
		% on all units of energy traded		% on all units of energy traded
		Benefits due to RPO, reduced procurement and lower AT&C losses		Revenues from energy sale
	Overall	Utility makes revenues due to energy trading and facilitation fees for aggregation. Other benefits due to abovementioned factors	RESCO model beneficial due to no capital investment. Energy costs reduced.	Revenues due to energy sale. Low transaction costs and lower capital cost due to aggregated demand. Also, gains the asset.
6	Utility aggregates and acts as RESCO	EPC Fee	n(T-T')	
		Revenue from energy sale (y*n)		
		Benefits due to RPO, reduced procurement and lower AT&C losses		
	Overall	Utility makes revenue on energy sale to the consumers. Lower cost of procurement due to economies of scale.	RESCO beneficial due to no capital investment. Energy costs reduced.	Developer plays no role

Amendments proposed for C-2: Present PPAs/connection agreements need additional aspects related to change in ownership (1/2)

- In the wake of newer arrangements, associations (such as RWAs, etc.) may also set up GRPV systems definition of agreement needs to be widened within present legal framework
- As per EA 2003, a "person" shall refer to the eligible consumer, group of eligible consumers or any company or body, corporate or association or body of individuals, whether incorporated or not, or artificial juridical person;

Proposed Change in the model regulation:

- "Agreement" means an agreement entered into by the distribution licensee with the person;

Amendments proposed for C-2: Present PPAs/connection agreements need additional aspects related to change in ownership (1/2)

New definitions proposed in the model regulation:

- “**Independent Distributed Renewable Energy System**” or “IDRES” means a distributed renewable energy system set up by any person and is connected to the distribution licensee network and sells electricity to distribution licensee under Power Purchase Agreement;
- “**Prosumer**” is a person who consumes electricity from the grid and can also inject electricity into the grid using same network from renewable energy system set up on consumer side of the meter.
- “**Renewable Energy Service Company (RESCO)**” means an energy service company which owns a renewable energy system and provides renewable energy to the consumer.

Provided that the distribution licensee may act as a RESCO. However, this business shall be treated as other business of the distribution licensee.

Amendments proposed for C-3: Need for compensating for excess generation in present energy accounting and commercial settlement principles

- Few states allowed compensation, though, at different rates

State	Andhra Pradesh	Assam, Gujarat, Karnataka, Kerala, Madhya Pradesh, New Delhi, Telangana	Bihar, Tamil Nadu	Jharkhand, Uttar Pradesh
Treatment of excess energy in Net Metering	@ACoS	@APPC	@Tariff in force for that particular consumer	@INR 0.50/kWh

Proposed changes in the regulation:

- Excess energy generated by PRDES to be settled at Average Power Purchase Cost for the year in which such excess energy is procured by the distribution license.
- The distribution licensee may undertake procurement of power from IDRES plants under Section 63 of the Act according to the prevailing bidding guidelines

SUPRABHA

Amendments proposed for O-1: Definition of premises and Solar roof-top PV systems needs review owning to future possibility of different scenarios

Proposed changes in the regulation:

- Definition of premises is retained as per the EA 2003
- New definitions of Prosumer Distributed Renewable Energy System (PDRES) and Independent Distributed Renewable Energy System (IDRES)
- Individual capacity restricted based on sanctioned load for PDRES system
- Individual project capacity to be evaluated based on technical constraints for IDRES system

Amendments proposed for O-2: Metering & communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

Aspects	Proposed Dispensation	Remarks
Metering	• Meters to have AMI facility (RS 485 or higher communication port	• Required to monitor generation • Monitoring and reporting framework to be part of the model Regulations
Solar Generation meter	• Mandatory for all the systems	• RPO accounting for DISCOMs
Cost of Meters	• To be borne by consumer	• N.A.
New Consumer applying both electricity connection and DRE system	• Allowed	• N.A.

Proposed Structure of the new regulation(1/2)

Part — A

Preliminary

- Short title, and commencement
- Definition and interpretations
- Scope and applicability
- Control Period
- Web based application processing system
- Monitoring and reporting framework

Part — B

Renewable Purchase Obligation

- General Principles

Part — C

Technical Standards and Safety, Metering Infrastructure

- Interconnection with the grid: Technical standards and safety
- Metering Infrastructure

Part — D

Net Metering and Net Billing Arrangement

- Prosumer and project capacity
- Net Metering Arrangement
- Net Billing Arrangement
- Role of the Distribution Licensee
- Hosting Capacity:
- Interconnection Point
- Application Process and Procedure
- Energy Accounting – Net Metering/ Net Billing

Proposed Structure of the new regulation(2/2)

Part — E

Independent Distributed Renewable Energy Systems

- Eligibility and project capacity
- Role of the Distribution Licensee
- Interconnection Point

Part — F

Governance Structure, institutional framework, roles and responsibilities

- Roles of Stakeholders
- DRE Advisory Committee
- Distributed Renewable Energy Cell

Part — G

Miscellaneous

- Penalty or Compensation
- Power to give directions
- Power to relax
- Power to amend
- Power to Remove Difficulties
- Repeal and Savings

Salient Features of Net Metering ….. (1/2)

- The prosumer may **set up distributed renewable energy system** to **offset the prosumer's electricity consumption from the distribution licensee**.
- The **distribution licensee shall** procure **any excess energy generated by PDRES at Average Power Purchase Cost for the year** in which such excess energy is procured by the distribution licensee.
- In case, the **electricity injected by the renewable energy system exceeds the electricity consumed** during the billing period, such **excess injected electricity shall be carried forward to the next billing period** as excess electricity and may be utilized in the following billing periods but within the same settlement period;
- In case, the **electricity supplied by the distribution licensee** during any billing period **exceeds the electricity injected in the grid by the PDRES,** the **distribution licensee shall raise bill for the net electricity** consumption after taking into account any excess electricity carried forward from the previous billing period;

PDRES: Prosumer Distributed Renewable Energy System

Salient Features of Net Metering ….. (2/2)

- In case the prosumer is under the **ambit of Time of Day Tariff**, following process shall be followed:
  - **Electricity consumption in any time block** (e.g., peak hours, off-peak hours, etc.) shall be **first compensated with the electricity generation** in the **same time block**.
  - Any **excess generation over consumption** in any time block in a billing cycle shall be accounted as if the excess generation occurred during immediately lower tariff time block. This process will continue till all consumption in lower tariff blocks is set off against PDRES generation.
  - Any excess generation after setting off consumption in lower tariff time blocks would be carried forward to the next billing cycle.
- Regardless of availability of excess electricity with the prosumer during any billing period, the consumer will continue to pay all other charges such as fixed/demand charges, Government levy, etc.
- The PDRES shall be exempted from all wheeling, cross subsidy, transmission and distribution, and banking charges and surcharges.

PDRES: Prosumer Distributed Renewable Energy System

Salient Features of Net Billing Arrangement ….. (1/2)

- The prosumer may **set up distributed renewable energy system to offset the prosumer's electricity purchase** bill from the distribution licensee.
- Net billing is the arrangement where DRE Plant is:
  - Installed to serve a specific consumer,
  - Connected on utility side on the consumer meter,
  - Selling power to distribution licensee under Power Purchase Agreement,
  - Entire power is consumed by the consumer
- The distribution licensee **shall enter into Power Purchase Agreement** at **tariff to be determined by the Commission.**
- **Entire quantum of electricity** generated by the DRE plant shall be procured by the distribution licensee.
- The distribution licensee shall enter into **Power Sale Agreement with the consumer** for sale of entire quantum of power generated by the relevant DRE plant.

PDRES: Prosumer Distributed Renewable Energy System

Salient Features of Net Billing Arrangement ….. (2/2)

- Rate of **sell of power to the consumer** shall be the same rate as **determined by the Commission for procurement of power from DRE Plant**.
- The **distribution licensee** shall **give credit to the consumer by billing the consumer at the tariff** determined by the Commission.

Energy Bill of Consumer =

$$\text{Fixed charges + other applicable charges and levies} + (E_{DL} * T_{RST}) - (E_{RE} * T_{PSA}) - \text{Billing}_{Credit}$$

Where:

- E_{RE} means the energy units recorded for the billing period by the DRE Plant's generation meter;
- T_{PSA} means the energy charges as per the energy sale agreement signed between the consumer and distribution licensee;
- E_{DL} means the energy units supplied by the distribution licensee over and above the E_{RE} for the billing period;
- T_{RST} means the applicable retail supply tariff of the concerned consumer category as per the retail supply Tariff Order of the Commission;
- Billing credit is the amount by which value of DRE generation in a particular month is more than value of all other components of consumer bill

- In case, ($E_{RE} * T_{PSA}$) is more than (Fixed charges + other applicable charges and levies + ($E_{DL} * T_{RST}$)), utility shall give credit of amount equal to difference (Billing Credit) and the same shall be carried forward to next billing cycle.

Contents

Way-forward

- Soliciting comments from FoR on the gaps identified
- Solicit comments from FoR on draft regulation
- Incorporation of FoR comments on the draft regulation
- Release of final model regulation by FoR

Thank you

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A few business model options for uptake of rooftop solar have been developed

Primary considerations based on three parameters

- Ownership – the Party which incurs capital expenditure –
  - 3 options: Utility/Consumer/RESCO
- Operational Expenditure Responsibility – the Party with incurs operation expenditure
  - – 3 options: Utility/Consumer/RESCO
- Settlement – the Party with which settlement is done –
  - 2 options: Utility/RESCO

Two more conditions

- 'High Demand, Small Roof' – One or more facility with higher load and non-availability of rooftop space or, one or more facility with lower load and availability of ample rooftop space
- 'Multiple Beneficiaries' – multiple beneficiaries of the same rooftop solar plant

A total of 3x3x2x2x2 = 72 combinations

Of the 72 combinations, the following six were shortlisted based on operational feasibility

- **Business models shortlisted**
  1. Consumer Owned (Cap-Ex model).
  2. Third Party Owned (RESCO Model).
  3. Third Party Owned (Utility aggregates acts as trader)
  4. Utility aggregates and acts as RESCO

- **Additional identified business models**
  1. Consumer Owned model (utility only aggregates)
  2. Consumer Owned (Utility aggregates and acts as EPC)

Assumptions for cash flow analysis

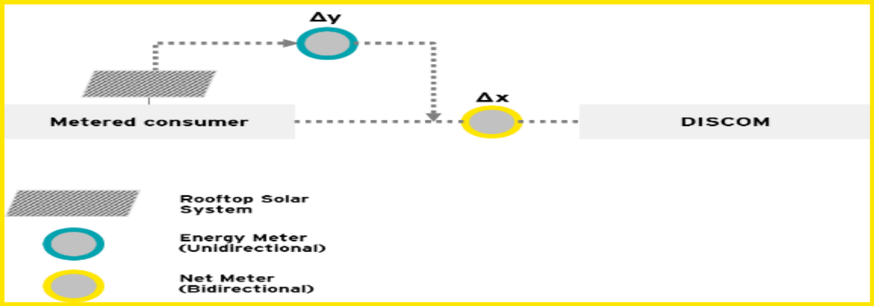
- **Business as usual (hereinafter referred to as BAU)**
  - Assumptions
  - No rooftop solar installation
  - Total consumption in the billing period – 200 kWh
  - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000
- **Rooftop solar system installed**
  - System Capacity – 1 kW
  - Number of units generated per day – 5 kWh
  - Settlement period – 30 days
  - Total consumption in the settlement period – 200 kWh
  - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
  - Grid tariff – 10 INR / kWh
  - PSA tariff – 8 INR / kWh
  - PPA tariff – 7 INR / kWh
  - Utility trading margin – 1 INR / kWh

- **Therefore**

	Net Metering	Net Billing
Δx	50	200
Δy	150	150

1. Consumer owned model (Cap – Ex)

Net Metering Arrangement



Assuming that

- xn – Net meter reading for month “n”
- yn – Energy meter reading for month “n”
- Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff

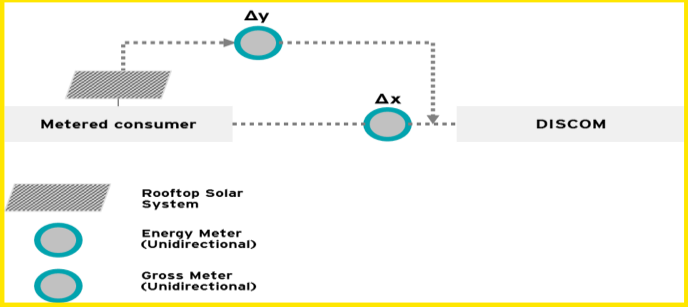
Electricity bill = Fixed charges + Δx*T

	Case 1 (BAU)		Case 2		
	Cash inflow	Cash outflow	Cash inflow	Cash outflow	Profit / loss as compared to base case
Utility	200 kWh X 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR		Loss of INR 500 - 2000 = - INR 1500
Consumer		200 kWh X 10 INR / kWh = 2000 INR	-	1.50 kWh x 10 INR / kWh = 500 INR 2.Operation & maintenance expenditure (hereinafter referred to as OME)	Savings of INR 2000 – (500 + OME)

	Revenue	Expenditure
Consumer		EPC fees
EPC	EPC fees	

1. Consumer owned model (Cap – Ex)

Net Billing Arrangement



Assuming that

- xn – Gross meter reading for month "n"
- yn – Energy meter reading for month "n"
- Δx – Total number of units (kWh) consumed i.e. xn – xn-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – Net Billing tariff

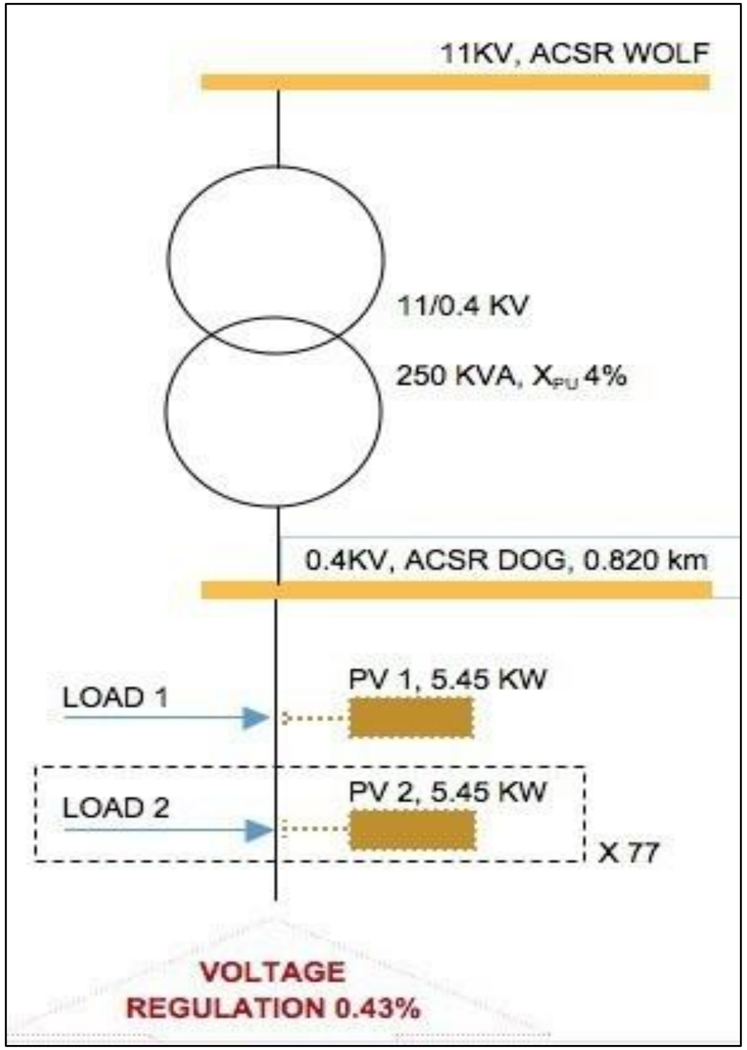
Electricity bill = Fixed charges + Δx*T - Δy*T'

	Case 1 (BAU)		Case 2		
	Cash inflow	Cash outflow	Cash inflow	Cash outflow	Profit / loss as compared to BAU
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	Loss of INR (2000 – 1200) – 2000 = -1200 INR
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	1.200 kWh x 10 INR / kWh = 2000 INR 2.OME	Savings of INR (1200 – 2000 – OME) + 2000 = INR 1200 – OME

	Revenue	Expenditure
Consumer		EPC fees
EPC	EPC fees	

System Study to assess maximum hosting capacity

- System study to assess maximum aggregated capacity of solar PV rooftop plants that can be connected to grid without impacting system operation within existing control and infrastructure configuration
- Impact assessment considering two key limiting parameters
  - Feeder/Grid asset thermal capacity
  - Over-voltage at point of interconnection
- Simulation model to conduct power flow analysis under different scenarios:
  - Different voltage level (0.4KV, 11 KV and 33KV)
  - Different DT capacity
  - Different loading conditions (rural, urban)



To provide recommendations to the regulations the impact of excess rooftop solar generation on the grid has been assessed

Load flow study

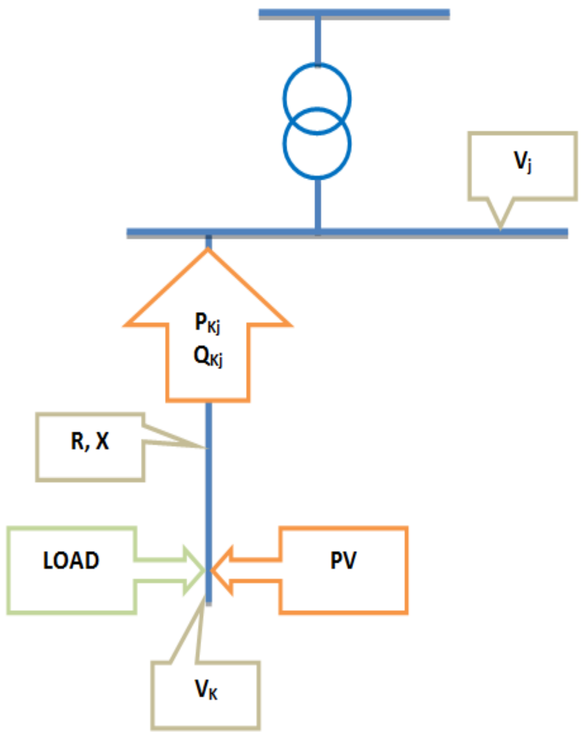
1. Reverse Power Flow will occur when Solar PV Generation goes beyond minimum running load (at consumer's place).

2. When such scenario occurs, Reverse Active Power 'Pkj' and Reverse Reactive Power 'Qkj', will enter into the Grid, and start feeding the neighbouring consumers.

3. If all loads are fed, the 'Pkj' and 'Qkj' will enter the 11 KV, through 'Distribution Transformer' itself, to feed the neighboring DTs, through 11 KV.

The basic equation to define Reverse Power Flow is -

Reverse Power Flow ($P_{reverse}$) = $P_{PV\ max}$ - $P_{LOAD\ min}$



11/0.4 KV FEEDER BLOCK DIAGRAM

Reverse Power Flow: Grid Asset(s) Loading How and Consequences

Load flow study

- When Photovoltaic generation exceeds ‘Minimum Running Load’, the excess generated KVA enters into the grid, to feed the neighboring consumers.

PV GENERATION > ‘MINIMUM RUNNING LOAD’, INVERTER INJECTS BACK INTO GRID

CONSEQUENCES

1. Excess heating of Grid Asset(s).

2. Reduced life of Transformers.

3. Permanent failure of Power Cables.

4. Worst - Grid Asset(s) Burnout

- During Injection, if Inverter's reverse current exceeds the Asset(s) rated amperage, the above mentioned points could be the outcome.

Reverse Power Flow: Feeder Voltage Rise
How and Consequences

Load flow study

- When Photovoltaic generation exceeds ‘Minimum Running Load’, the excess generated KVA enters into the grid, to feed the neighboring consumers.

PV GENERATION > ‘MINIMUM RUNNING LOAD’, INVERTER INJECTS BACK INTO GRID

CONSEQUENCES

1. Stress on Grid Asset(s) Insulation, such as that of Transformers and Power Cables.

2. Damage to Electronics, and other Voltage Sensitive equipments, at consumer’s places.

3. Again, heating of Grid Asset(s).

- With Injection, goes up the Voltage.
- Even with 5% Injection, Voltage rises notably.
- Voltage Regulation (VR) must be less than 8.43%, always.

Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	63.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.17%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	63.00	KW

LV Feeder Data

Enter Operating Power Fac	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.11	KVA
Enter Feeder Resistance - R	0.250	Ω/km
Enter Feeder Reactance - X	0.050	Ω/km
Enter Feeder Length:	0.100	km

PV Inverter Data

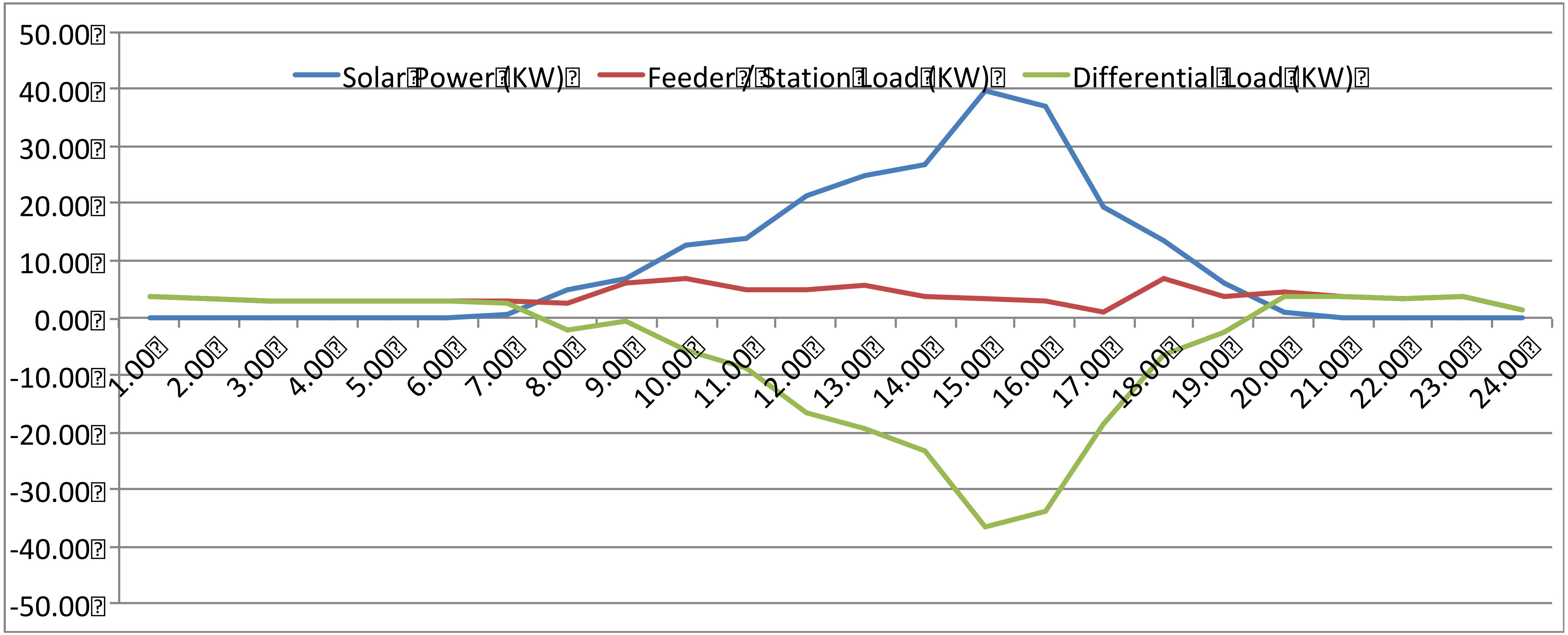
Operating Power Fact	1.00
Select Operating Mod	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	63.00	KVA
Peak PV Generation (KW):	63.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	107.80	W
Running Load Consumption (VAr):	21.89	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	62892.20	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	418.79	V
Feeder End Voltage Rise:	0.91%	
Acceptable:	Yes	
Feeder Running Load:	86.71	A
Feeder Ampacity:	87.65	A
Loading on Grid Assets:	98.93%	
Acceptable:	Yes	

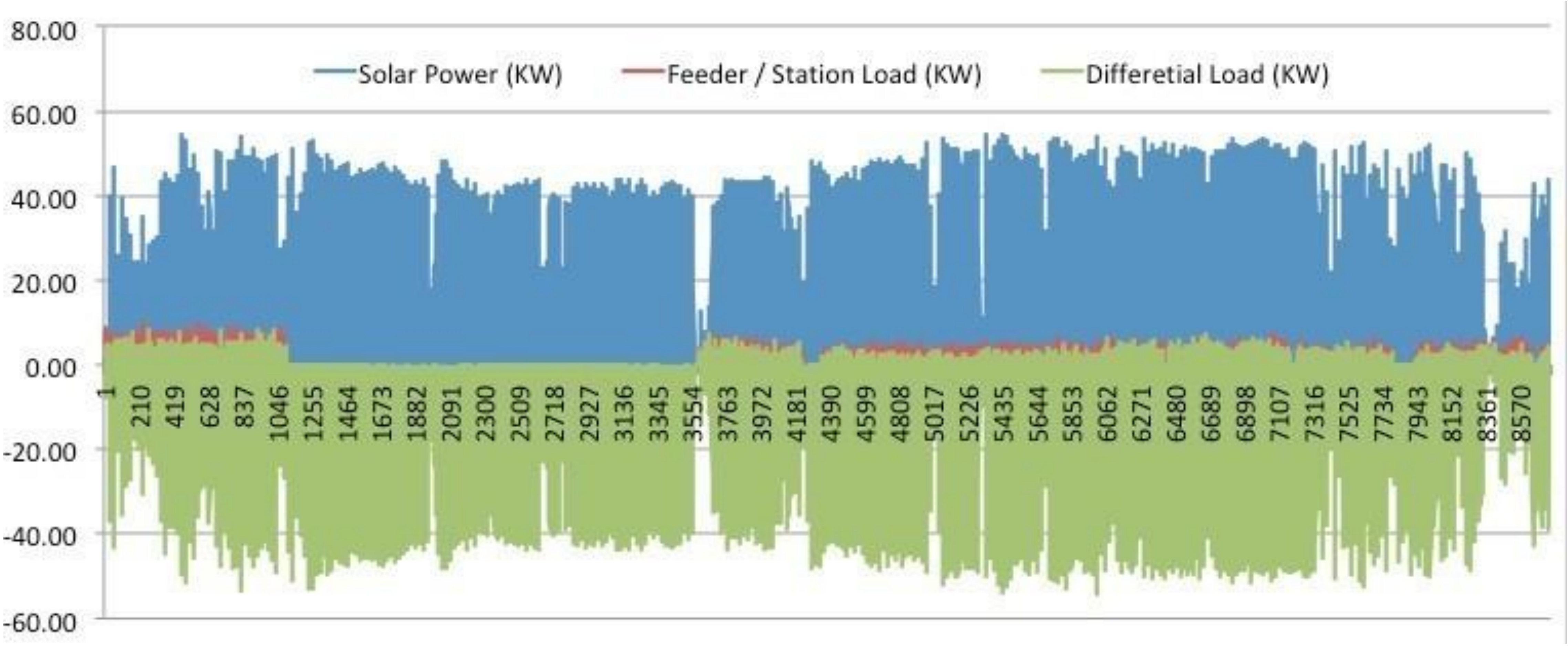
Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.02%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	100.00	KW

LV Feeder Data

Enter Operating Power Factor	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.02	KVA
Enter Feeder Resistance - R:	0.150	Ω/km
Enter Feeder Reactance - X_L:	0.075	Ω/km
Enter Feeder Length:	0.350	km

PV Inverter Data

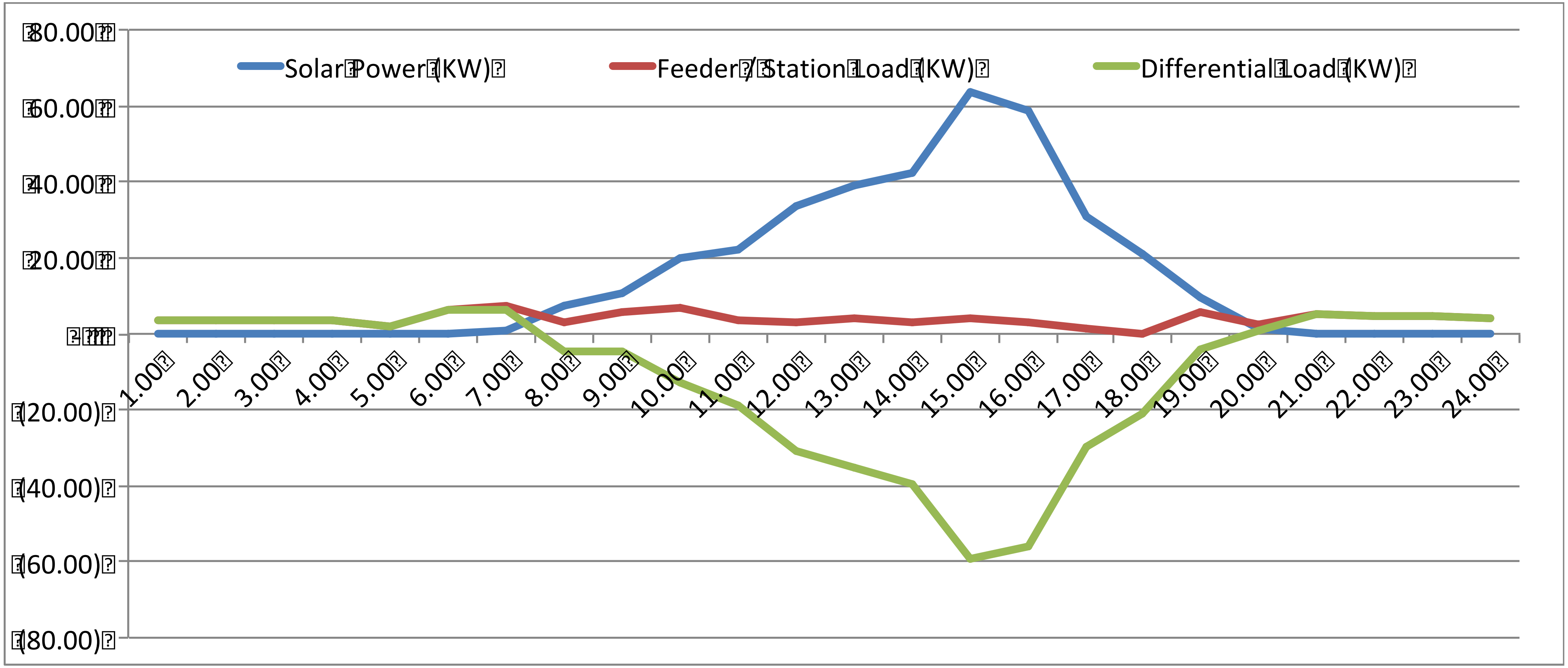
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	100.00	KVA
Peak PV Generation (KW):	100.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	23.52	W
Running Load Consumption (VAr):	4.78	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	99976.48	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	427.65	V
Feeder End Voltage Rise:	3.05%	
Acceptable:	Yes	
Feeder Running Load:	134.98	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	97.02%	
Acceptable:	Yes	

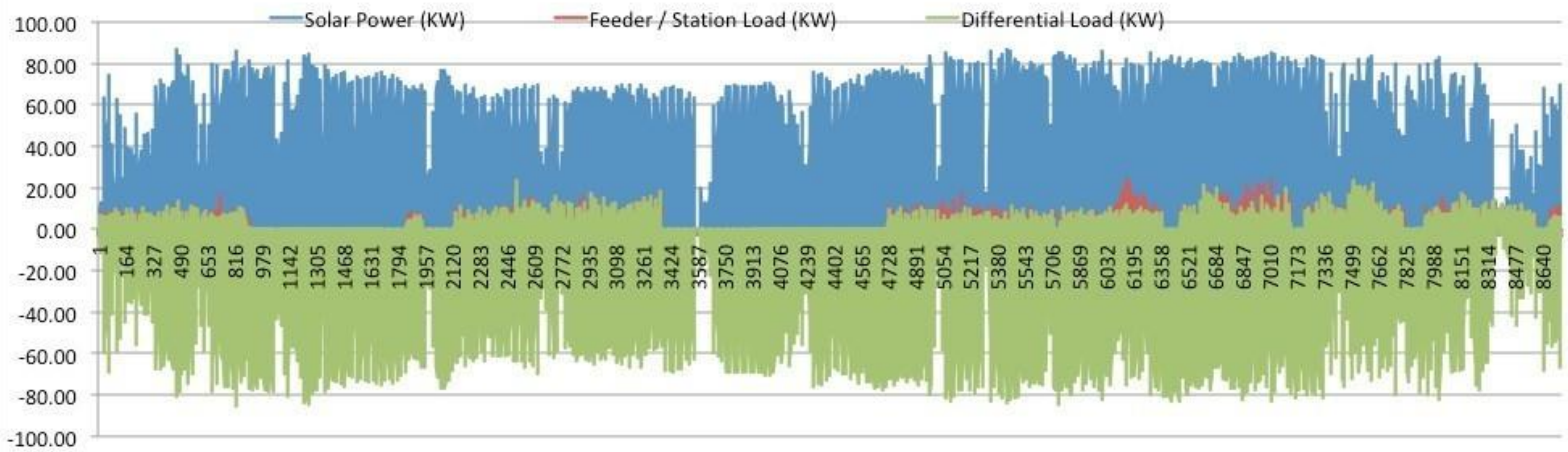
Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	1.56%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	101.00%	
PV Installed Capacity:	101.00	KW

LV Feeder Data

Enter Operating Power Factor	0.98	
Enter Load Quantity:	26	
Enter Running Load:	0.06	KVA
Enter Feeder Resistance - R:	0.279	Ω/km
Enter Feeder Reactance - X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

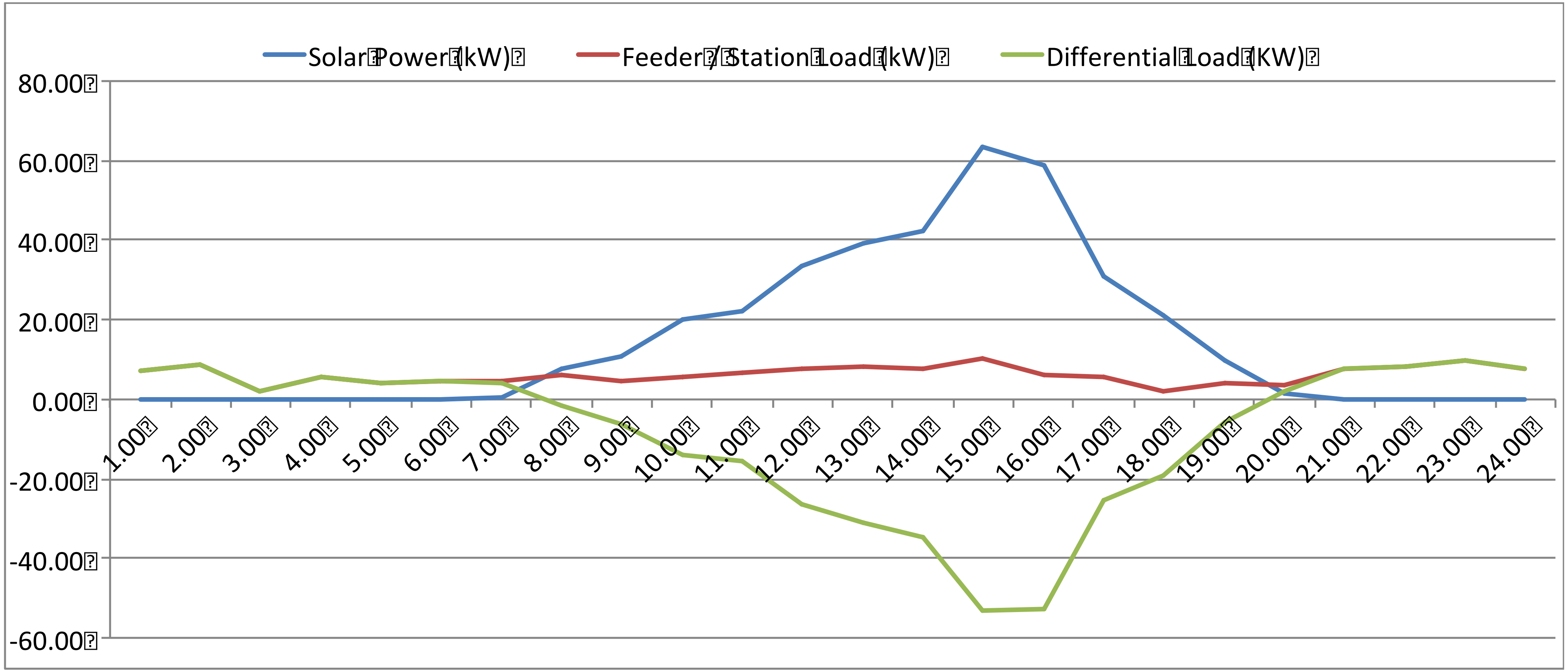
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	3.88	KVA
Peak PV Generation (KW):	3.88	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	58.80	W
Running Load Consumption (VAr):	11.94	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	3825.82	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	416.16	V
Feeder End Voltage Rise:	0.28%	
Acceptable:	Yes	
Feeder Running Load:	138.00	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	99.20%	
Acceptable:	Yes	

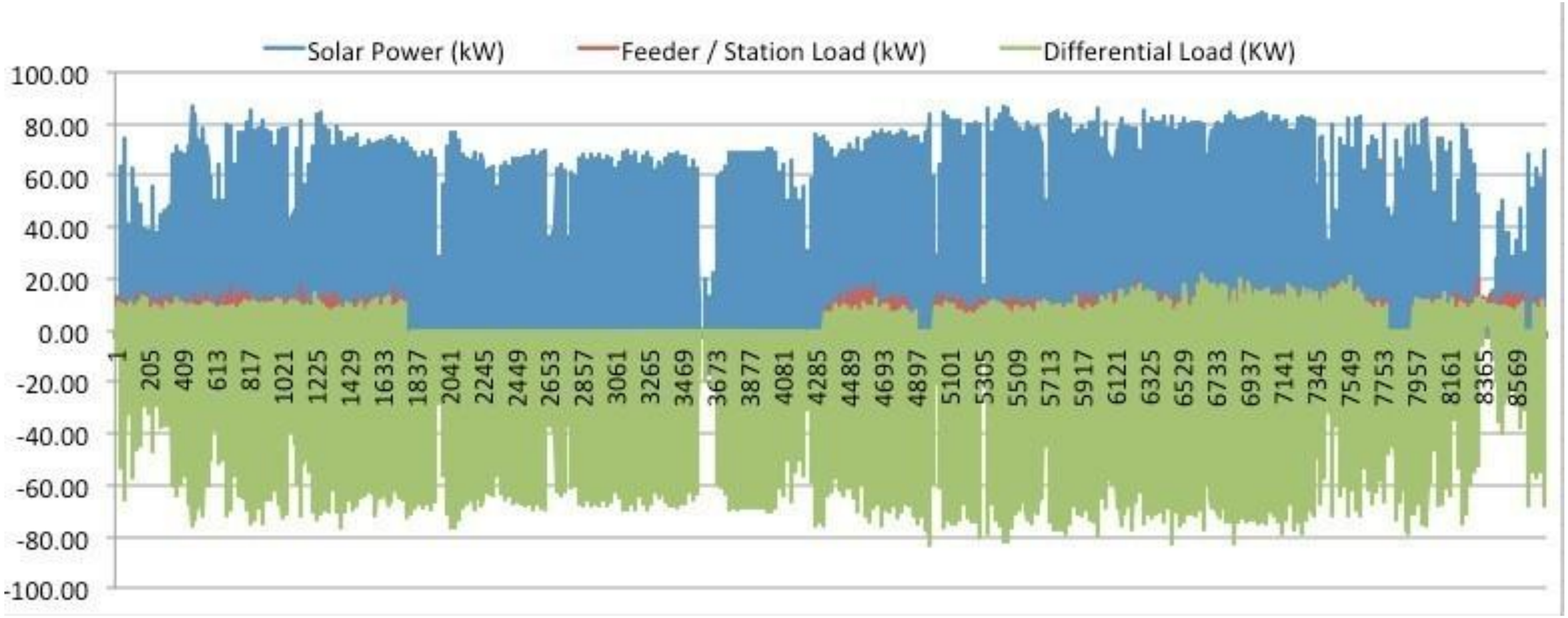
Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 4: 11KV feeder and 115KVA station at Ranchi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	115.00	KW

OUTPUTS

Peak PV Generation (KVA):	115.00	KVA
Peak PV Generation (KW):	115.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.31	W
Running Load Consumption (VAr):	0.92	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	114998.69	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11000.88	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	6.04	A
Feeder Ampacity:	6.04	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	16	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	0.650	km

LV Upstream Station Data

Enter Station Quantity:	1	
Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Station Per Unit Reactance – X_{PU}:	7.00%	
Station Base Reactance – X_{BASE}:	75625000	Ω
Station Actual Reactance – X_{Ω}:	5293750	Ω

MV Feeder Data

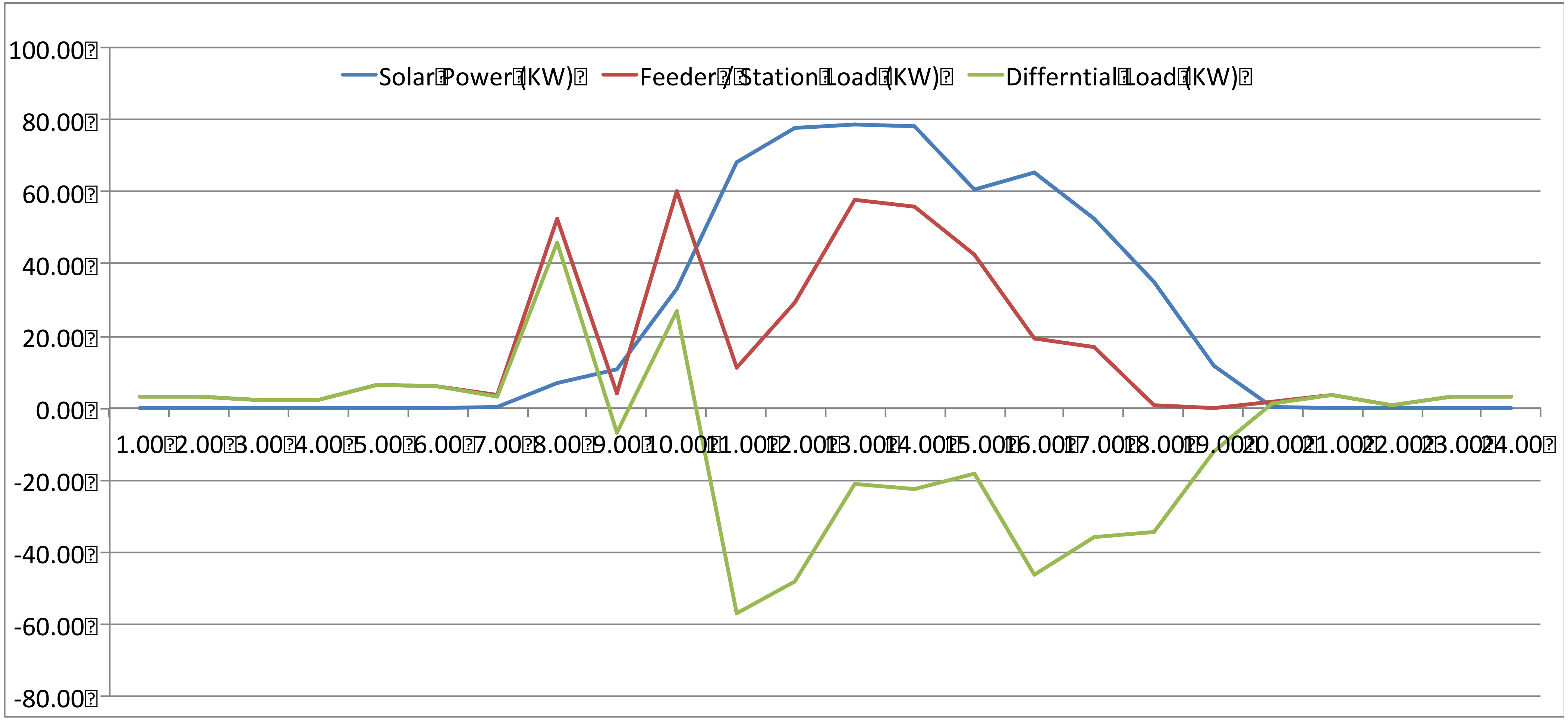
Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.82	
Enter Feeder Resistance – R:	0.187	Ω/km
Enter Feeder Reactance – X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	verexcited (lea

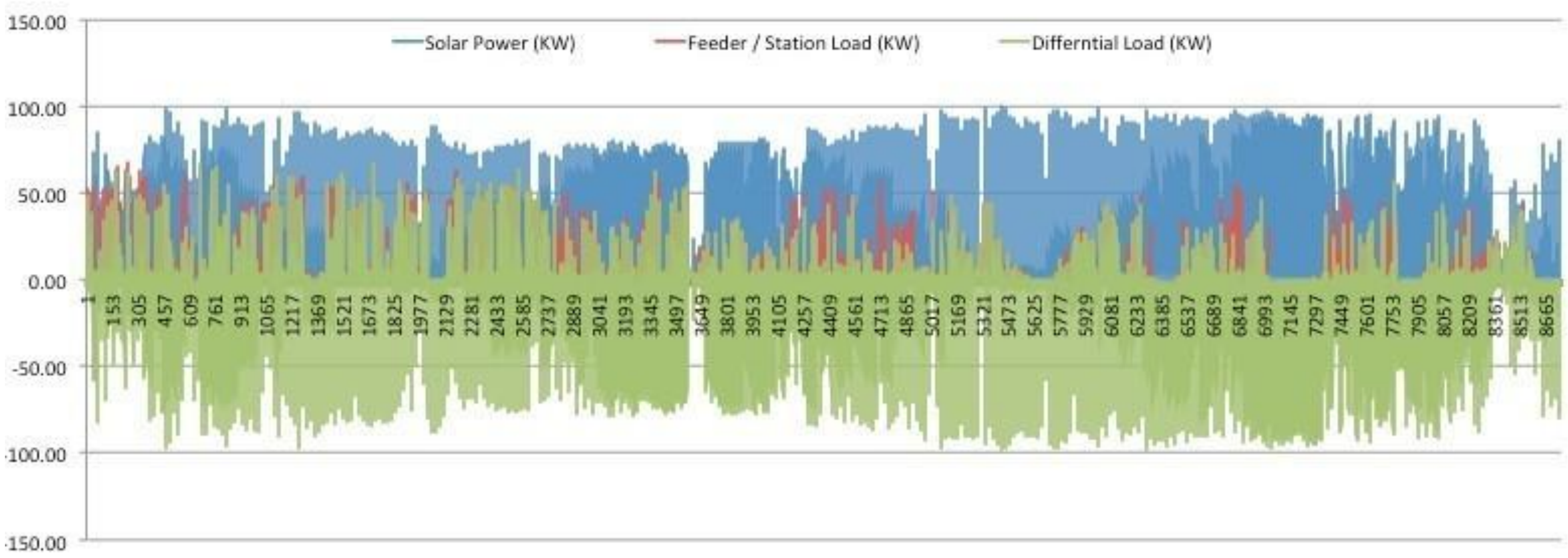
Case study 4: 11KV feeder and 115KVA station at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 4: 11KV feeder and 115KVA station at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 5: 11KV feeder and 140KVA station at Ranchi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	140.00	KW

OUTPUTS

Peak PV Generation (KVA):	140.00	KVA
Peak PV Generation (KW):	140.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.76	W
Running Load Consumption (VAr):	0.36	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	139998	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11001.07	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	7.35	A
Feeder Ampacity:	7.35	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	18	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Enter Station Per Unit Reactance – X_{PU}:	7.00%	
Station Base Reactance – X_{BASE}:	67222222	Ω
Station Actual Reactance – X_{Ω}:	4705556	Ω

MV Feeder Data

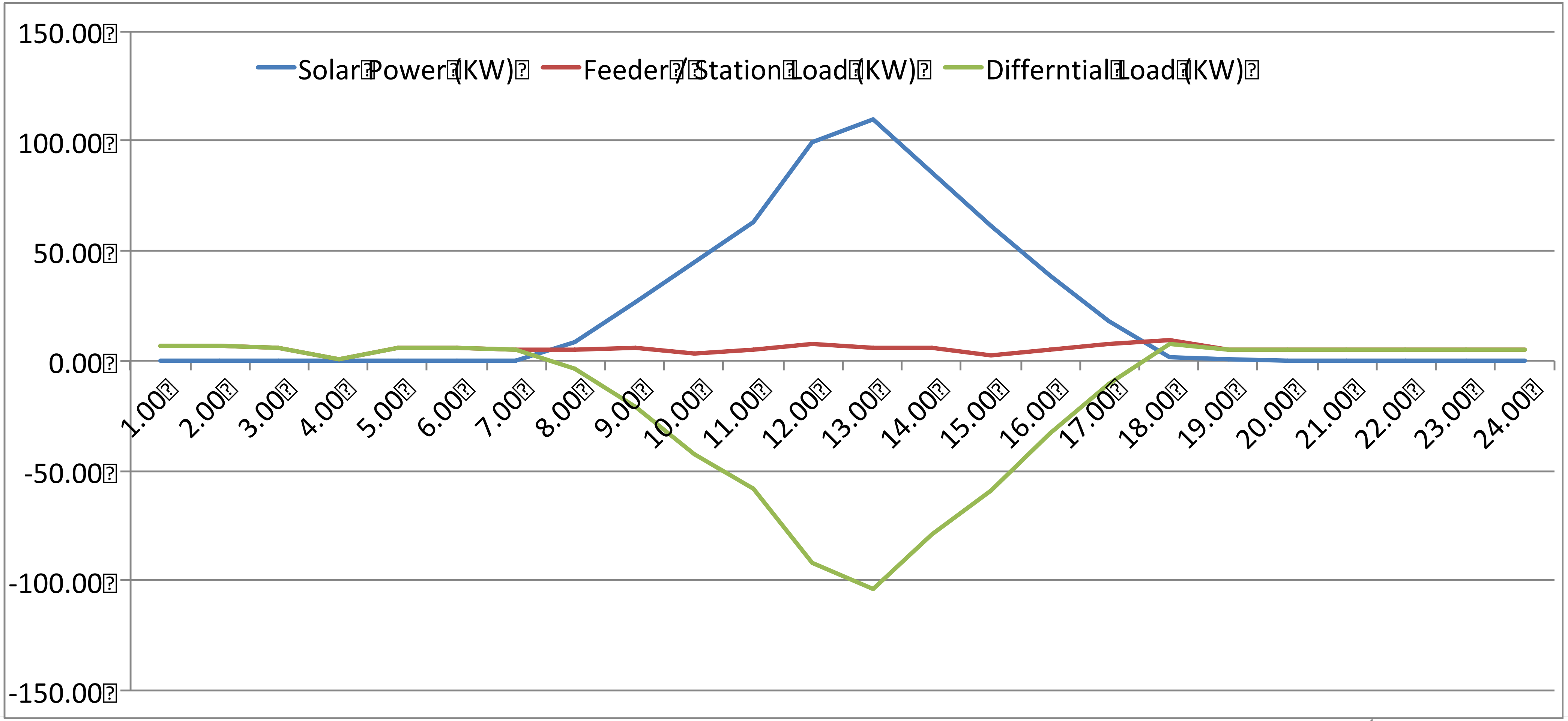
Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.98	
Enter Feeder Resistance – R:	0.187	Ω/km
Enter Feeder Reactance – X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

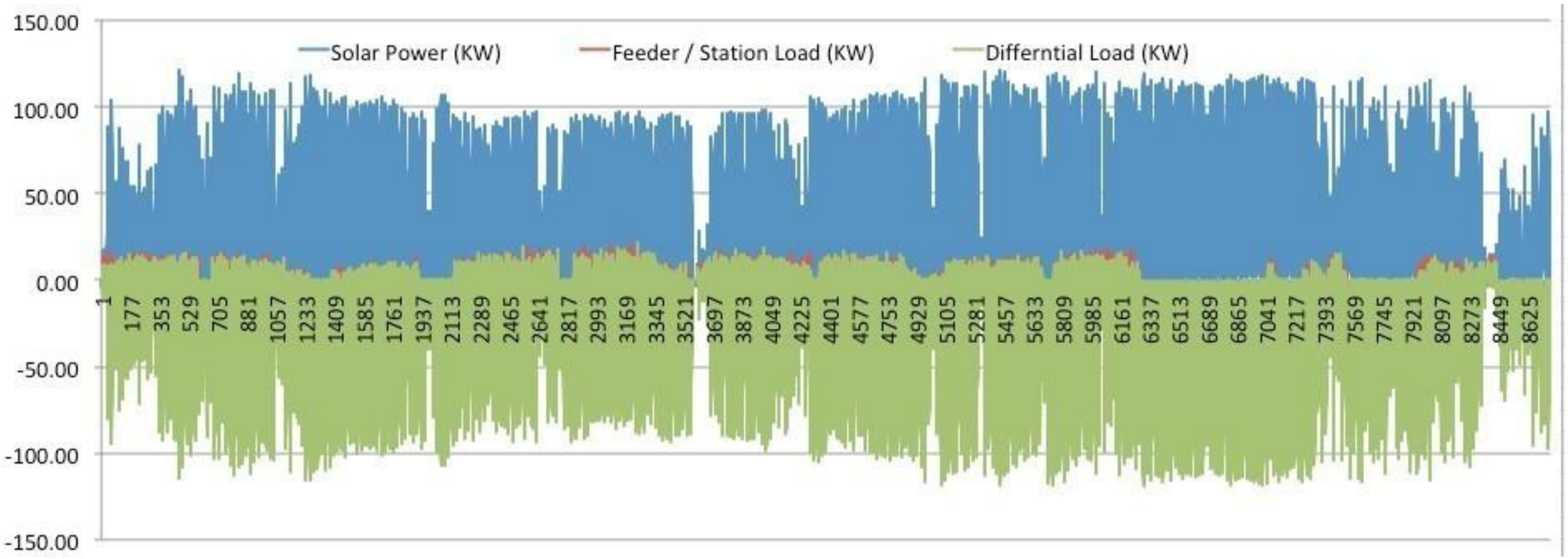
Case study 5: 11KV feeder and 140KVA station at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 5: 11KV feeder and 140KVA station at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 6: 11KV feeder and 630KVA station at Delhi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	630.00	KVA
Station Primary Voltage:	33000	V
Station Secondary Voltage:	11000	V
Station Running Capacity:	12.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100%	
Enter PV Penetration:	112%	
PV Installed Capacity:	705.60	KW

LV Feeder Data

Enter Operating Power Factor:	0.96	
Enter Load Quantity:	62	
Enter Running Load:	1.26	KVA
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	1	
Station Installed Capacity:	630	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	12.41%	
Station Running Capacity:	78.18	KVA
Station Per Unit Reactance – X_{PU}:	6.00%	
Station Base Reactance – X_{BASE}:	1548	Ω
Station Actual Reactance – X_{Ω}:	92.86	Ω

MV Feeder Data

Operating Power Factor:	0.94	
Enter Adjusted Power Factor	0.98	
Enter Feeder Resistance – R:	0.150	Ω/km
Enter Feeder Reactance – X_L:	0.100	Ω/km
Enter Feeder Length:	0.750	km

PV Inverter Data

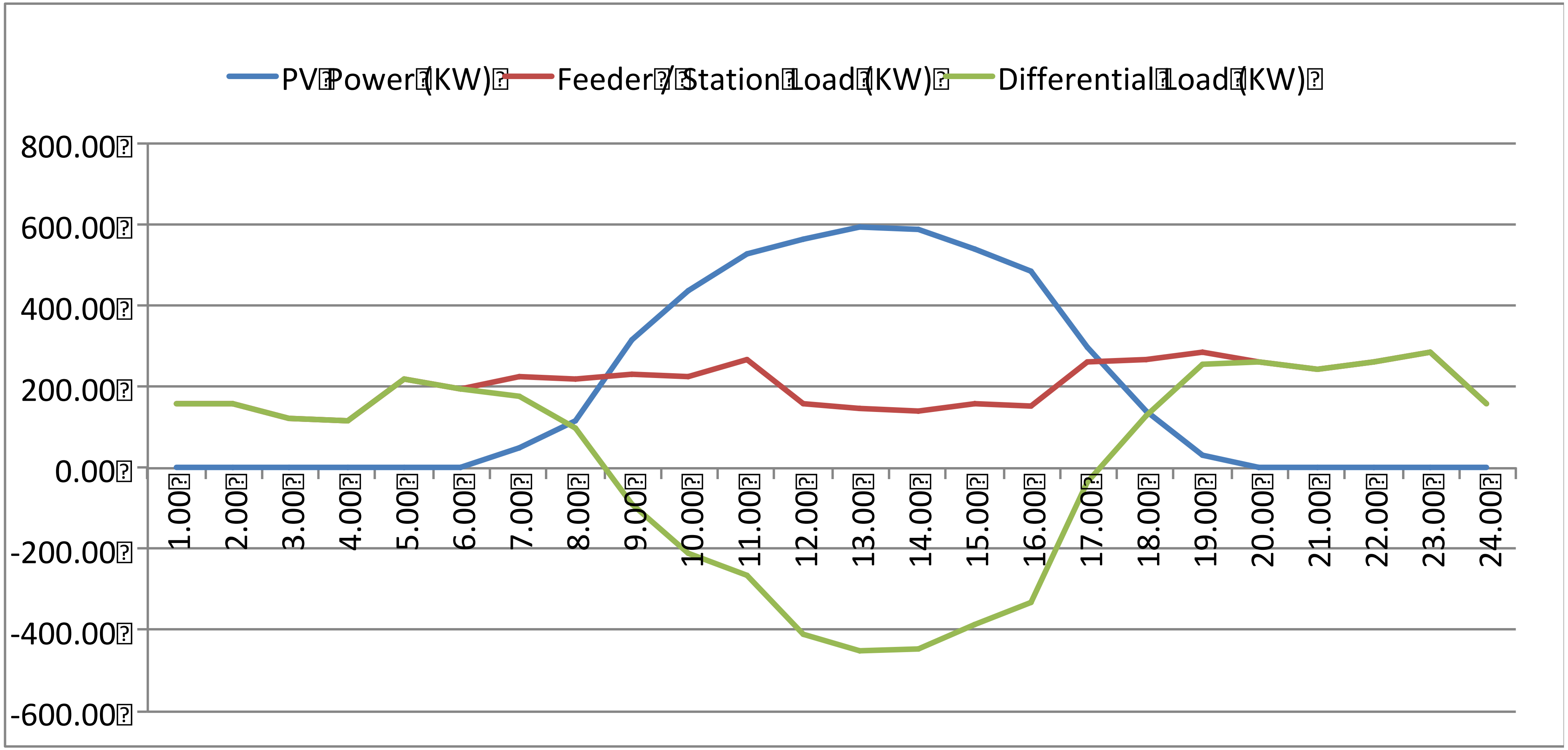
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

OUTPUTS

Peak PV Generation (KVA):	706	KVA
Peak PV Generation (KW):	706	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	76618	W
Running Load Consumption (VAr):	15558	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	628982	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11008	V
Feeder End Voltage Rise:	0.08%	
Acceptable:	Yes	
Feeder Running Load:	33.00	A
Feeder Ampacity:	33.07	A
Loading of Grid Assets:	99.79%	
Acceptable:	Yes	

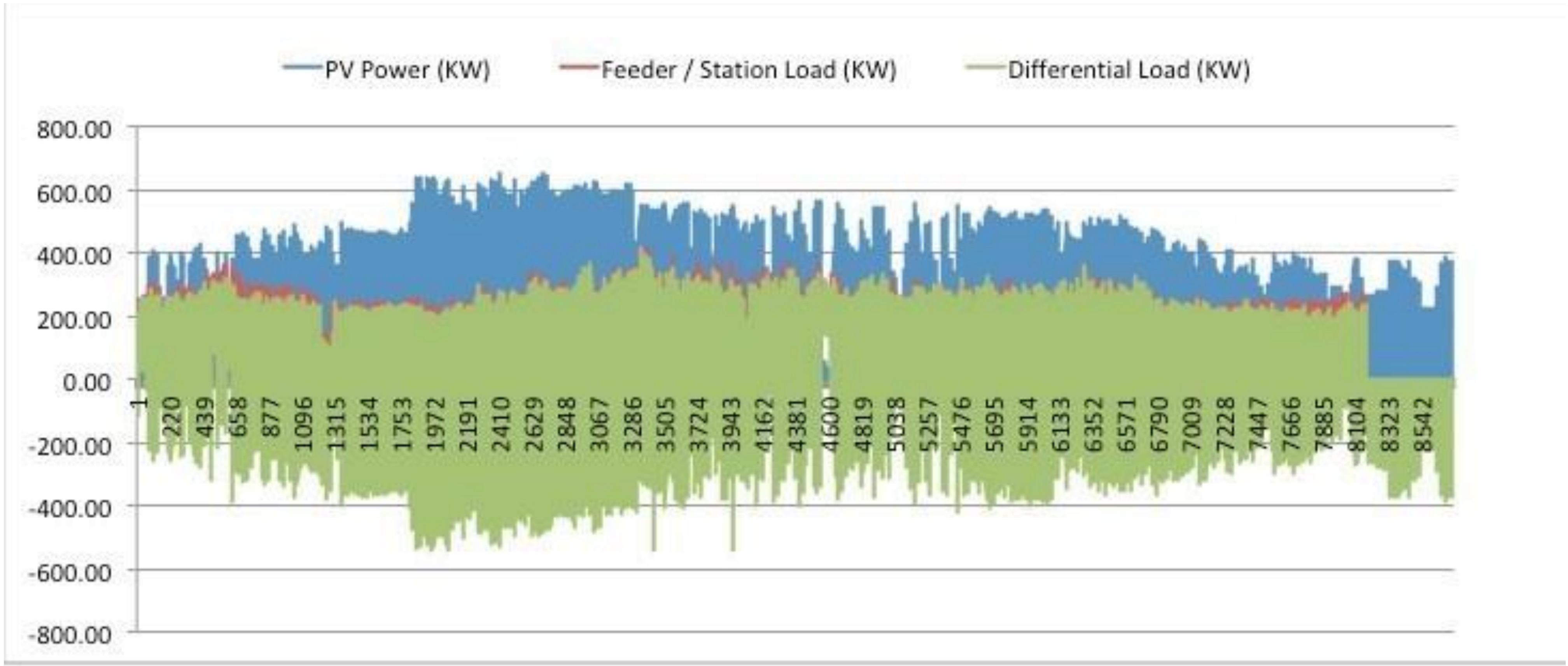
Case study 6: 11KV feeder and 630KVA station at Delhi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 6: 11KV feeder and 630KVA station at Delhi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	11000	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	11.78%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	111.00%	
PV Installed Capacity:	12210	KW

OUTPUTS

Peak PV Generation (KVA):	12210	KVA
Peak PV Generation (KW):	12210	KW
Peak PV Generation (KVAr):	0	KVAr
Running Load Consumption (W):	1231200	W
Running Load Consumption (VAr):	404676	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	10978800	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33458	V
Feeder End Voltage Rise:	1.39%	
Acceptable:	Yes	
Feeder Running Load:	189.58	A
Feeder Ampacity:	192.46	A
Loading of Grid Assets:	98.51%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	30	
Enter Running Load:	10.80	KVA
Enter Feeder Resistance : R:	0.450	Ω/km
Enter Feeder Reactance : X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	4	
Enter Station Installed Capacity:	2750.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	324.00	KVA
Station Per Unit Reactance : X_{PU}:	6.00%	
Station Base Reactance : X_{BASE}:	373.46	Ω
Station Actual Reactance : $X_{Ω}$:	22.41	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance : R:	0.350	Ω/km
Enter Feeder Reactance : X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	11000.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	1296.00	KVA
Station Per Unit Reactance : X_{PU}:	7.00%	
Station Base Reactance : X_{BASE}:	840.28	Ω
Station Actual Reactance : $X_{Ω}$:	58.82	Ω

HV Feeder Data

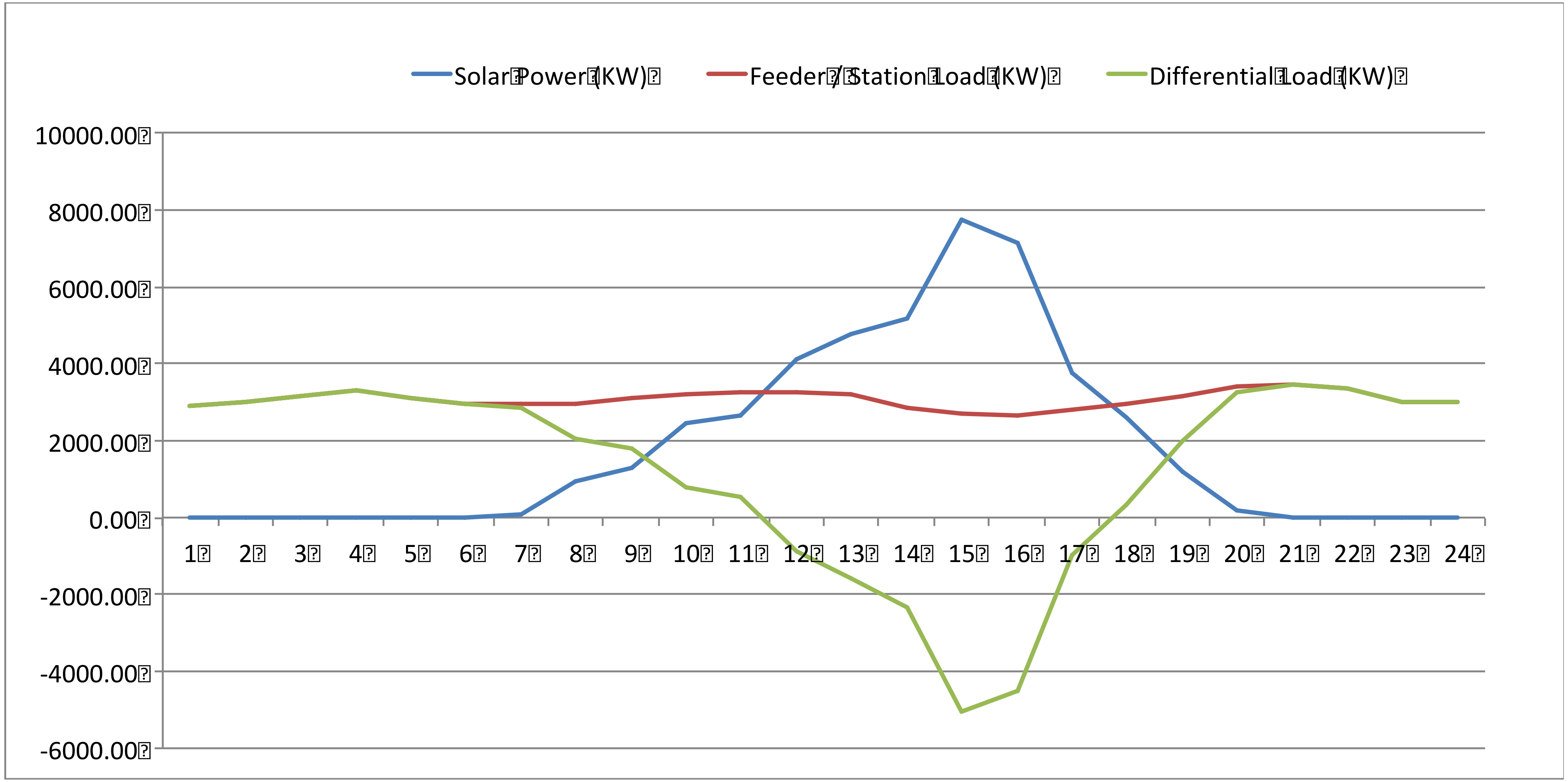
Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.95	
Enter Feeder Resistance : R:	0.139	Ω/km
Enter Feeder Reactance : X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

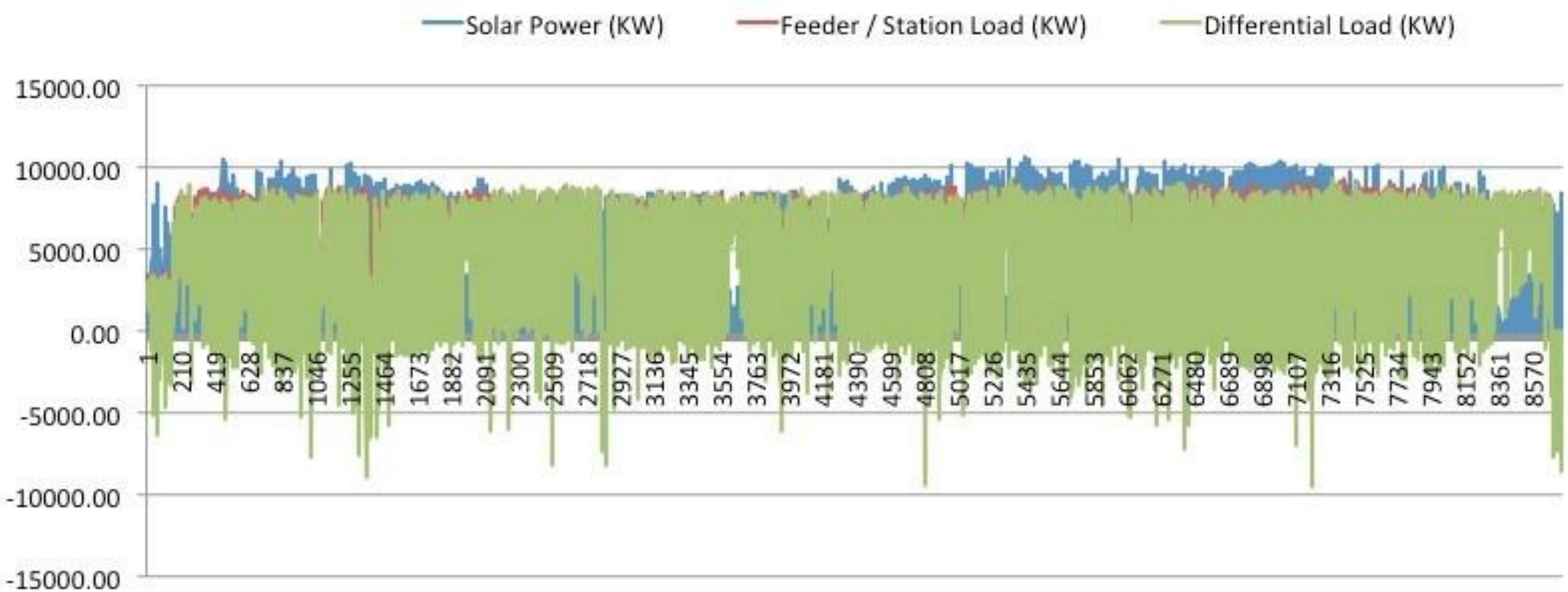
Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	1750	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	0.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	1750	KW

OUTPUTS

Peak PV Generation (KVA):	1750	KVA
Peak PV Generation (KW):	1750	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	6624	W
Running Load Consumption (VAr):	2822	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	1743376	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33070	V
Feeder End Voltage Rise:	0.21%	
Acceptable:	Yes	
Feeder Running Load:	30.44	A
Feeder Ampacity:	30.62	A
Loading of Grid Assets:	99.41%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	16	
Enter Running Load:	0.23	KVA
Enter Feeder Resistance – R:	0.450	Ω/km
Enter Feeder Reactance – X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	2	
Enter Station Installed Capacity:	875.00	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415	V
Station Running Capacity:	0.41%	
Station Running Capacity:	3.60	KVA
Station Per Unit Reactance – X_{PU}:	6.00%	
Station Base Reactance – X_{BASE}:	33611	Ω
Station Actual Reactance – X_{Ω}:	2017	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	1750.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.41%	
Station Running Capacity:	7.20	KVA
Station Per Unit Reactance – X_{PU}:	7.00%	
Station Base Reactance – X_{BASE}:	151250	Ω
Station Actual Reactance – X_{Ω}:	10588	Ω

HV Feeder Data

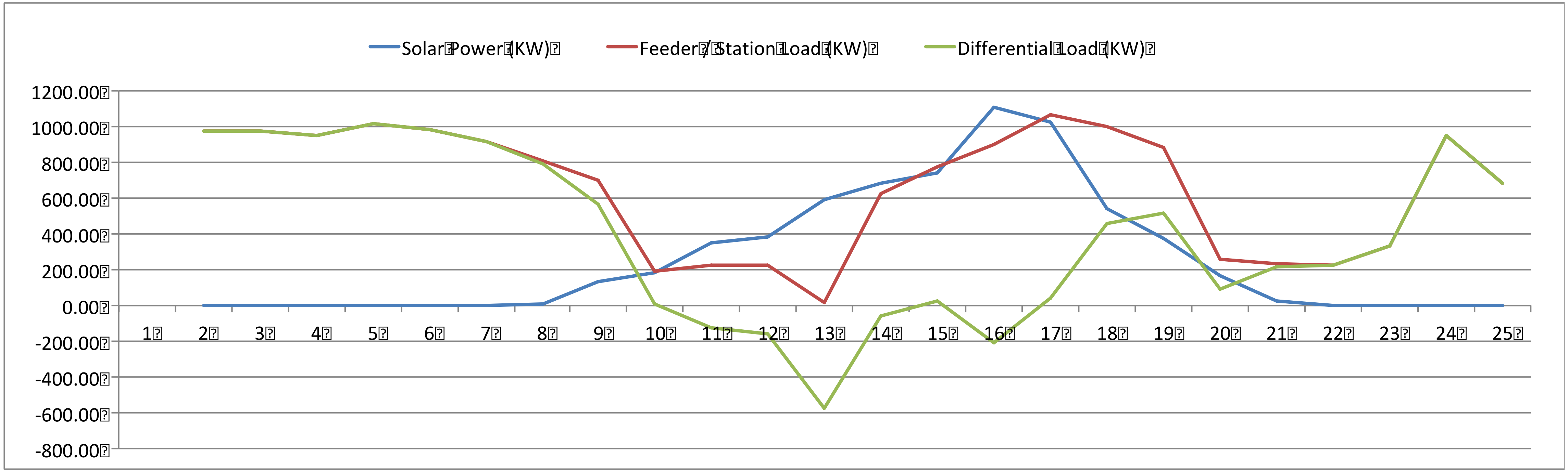
Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.92	
Enter Feeder Resistance – R:	0.139	Ω/km
Enter Feeder Reactance – X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

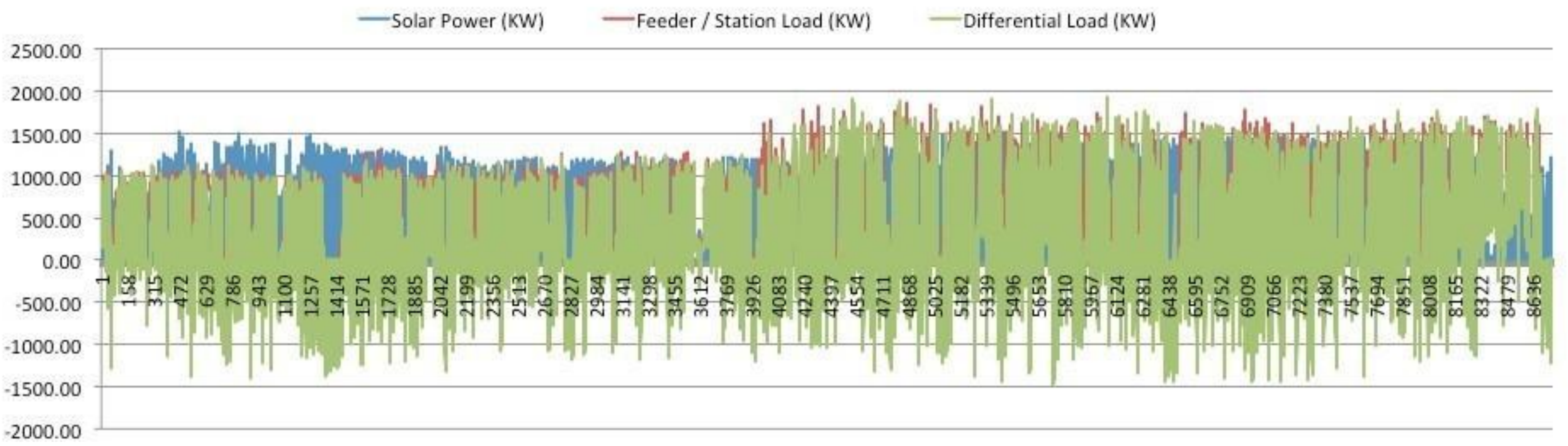
Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

Annual load profile showing Solar Power, Consumer Load and Differential load



Benefit analysis for a utility: Jharkhand & Delhi case study (1/3)

An analytical model was developed to assess the financial impact of rooftop solar penetration on the distribution utility in the geography.

The model was utilised to assess the financial impact of rooftop solar penetration on **JBVNL, Jharkhand and BYPL, Delhi**.

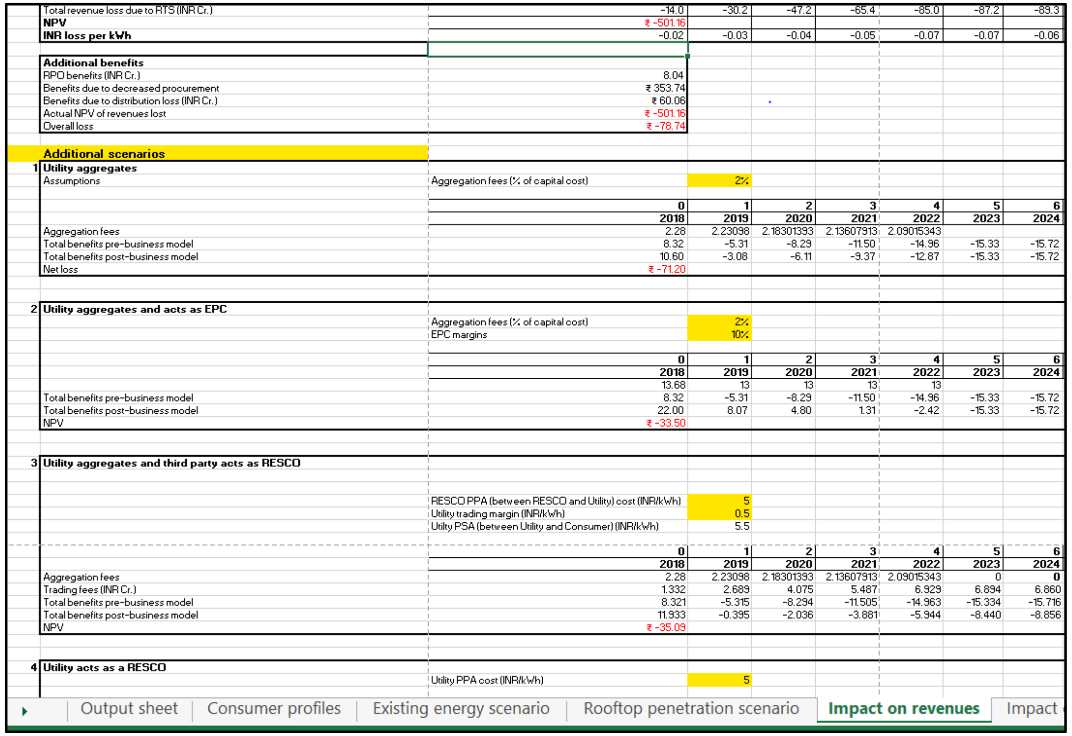
Key considerations for developing the impact model were as follows

- **The abovementioned 6 business models were considered for the assessment**
- **Following rooftop solar penetration scenarios were considered**
  - **MNRE Targets**
  - **10% growth**
  - **20% growth**
  - **30% growth**
  - **40% growth**
- **Existing tariff structures, APPC, ACoS, distribution losses and RPOs for DISCOMs were considered as mentioned in the ARR for developing the impact model**

Benefit analysis for a utility: Jharkhand & Delhi case study (2/3)

Key output of the analytical model is the financial impact on the utility due to uptake of rooftop solar in its distribution circle. Impact on utility due to utility-centric business models is also assessed.

Snapshots from the model:



		2018	2019	2020	2021	2022	2023	2024
Total revenue loss due to RTS (INR Cr.)		-14.0	-30.2	-47.2	-65.4	-85.0	-87.2	-89.3
NPV		₹ -501.16						
INR loss per kWh		-0.02	-0.03	-0.04	-0.05	-0.07	-0.07	-0.06

Additional benefits	
RPO benefits (INR Cr.)	8.04
Benefits due to decreased procurement	₹ 353.74
Benefits due to distribution loss (INR Cr.)	₹ 60.06
Actual NPV of revenues lost	₹ -501.16
Overall loss	₹ -78.74

Additional scenarios

1 **Utility aggregates**

Assumptions — Aggregation fees (% of capital cost): 2%

	0	1	2	3	4	5	6
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Aggregation fees	2.28	2.23098	2.18301393	2.13607913	2.09015343		
Total benefits pre-business model	8.32	-5.31	-8.29	-11.50	-14.96	-15.33	-15.72
Total benefits post-business model	10.60	-3.08	-6.11	-9.37	-12.87	-15.33	-15.72
Net loss	₹ -71.20						

2 **Utility aggregates and acts as EPC**

Aggregation fees (% of capital cost): 2%
EPC margins: 10%

	0	1	2	3	4	5	6
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
	13.68	13	13	13	13		
Total benefits pre-business model	8.32	-5.31	-8.29	-11.50	-14.96	-15.33	-15.72
Total benefits post-business model	22.00	8.07	4.80	1.31	-2.42	-15.33	-15.72
NPV	₹ -33.50						

3 **Utility aggregates and third party acts as RESCO**

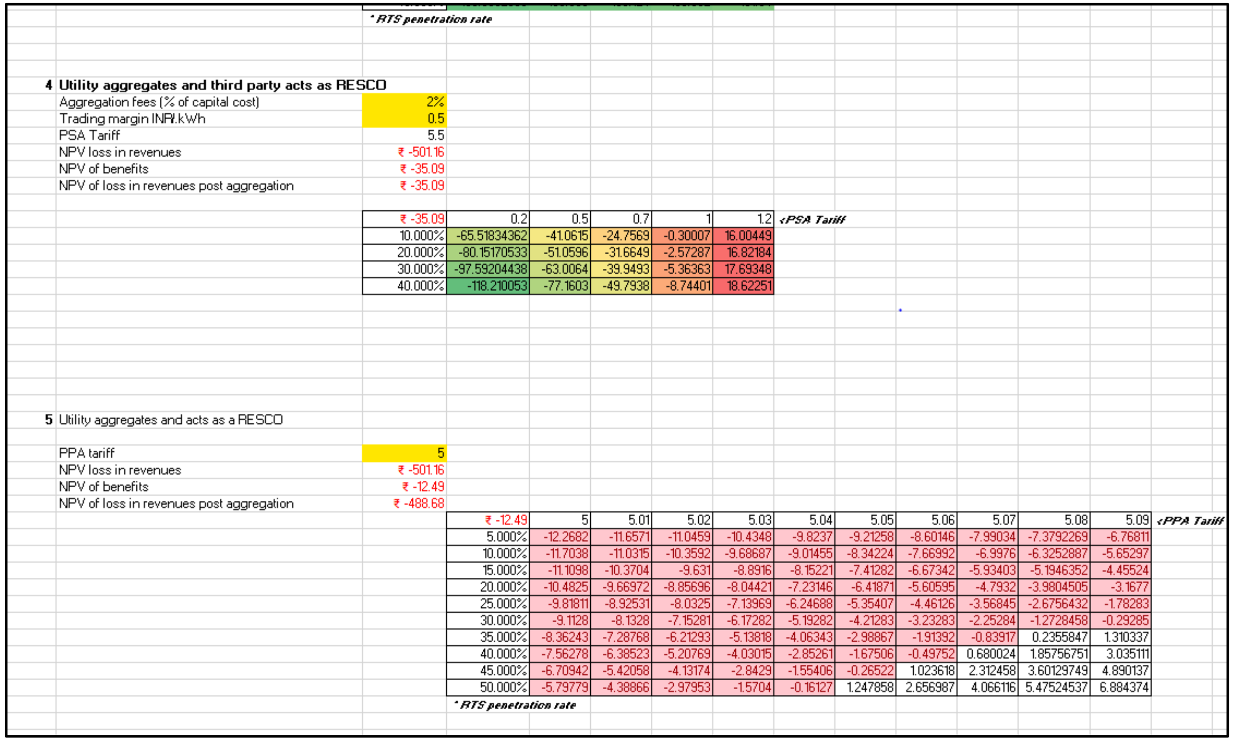
RESCO PPA (between RESCO and Utility) cost (INR/kWh): 5
Utility trading margin (INR/kWh): 0.5
Utlity PSA (between Utility and Consumer) (INR/kWh): 5.5

	0	1	2	3	4	5	6
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Aggregation fees	2.28	2.23098	2.18301393	2.13607913	2.09015343	0	0
Trading fees (INR Cr.)	1.332	2.689	4.075	5.487	6.929	6.894	6.860
Total benefits pre-business model	8.321	-5.315	-8.294	-11.505	-14.963	-15.334	-15.716
Total benefits post-business model	11.933	-0.395	-2.036	-3.881	-5.944	-8.440	-8.856
NPV	₹ -35.09						

4 **Utility acts as a RESCO**

Utility PPA cost (INR/kWh): 5

Output sheet | Consumer profiles | Existing energy scenario | Rooftop penetration scenario | **Impact on revenues** | Impact



*RTS penetration rate

4 **Utility aggregates and third party acts as RESCO**

Aggregation fees (% of capital cost)	2%
Trading margin INR/.kWh	0.5
PSA Tariff	5.5
NPV loss in revenues	₹ -501.16
NPV of benefits	₹ -35.09
NPV of loss in revenues post aggregation	₹ -35.09

₹ -35.09	0.2	0.5	0.7	1	1.2	<PSA Tariff
10.000%	-65.51834362	-41.0615	-24.7569	-0.30007	16.00449	
20.000%	-80.15170533	-51.0596	-31.6649	-2.57287	16.82184	
30.000%	-97.59204438	-63.0064	-39.9493	-5.36363	17.69348	
40.000%	-118.210053	-77.1603	-49.7938	-8.74401	18.62251	

5 Utility aggregates and acts as a RESCO

PPA tariff	5
NPV loss in revenues	₹ -501.16
NPV of benefits	₹ -12.49
NPV of loss in revenues post aggregation	₹ -488.68

₹ -12.49	5	5.01	5.02	5.03	5.04	5.05	5.06	5.07	5.08	5.09	<PPA Tariff
5.000%	-12.2682	-11.6571	-11.0459	-10.4348	-9.8237	-9.21258	-8.60146	-7.99034	-7.3792269	-6.76811	
10.000%	-11.7038	-11.0315	-10.3592	-9.68687	-9.01455	-8.34224	-7.66992	-6.9976	-6.3252887	-5.65297	
15.000%	-11.1098	-10.3704	-9.631	-8.8916	-8.15221	-7.41282	-6.67342	-5.93403	-5.1946352	-4.45524	
20.000%	-10.4825	-9.66972	-8.85696	-8.04421	-7.23146	-6.41871	-5.60595	-4.7932	-3.9804505	-3.1677	
25.000%	-9.81811	-8.92531	-8.0325	-7.13969	-6.24688	-5.35407	-4.46126	-3.56845	-2.6756432	-1.78283	
30.000%	-9.1128	-8.1328	-7.15281	-6.17282	-5.19282	-4.21283	-3.23283	-2.25284	-1.2728458	-0.29285	
35.000%	-8.36243	-7.28768	-6.21293	-5.13818	-4.06343	-2.98867	-1.91392	-0.83917	0.2355847	1.310337	
40.000%	-7.56278	-6.38523	-5.20769	-4.03015	-2.85261	-1.67506	-0.49752	0.680024	1.85756751	3.035111	
45.000%	-6.70942	-5.42058	-4.13174	-2.8429	-1.55406	-0.26522	1.023618	2.312458	3.60129749	4.890137	
50.000%	-5.79779	-4.38866	-2.97953	-1.5704	-0.16127	1.247858	2.656987	4.066116	5.47524537	6.884374	

*RTS penetration rate

Hyperlinks to the models are as follows - Model for JBVNL Model for BYPL

Microsoft Excel Worksheet

Microsoft Excel Worksheet

Benefit analysis for a utility: Jharkhand & Delhi case study (3/3)

Key observations
• Rooftop solar installations provides various commercial benefits to the utilities such as RPO benefits, reduced AT&C losses and benefits due to reduced power procurement. **Recommendation** - To restructure the tariffs with higher fixed charges and lower energy charges to optimize DISCOMs revenues.
• Only "Utility as a RESCO" business model returns a profit or a no-profit-no-loss scenario. Sensitivity analysis was utilised to determine the PPA tariff for the utility for a no-profit-no-loss scenario under the "Utility as a RESCO" business model. • For JBVNL, the PPA tariff was determined to be in the range of 5.74 – 5.75 INR/kWh. • For BYPL, the PPA tariff was determined to be in the range of 7.4 – 7.5 INR/kWh. • The PPA tariff is higher in Delhi as compared with Jharkhand due to higher retail tariffs and lower AT&C losses in Delhi. The "Utility as a RESCO" model will be financially feasible on in the case of commercial consumer segment. **Recommendation** – To provide a facilitative regulatory environment to encourage DISCOM participation as RESCOs (Utility as a RESCO business model)

Benefit analysis for a utility: Key observations from Jharkhand & Delhi case study (1/4)

Business model	Key observations
CAPEX and RESCO, Utility aggregation	• Any penetration of rooftop solar will result in loss of revenues for the utility. • Actual loss to the utility is ~15 – 25% of the revenue loss to the utility due to compensation by reduced procurement, reduced losses and RPO benefits. **Recommendation** - To restructure the tariffs with higher fixed charges and lower energy charges to optimize DISCOMs revenues.
Utility as EPC	• The actual loss to the utility is reduced by ~10-25% compared to the previous business models. **Recommendation** - To restructure the tariffs with higher fixed charges and lower energy charges to optimize DISCOMs revenues.

Benefit analysis for a utility: Key observations from Jharkhand case study (2/4)

Business model	Key observations
Utility aggregates and third party acts as RESCO	• The actual loss/benefits are dependant on the penetration growth rate and trading margin for the DISCOMs. • For Jharkhand, for a no-benefit & no-loss scenario, trading margin for the DISCOM lies between 1-1.04 INR/kWh for penetration growth rates 5-20%. • For Delhi, the trading margin lies between 2.4-2.5 INR/kWh for a no-benefit & no-loss scenario due to higher retail tariffs and lower AT&C losses. To make up the lost revenue, due to rooftop solar, the utility will have to charge a higher trading margin. **Recommendation** – To identify the trading margin based on the above-mentioned factors and the current grid tariffs. Consumers will not uptake rooftop if landed PPA tariff > grid tariff.

Benefit analysis for a utility: Key observations from Jharkhand case study (3/4)

Business model	Key observations
Utility aggregates and acts as RESCO	• The utility will be able to **retain or increase** their revenues based on the penetration growth rates and PPA tariff. • For Jharkhand, for a no-benefit and no-loss scenario, PPA tariffs can be selected between 5.0 – 5.2 INR/kWh based on the penetration growth rates (Range: 10%-100%) • For Delhi, PPA tariff was determined to be in the range of 7.4 – 7.5 INR/kWh. The PPA tariff is higher in Delhi as compared with Jharkhand due to higher retail tariffs and lower AT&C losses in Delhi. The “Utility as a RESCO” model will be financially feasible on in the case of commercial consumer segment. **Recommendation** – To select the PPA tariff, the abovementioned factors and the grid tariffs should be taken into consideration.

Benefit analysis for a utility: Key observations from Jharkhand case study (4/4)

Other observations

- The following measures can also be selected for optimising revenues for the utilities –
  - Restructuring the tariffs with higher fixed charges and lower energy charges
  - Implementing ToD tariffs
  - Implementing separate tariff slabs for rooftop solar consumers (higher fixed charges for rooftop solar consumers)
- Actual losses are only a (~15%) of the revenue losses due to rooftop solar penetration
- Penetration scenarios within consumer segments are key to assess revenue loss for DISCOM
- The trading margin and the PPA tariff for the DISCOM should be selected based on the existing tariff structure & rooftop solar penetration growth and other factors assumed in the detailed model such as RPO benefits, tariff escalation, AT&C losses etc.
- Benefits due to decrease in distribution losses and benefits due to RPO benefits as high as 25% of the total expected revenue loss

Important definitions and key concepts introduced

PDRES — Prosumer Distributed Renewable Energy System

- A distributed renewable energy system set up by prosumer under net metering or net billing, connected on the prosumer side of the meter or on service line to the prosumer.

IDRES — Independent Distributed Renewable Energy System

- A distributed renewable energy system set up by any person and is connected to the distribution licensee network and sells electricity to distribution licensee under Power Purchase Agreement;

Prosumer	Renewable Energy Service Company (RESCO)	Distributed Renewable Energy Sources (DRES)
• A person who consumes electricity from the grid and can also inject electricity into the grid using same network from renewable energy system set up on consumer side of the meter.	• RESCO means an energy service company **which owns a renewable energy system** and **provides renewable energy to the consumer**. • Provided that the **distribution licensee** may act **as a RESCO**. However, this **business shall be treated as other business of the distribution licensee**	• DRES means the renewable sources or combination of such sources, such as Mini, Micro and Small Hydro, Wind, Solar, Biomass including bagasse, bio-fuel, urban or Municipal Solid Waste as recognized by the Ministry of New and Renewable Energy, Government of India;

Salient Features of Net Metering ….. (1/2)

- The prosumer may **set up distributed renewable energy system** to **offset the prosumer's electricity consumption from the distribution licensee**.
- The **distribution licensee shall** procure **any excess energy generated by PDRES at Average Power Purchase Cost for the year** in which such excess energy is procured by the distribution licensee.
- In case, the **electricity injected by the renewable energy system exceeds the electricity consumed** during the billing period, such **excess injected electricity shall be carried forward to the next billing period** as excess electricity and may be utilized in the following billing periods but within the same settlement period;
- In case, the **electricity supplied by the distribution licensee** during any billing period **exceeds the electricity injected in the grid by the PDRES,** the **distribution licensee shall raise bill for the net electricity** consumption after taking into account any excess electricity carried forward from the previous billing period;

Salient Features of Net Metering ….. (2/2)

- In case the prosumer is under the **ambit of Time of Day Tariff**, following process shall be followed:
  - **Electricity consumption in any time block** (e.g., peak hours, off-peak hours, etc.) shall be **first compensated with the electricity generation** in the **same time block**.
  - Any **excess generation over consumption** in any time block in a billing cycle shall be accounted as if the excess generation occurred during immediately lower tariff time block. This process will continue till all consumption in lower tariff blocks is set off against PDRES generation.
  - Any excess generation after setting off consumption in lower tariff time blocks would be carried forward to the next billing cycle.
- Regardless of availability of excess electricity with the prosumer during any billing period, the consumer will continue to pay all other charges such as fixed/demand charges, Government levy, etc.
- The PDRES shall be exempted from all wheeling, cross subsidy, transmission and distribution, and banking charges and surcharges.

Salient Features of Net Billing Arrangement ….. (1/2)

- The prosumer may **set up distributed renewable energy system to offset the prosumer's electricity purchase** bill from the distribution licensee.
- The **distribution licensee** shall **procure excess energy generated by PDRES** at **Average Power Purchase Cost for the year** in which such excess energy is procured by the distribution licensee.
- Net billing is the arrangement where DRE Plant is:
  - Installed to serve a specific consumer,
  - Connected on utility side on the consumer meter,
  - Selling power to distribution licensee under Power Purchase Agreement,
  - Entire power is consumed by the consumer
- The distribution licensee **shall enter into Power Purchase Agreement** at **tariff to be determined by the Commission.**
- **Entire quantum of electricity** generated by the DRE plant shall be procured by the distribution licensee.
- The distribution licensee shall enter into **Power Sale Agreement with the consumer** for sale of entire quantum of power generated by the relevant DRE plant.

Salient Features of Net Billing Arrangement ….. (2/2)

- Rate of **sell of power to the consumer** shall be the same rate as **determined by the Commission for procurement of power from DRE Plant**.
- The **distribution licensee** shall **give credit to the consumer by billing the consumer at the tariff** determined by the Commission.

$$\textit{Energy Bill of Consumer} =$$
$$\textit{Fixed charges + other applicable charges and levies} + (E_{DL} * T_{RST}) – (E_{RE} * T_{PSA}) – \textit{Billing}_{Credit}$$

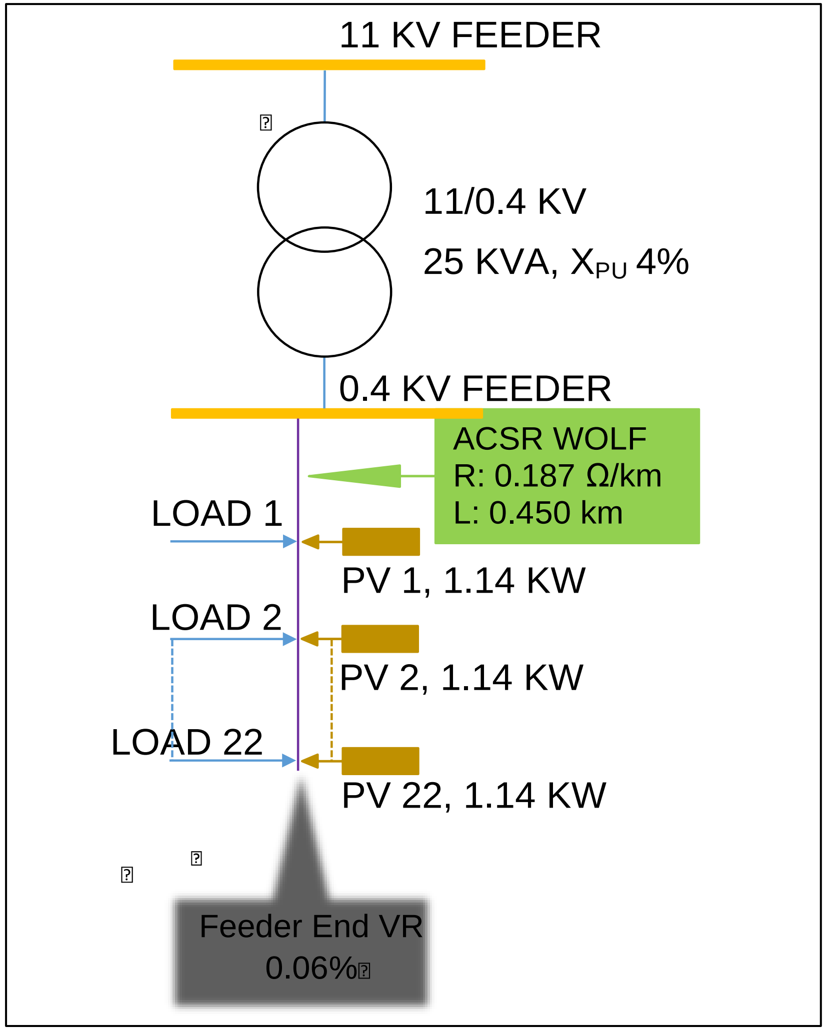
Where:

- E_{RE} means the energy units recorded for the billing period by the DRE Plant's generation meter;
- T_{PSA} means the energy charges as per the energy sale agreement signed between the consumer and distribution licensee;
- E_{DL} means the energy units supplied by the distribution licensee over and above the E_{RE} for the billing period;
- T_{RST} means the applicable retail supply tariff of the concerned consumer category as per the retail supply Tariff Order of the Commission;
- Billing credit is the amount by which value of DRE generation in a particular month is more than value of all other components of consumer bill

- In case, ($E_{RE} * T_{PSA}$) is more than (Fixed charges + other applicable charges and levies + ($E_{DL} * T_{RST}$)), utility shall give credit of amount equal to difference (Billing Credit) and the same shall be carried forward to next billing cycle.

0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

Transformer Capacity	Conditions/ Assumptions
25 KVA	▪ Case 1: Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 18 number of residential loads of 1.25 KVA capacity ▪ Case 2: Feeder Type ACSR DOG, length 0.72 km, 0.98 operating pf, 22 number of residential loads of 1.00 KVA capacity
63 KVA	▪ Case 1: Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 32 number of residential loads of 1.8 KVA capacity ▪ Case 2: Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 23 number of residential loads of 2.5 KVA capacity
100KVA	▪ Case 1: Feeder Type ACSR DOG, length 0.68 km, 0.98 operating pf, 38 number of residential loads of 2.35 KVA capacity ▪ Case 2: Feeder Type ACSR DOG, length 0.72 km, 0.98 operating pf, 46 number of residential loads of 2.00 KVA capacity



0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

INPUTS/ ASSUMPTIONS							
LV Upstream Station Data	Units	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
Enter Station Installed Capacity:	KVA	25	25	63	63	100	100
Station Primary Voltage:	V	11000	11000	11000	11000	11000	11000
Station Secondary Voltage:	V	415	415	415	415	415	415
Station Running Capacity:		90%	88%	91%	91%	89%	92%
Enter Station Overloading:		0%	0%	0%	0%	0%	0%
Safety Factor on station running capacity:		0%	0%	0%	0%	0%	0%
Margin Factor on voltage regulation:		100%	100%	100%	100%	100%	100%
Enter PV Penetration:		190%	190%	190%	190%	190%	190%
PV Installed Capacity:	KW	47.5	47.5	119.7	119.7	190	190
LV Feeder Data							
Enter Operating Power Factor:		0.98	0.98	0.98	0.98	0.98	0.98
Enter Load Quantity:		18	22	32	23	38	46
Enter Running Load:	KVA	1.25	1	1.8	2.5	2.35	2
Enter Feeder Resistance R:	Ω/km	0.279	0.279	0.279	0.279	0.279	0.279
Enter Feeder Reactance XL:	Ω/km	0	0	0	0	0	0
Enter Feeder Length:	km	0.65	0.72	0.65	0.65	0.68	0.72

0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

PV Inverter Data							
Enter Operating Power Factor:		1	1	1	1	1	1
Select Operating Mode:		Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)
OUTPUTS							
Peak PV Generation (KVA):	KVA	2.64	2.16	3.74	5.2	5	4.13
Peak PV Generation (KW):	KW	2.64	2.16	3.74	5.2	5	4.13
Peak PV Generation (KVAr):	KVAr	0	0	0	0	0	0
Running Load Consumption (W):	W	1225	980	1764	2450	2303	1960
Running Load Consumption (VAr):	VAr	249	199	358	497	468	398
Reverse Power Flow:		Yes	Yes	Yes	Yes	Yes	Yes
Reverse Active Power Flow (Pkj):	W	1414	1179	1977	2754	2697	2170
Reverse Reactive Power Flow (Qkj):	VAr	0	0	0	0	0	0
Feeder End Voltage:	V	416	416	416	416	416	416
Feeder End Voltage Rise:		0.15%	0.14%	0.21%	0.29%	0.30%	0.25%
Acceptable:		Yes	Yes	Yes	Yes	Yes	Yes
Feeder Running Load:	A	36	37	89	89	144	141
Feeder Ampacity:	A	35	35	88	88	139	139
Loading on Grid Assets:		103%	105%	102%	102%	104%	101%
Acceptable:		No	No	No	No	No	No

0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

Summary of simulation result for rural residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not more than sanctioned load/contract demand.

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	PV capacity (KW)	VR (%)	PV capacity (KW)	VR (%)	PV capacity (KW)	VR (%)
100%	50.0	Upto 0.2	126.0	Upto 0.4	200.0	Upto 0.5
90%	47.5		119.7		190.0	
80%	45.0		113.4		180.0	
70%	42.5		107.1		170.0	
60%	40.0		100.8		160.0	
50%	37.5		94.5		150.0	
40%	35.0		88.2		140.0	
30%	32.5		81.9		130.0	
20%	30.0		75.6		120.0	
10%	27.5		69.3		110.0	
0%	25.0		63.0		100.0	

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0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

Summary of simulation result for rural residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

<table>
<tr><th rowspan="3">Based on minimum DT Loading when PV Power is at Peak (noon time)</th><th colspan="6">Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)</th></tr>
<tr><th colspan="2">25 KVA</th><th colspan="2">63 KVA</th><th colspan="2">100 KVA</th></tr>
<tr><th>PV (KW)</th><th>%VR</th><th>PV (KW)</th><th>%VR</th><th>PV (KW)</th><th>%VR</th></tr>
<tr><td>100%</td><td rowspan="11">25.0</td><td rowspan="11">3.08</td><td rowspan="11">63.0</td><td rowspan="11">7.77</td><td rowspan="11">68.0</td><td rowspan="11">8.39</td></tr>
<tr><td>90%</td></tr>
<tr><td>80%</td></tr>
<tr><td>70%</td></tr>
<tr><td>60%</td></tr>
<tr><td>50%</td></tr>
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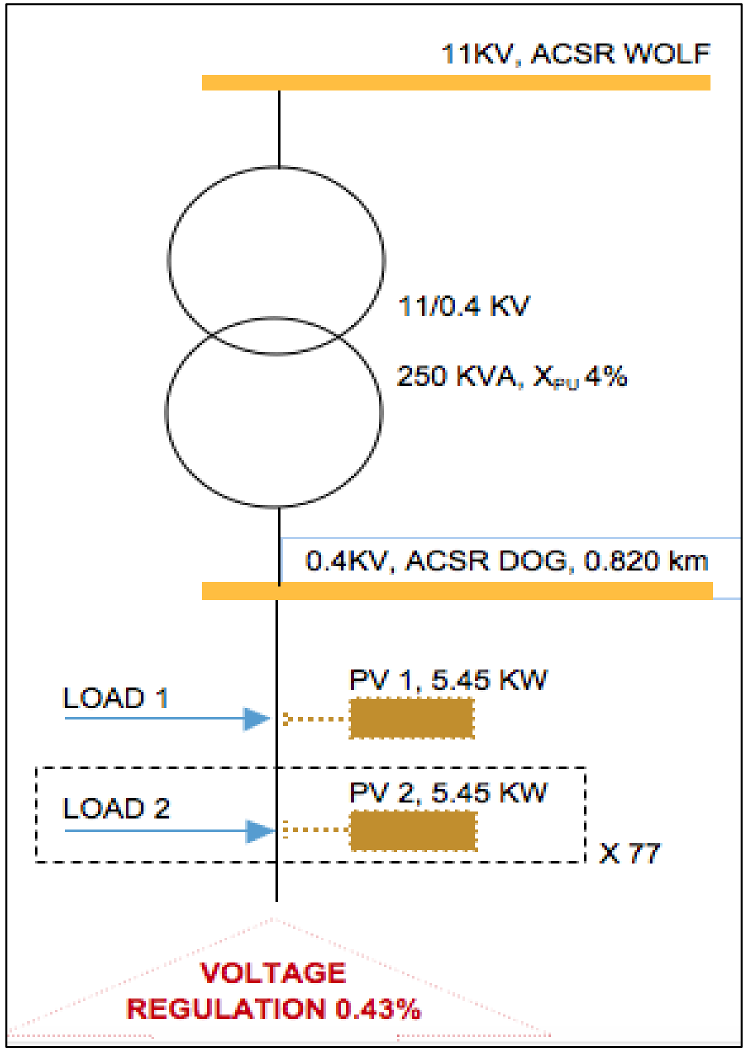
0.4KV Rural Residential Feeders with 25KVA, 63KVA & 100KVA DT

Summary of simulation result for rural residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
850	25.0	3.08	63.0	7.77	68.0	8.39
800	25.0	2.90	63.0	7.32	73.0	8.42
750	25.0	2.72	63.0	6.86	77.0	8.38
700	25.0	2.54	63.0	6.40	83.0	8.38
650	25.0	2.36	63.0	5.94	89.0	8.40
600	25.0	2.18	63.0	5.49	97.0	8.41
550	25.0	2.03	63.0	5.03	100.0	7.98
500	25.0	1.84	63.0	4.57	100.0	7.26
450	25.0	1.66	63.0	4.12	100.0	6.53
400	25.0	1.47	63.0	3.66	100.0	5.81
350	25.0	1.28	63.0	3.20	100.0	5.08

0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

Transformer Capacity	Conditions/ Assumptions
250KVA	▪ **Case 1:** Feeder Type ACSR DOG, length 0.85 km, 0.98 operating pf,65 number of residential loads of 2.75 KVA capacity ▪ **Case 2:** Feeder Type ACSR DOG, length 0.82 km, 0.98 operating pf, 78 number of residential loads of 2.25 KVA capacity
400KVA	▪ **Case 1:** Feeder Type ACSR DOG, length 0.83 km, 0.98 operating pf, 68 number of residential loads of 4.15 KVA capacity ▪ **Case 2:** Feeder Type ACSR DOG, length 0.86 km, 0.98 operating pf, 76 number of residential loads of 3.65 KVA capacity
630KVA	▪ **Case 1:** Feeder Type ACSR DOG, length 0.92 km, 0.98 operating pf, 86 number of residential loads of 5.15 KVA capacity ▪ **Case 2:** Feeder Type ACSR DOG, length 0.72 km, 0.88 operating pf, 72 number of residential loads of 6.15 KVA capacity



0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

INPUTS/ ASSUMPTIONS							
LV Upstream Station Data	**Units**	**Case 1**	**Case 2**	**Case 1**	**Case 2**	**Case 1**	**Case 2**
Enter Station Installed Capacity:	KVA	250	250	400	400	630	630
Station Primary Voltage:	V	11000	11000	11000	11000	11000	11000
Station Secondary Voltage:	V	415	415	415	415	415	415
Station Running Capacity:		72%	70%	71%	69%	70%	70%
Enter Station Overloading:		0%	0%	0%	0%	0%	0%
Safety Factor on station running capacity:		0%	0%	0%	0%	0%	0%
Margin Factor on voltage regulation:		100%	100%	100%	100%	100%	100%
Enter PV Penetration:		170%	170%	170%	170%	170%	170%
PV Installed Capacity:	KW	425	425	680	680	1071	1071
LV Feeder Data							
Enter Operating Power Factor:		0.98	0.98	0.98	0.98	0.98	0.98
Enter Load Quantity:		65	78	68	76	86	72
Enter Running Load:	KVA	2.75	2.25	4.15	3.65	5.15	6.15
Enter Feeder Resistance - R:	Ω/km	0.279	0.279	0.279	0.279	0.279	0.279
Enter Feeder Reactance - XL:	Ω/km	0	0	0	0	0	0
Enter Feeder Length:	km	0.85	0.82	0.83	0.86	0.92	0.88

0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

PV Inverter Data							
Enter Operating Power Factor:		1	1	1	1	1	1
Select Operating Mode:		Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)
OUTPUTS							
Peak PV Generation (KVA):	KVA	6.54	5.45	10	8.95	12.45	14.88
Peak PV Generation (KW):	KW	6.54	5.45	10	8.95	12.45	14.88
Peak PV Generation (KVAr):	KVAr	0	0	0	0	0	0
Running Load Consumption (W):	W	2695	2205	4067	3577	5047	6027
Running Load Consumption (VAr):	VAr	547	448	826	726	1025	1224
Reverse Power Flow:		Yes	Yes	Yes	Yes	Yes	Yes
Reverse Active Power Flow (Pkj):	W	3843	3244	5933	5370	7406	8848
Reverse Reactive Power Flow (Qkj):	VAr	0	0	0	0	0	0
Feeder End Voltage:	V	417	417	418	418	420	420
Feeder End Voltage Rise:		0.53%	0.43%	0.80%	0.75%	1.10%	1.26%
Acceptable:		Yes	Yes	Yes	Yes	Yes	Yes
Feeder Running Load:	A	349	354	562	569	885	884
Feeder Ampacity:	A	348	348	557	557	876	876
Loading on Grid Assets:		100%	102%	101%	102%	101%	101%
Acceptable:		No	No	No	No	No	No

0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

Summary of simulation result for urban residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not more than sanctioned load/contract demand.

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250KVA		400KVA		630KVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
100%	500.0	Upto 0.7	800.0	Upto 0.9	1260.0	Upto 1.5
90%	475.0		760.0		1197.0	
80%	450.0		720.0		1134.0	
70%	425.0		680.0		1071.0	
60%	400.0		640.0		1008.0	
50%	375.0		600.0		945.0	
40%	350.0		560.0		882.0	
30%	325.0		520.0		819.0	
20%	300.0		480.0		756.0	
10%	275.0		440.0		693.0	
0%	250.0		400.0		630.0	

0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

Summary of simulation result for urban residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

<table>
<tr><th rowspan="3">Based on minimum DT Loading when PV Power is at Peak (noon time)</th><th colspan="6">Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)</th></tr>
<tr><th colspan="2">250 KVA</th><th colspan="2">400 KVA</th><th colspan="2">630 KVA</th></tr>
<tr><th>PV (KW)</th><th>%VR</th><th>PV (KW)</th><th>%VR</th><th>PV (KW)</th><th>%VR</th></tr>
<tr><td>100%</td><td rowspan="11">68.0</td><td rowspan="11">8.33</td><td rowspan="11">68.0</td><td rowspan="11">8.39</td><td rowspan="11">66.0</td><td rowspan="11">8.16</td></tr>
<tr><td>90%</td></tr>
<tr><td>80%</td></tr>
<tr><td>70%</td></tr>
<tr><td>60%</td></tr>
<tr><td>50%</td></tr>
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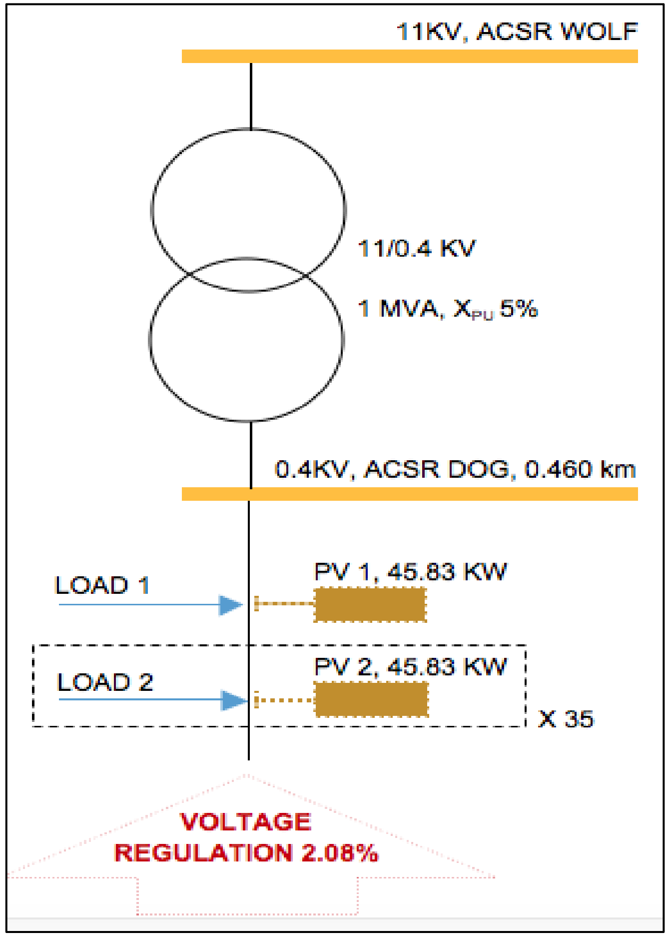
0.4KV Urban Residential Feeders – 250KVA, 400KVA & 630KVA DT

Summary of simulation result for urban residential feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250 KVA		400 KVA		630 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
850	68.0	8.33	68.0	8.39	66.0	8.16
800	73.0	8.42	72.0	8.36	72.0	8.41
750	76.0	8.30	76.0	8.27	76.0	8.23
700	83.0	8.38	82.0	8.33	82.0	8.32
650	89.0	8.37	88.0	8.30	88.0	8.32
600	96.0	8.38	96.0	8.36	95.0	8.23
550	105.0	8.38	104.0	8.30	104.0	8.30
500	115.0	8.35	116.0	8.42	113.0	8.23
450	129.0	8.41	128.0	8.36	126.0	8.23
400	145.0	8.42	144.0	8.36	145.0	8.41
350	165.0	8.38	164.0	8.33	164.0	8.32

0.4KV Urban Commercial Feeders – 1MVA & 1.25MVA DT

Transformer Capacity	Conditions/ Assumptions
1MVA	• **Case 1:** Feeder Type ACSR DOG, length 0.46 km, 0.98 operating pf, 36 number of Commercial loads of 18.25 KVA capacity • **Case 2:** Feeder Type ACSR DOG, length 0.42 km, 0.98 operating pf, 30 number of Commercial loads of 21.5 KVA capacity
1.25MVA	• **Case 1:** Feeder Type ACSR DOG, length 0.52 km, 0.98 operating pf, 36 number of Commercial loads of 22.50 KVA capacity • **Case 2:** Feeder Type ACSR DOG, length 0.56 km, 0.98 operating pf, 41 number of Commercial loads of 20.00 KVA capacity



0.4KV Urban Commercial Feeders – 1MVA and 1.25MVA DT

INPUTS/ ASSUMPTIONS					
LV Upstream Station Data	**Units**	**Case 1**	**Case 2**	**Case 1**	**Case 2**
Enter Station Installed Capacity:	KVA	1000	1000	1250	1250
Station Primary Voltage:	V	11000	11000	11000	11000
Station Secondary Voltage:	V	415	415	415	415
Station Running Capacity:		65.70%	64.50%	64.80%	65.60%
Enter Station Overloading:		0.00%	0.00%	0.00%	0.00%
Safety Factor on station running capacity:		0.00%	0.00%	0.00%	0.00%
Margin Factor on voltage regulation:		100.00%	100.00%	100.00%	100.00%
Enter PV Penetration:		165.00%	165.00%	165.00%	165.00%
PV Installed Capacity:	KW	1650	1650	2062.5	2062.5
LV Feeder Data					
Enter Operating Power Factor:		0.98	0.98	0.98	0.98
Enter Load Quantity:		36	30	36	41
Enter Running Load:	KVA	18.25	21.5	22.5	20
Enter Feeder Resistance R:	Ω/km	0.279	0.279	0.279	0.279
Enter Feeder Reactance XL:	Ω/km	0	0	0	0
Enter Feeder Length:	km	0.46	0.42	0.52	0.56

0.4KV Urban Commercial Feeders – 1MVA and 1.25MVA DT

PV Inverter Data					
Enter Operating Power Factor:		1	1	1	1
Select Operating Mode:		Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)
OUTPUTS					
Peak PV Generation (KVA):	KVA	45.83	55	57.29	50.3
Peak PV Generation (KW):	KW	45.83	55	57.29	50.3
Peak PV Generation (KVAr):	KVAr	0	0	0	0
Running Load Consumption (W):	W	17885	21070	22050	19600
Running Load Consumption (VAr):	VAr	3632	4278	4477	3980
Reverse Power Flow:		Yes	Yes	Yes	Yes
Reverse Active Power Flow (Pkj):	W	27948.3	33930	35241.7	30704.9
Reverse Reactive Power Flow (Qkj):	VAr	0	0	0	0
Feeder End Voltage:	V	424	425	427	427
Feeder End Voltage Rise:		2.08%	2.31%	2.97%	2.79%
Acceptable:		Yes	Yes	Yes	Yes
Feeder Running Load:	A	1383	1395	1728	1718
Feeder Ampacity:	A	1391	1391	1739	1739
Loading on Grid Assets:		99.39%	100.28%	99.36%	98.80%
Acceptable:		Yes	No	Yes	Yes

0.4KV Urban Commercial Feeders – 1MVA and 1.25MVA DT

Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not more than sanctioned load/contract demand.

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
100%	2000.0	Upto 2.5	2500.0	Upto 3.0
90%	1900.0		2375.0	
80%	1800.0		2250.0	
70%	1700.0		2125.0	
60%	1600.0		2000.0	
50%	1500.0		1875.0	
40%	1400.0		1750.0	
30%	1300.0		1625.0	
20%	1200.0		1500.0	
10%	1100.0		1375.0	
0%	1000.0		1250.0	

0.4KV Urban Commercial Feeders – 1MVA and 1.25MVA DT

Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Based on minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV (KW)	%VR	PV (KW)	%VR
100%	68.0	8.02	68.0	7.71
90%				
80%				
70%				
60%				
50%				
40%				
30%				
20%				
10%				
0%				

0.4KV Urban Commercial Feeders – 1MVA and 1.25MVA DT

Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV (KW)	%VR	PV (KW)	%VR
850	65.0	8.02	63.0	7.71
800	70.0	8.13	69.0	7.98
750	75.0	8.17	75.0	8.17
700	80.0	8.13	81.0	8.26
650	85.0	8.02	88.0	8.26
600	95.0	8.27	94.0	8.17
550	105.0	8.38	100.0	7.98
500	115.0	8.35	113.0	8.17
450	125.0	8.17	125.0	8.17
400	145.0	8.42	144.0	8.35
350	165.0	8.38	163.0	8.26

Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	63.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.17%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	63.00	KW

LV Feeder Data

Enter Operating Power Fac	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.11	KVA
Enter Feeder Resistance R	0.250	Ω/km
Enter Feeder Reactance X	0.050	Ω/km
Enter Feeder Length:	0.100	km

PV Inverter Data

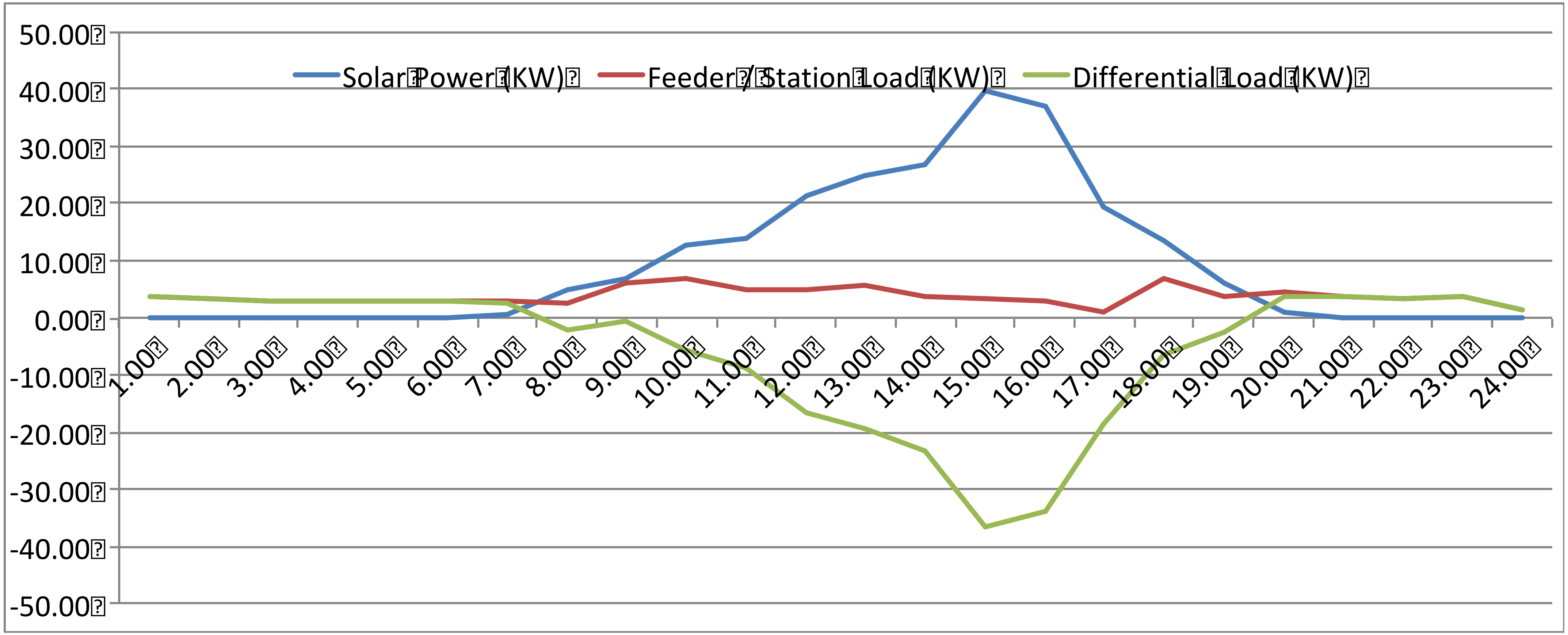
Operating Power Facto	1.00
Select Operating Mod	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	63.00	KVA
Peak PV Generation (KW):	63.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	107.80	W
Running Load Consumption (VAr):	21.89	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	62892.20	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	418.79	V
Feeder End Voltage Rise:	0.91%	
Acceptable:	Yes	
Feeder Running Load:	86.71	A
Feeder Ampacity:	87.65	A
Loading on Grid Assets:	98.93%	
Acceptable:	Yes	

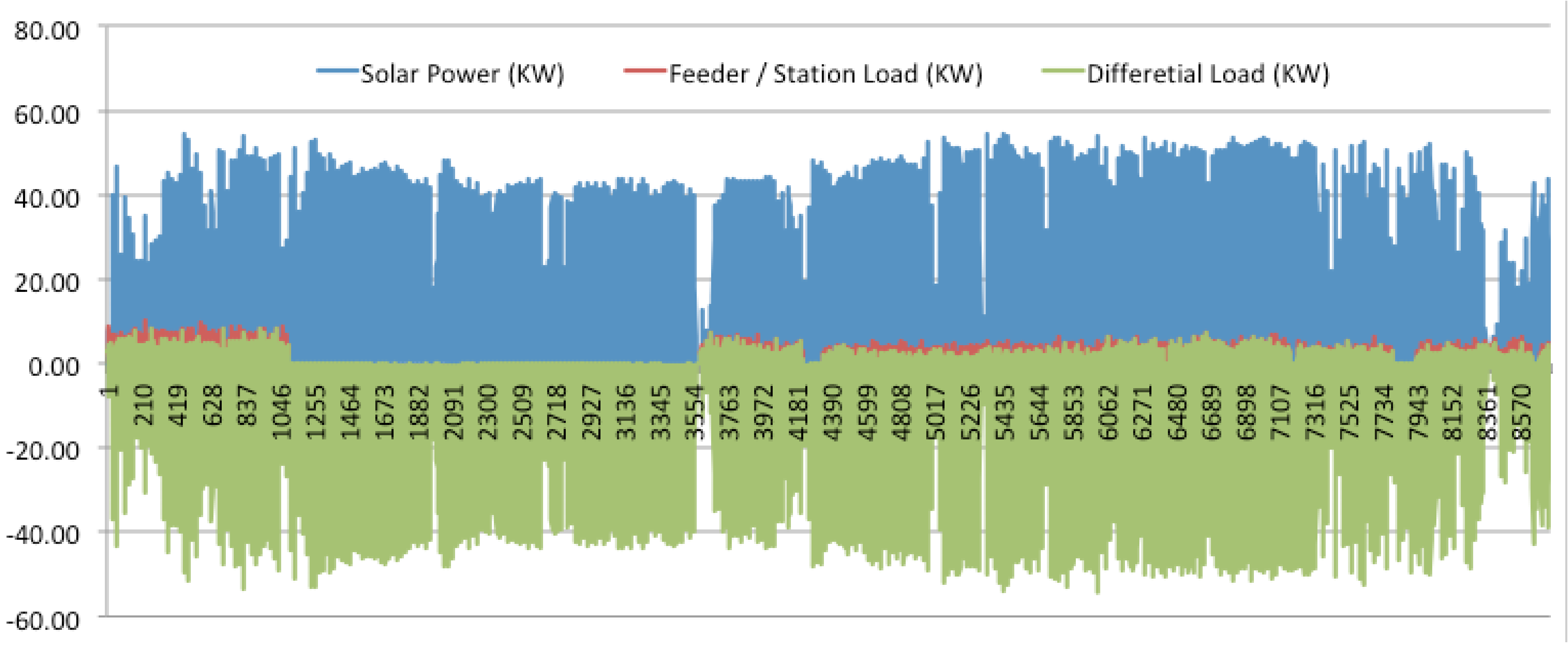
Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case Study 1: 0.4KV Feeder and 63KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.02%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	100.00	KW

LV Feeder Data

Enter Operating Power Factor	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.02	KVA
Enter Feeder Resistance - R:	0.150	Ω/km
Enter Feeder Reactance - X_L:	0.075	Ω/km
Enter Feeder Length:	0.350	km

PV Inverter Data

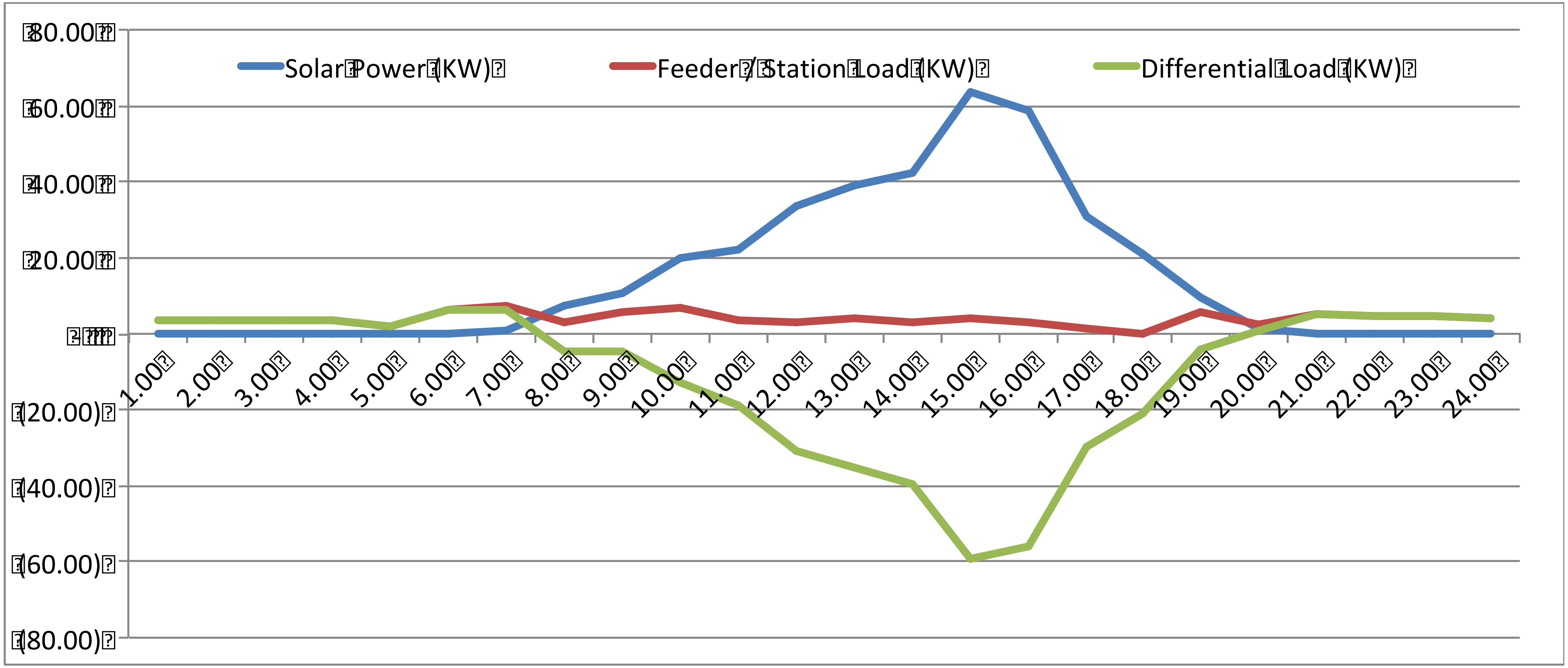
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	100.00	KVA
Peak PV Generation (KW):	100.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	23.52	W
Running Load Consumption (VAr):	4.78	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	99976.48	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	427.65	V
Feeder End Voltage Rise:	3.05%	
Acceptable:	Yes	
Feeder Running Load:	134.98	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	97.02%	
Acceptable:	Yes	

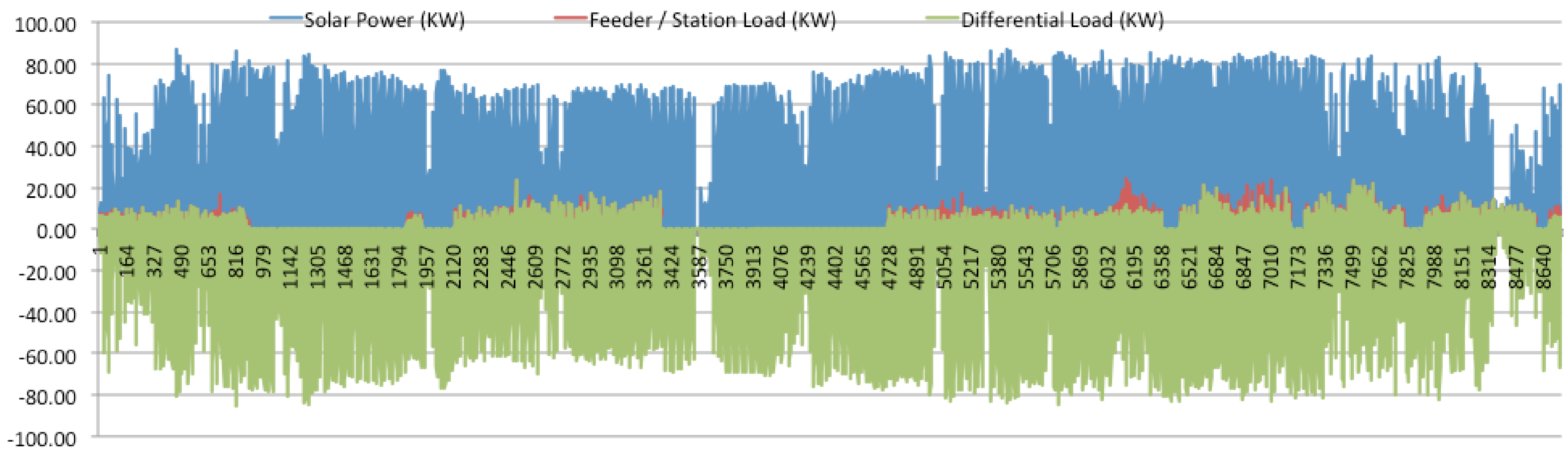
Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	1.56%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	101.00%	
PV Installed Capacity:	101.00	KW

LV Feeder Data

Enter Operating Power Factor	0.98	
Enter Load Quantity:	26	
Enter Running Load:	0.06	KVA
Enter Feeder Resistance - R:	0.279	Ω/km
Enter Feeder Reactance - X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

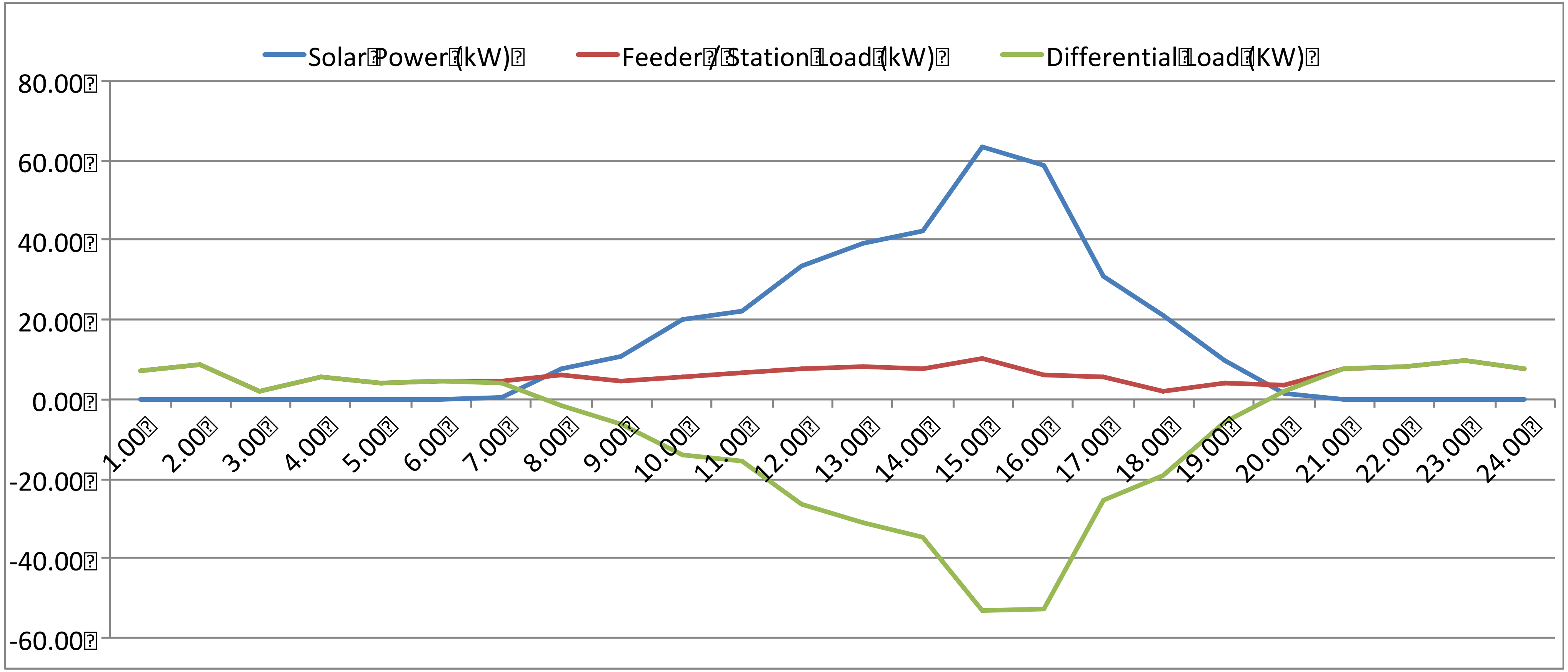
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	3.88	KVA
Peak PV Generation (KW):	3.88	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	58.80	W
Running Load Consumption (VAr):	11.94	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	3825.82	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	416.16	V
Feeder End Voltage Rise:	0.28%	
Acceptable:	Yes	
Feeder Running Load:	138.00	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	99.20%	
Acceptable:	Yes	

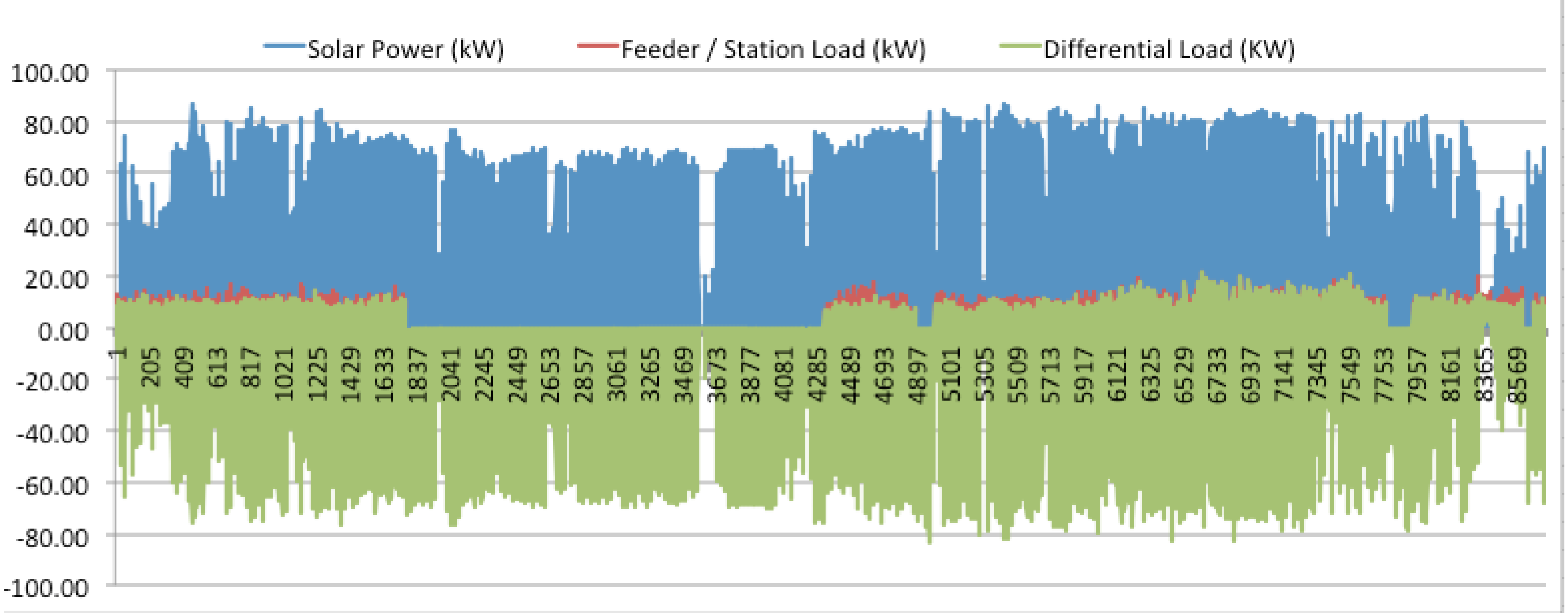
Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



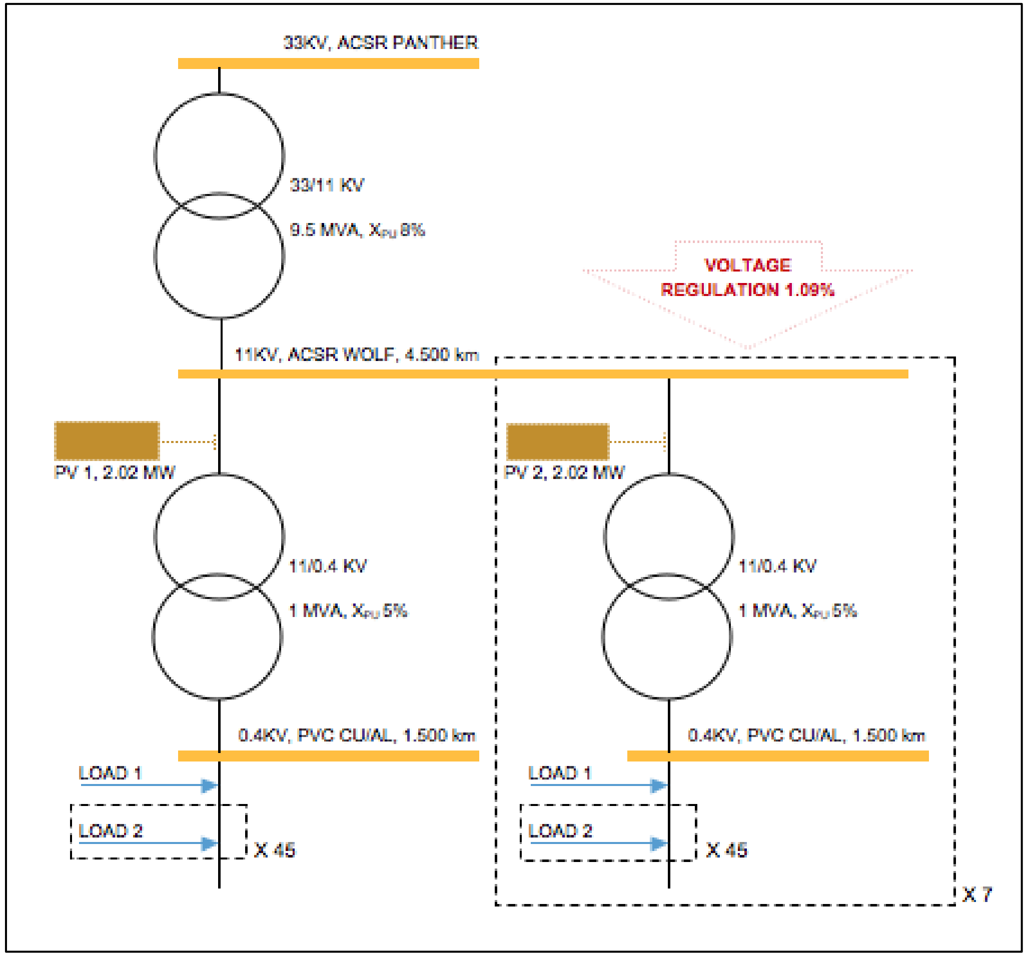
Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

Transformer Capacity	Conditions/ Assumptions
9.5MVA	· **Case 1**: Feeder Type ACSR WOLF, length 4.5 km, 46 number of industrial loads of 18.00 KVA capacity · **Case 2**: Feeder Type ACSR WOLF, length 4.8 km, 32 number of industrial loads of 15.00 KVA capacity
12.5MVA	· **Case 1**: Feeder Type ACSR WOLF, length 4.7 km, 52 number of industrial loads of 32.50 KVA capacity · **Case 2**: Feeder Type ACSR WOLF, length 4.75 km, 58 number of industrial loads of 21.50 KVA capacity
15MVA	· **Case 1**: Feeder Type ACSR WOLF, length 5.25 km, 42 number of industrial loads of 52.50 KVA capacity · **Case 2**: Feeder Type ACSR WOLF, length 5.5 km, 58 number of industrial loads of 22.50 KVA capacity
16.5MVA	· **Case 1**: Feeder Type ACSR WOLF, length 5.75 km, 56 number of industrial loads of 46.50 KVA capacity · **Case 2**: Feeder Type ACSR WOLF, length 6.35 km, 38 number of industrial loads of 34.50 KVA capacity



11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

INPUTS/ASSUMPTIONS									
MV Upstream Station Data	**Units**	**Case 1**	**Case 2**	**Case 1**	**Case 2**	**Case 1**	**Case 2**	**Case 1**	**Case 2**
Enter Station Installed Capacity:	KVA	9500	9500	12500	12500	15000	15000	16500	16500
Station Primary Voltage:	V	33000	33000	33000	33000	33000	33000	33000	33000
Station Secondary Voltage:	V	11000	11000	11000	11000	11000	11000	11000	11000
Station Running Capacity:		70%	71%	81%	80%	59%	61%	79%	79%
Enter Station Overloading:		0%	0%	0%	0%	0%	0%	0%	0%
Safety Factor (on station running capacity):		0%	0%	0%	0%	0%	0%	0%	0%
Margin Factor (on voltage regulation):		100%	100%	100%	100%	100%	100%	100%	100%
Enter PV Penetration:		170%	170%	180%	180%	160%	160%	180%	180%
PV Installed Capacity:	KW	16150	16150	22500	22500	24000	24000	29700	29700
LV Feeder Data									
Enter Operating Power Factor:		0.86	0.86	0.86	0.86	0.87	0.87	0.86	0.86
Enter Load Quantity:		46	32	52	58	42	58	56	38
Enter Running Load:	KVA	18	15	32.5	21.5	52.5	22.5	46.5	34.5
Enter Feeder Resistance – R:	Ω/km	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Enter Feeder Reactance – XL:	Ω/km	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Enter Feeder Length:	km	1.5	1.2	1.8	1.75	2.5	2.75	2.85	3.85

11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

LV Upstream Station Data									
Enter Station Quantity		8	14	6	8	4	7	5	10
Enter Station Installed Capacity	KVA	1000	1000	2500	2500	3750	3750	4000	4000
Station Primary Voltage	V	11000	11000	11000	11000	11000	11000	11000	11000
Station Secondary Voltage	V	415	415	415	415	415	415	415	415
Station Running Capacity		83%	48%	68%	50%	59%	35%	65%	33%
Station Running Capacity	KVA	828	480	1690	1247	2205	1305	2604	1311
Enter Station Per Unit Reactance XPU		5%	5%	6%	6%	7%	7%	7%	7%
Station Base Reactance XBASE	Ω	146	252	72	97	55	93	46	92
Station Actual Reactance	Ω	7.31	12.6	4.3	5.82	3.84	6.49	3.25	6.46
MV Feeder Data									
Operating Power Factor		0.83	0.83	0.83	0.83	0.83	0.83	0.82	0.82
Enter Adjusted Power Factor		0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Enter Feeder Resistance R:	Ω/km	0.187	0.187	0.187	0.187	0.187	0.187	0.187	0.187
Enter Feeder Reactance XL:	Ω/km	0	0	0	0	0	0	0	0
Enter Feeder Length:	km	4.5	4.8	4.75	4.75	5.25	5.5	5.75	6.35
PV Inverter Data									
Enter Operating Power Factor:		1	1	1	1	1	1	1	1
Select Operating Mode:		Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)

11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

OUTPUTS									
Peak PV Generation (KVA):	KVA	2019	1154	3750	2813	6000	3429	5940	2970
Peak PV Generation (KW):	KW	2019	1154	3750	2813	6000	3429	5940	2970
Peak PV Generation (KVAr):	KVAr	0	0	0	0	0	0	0	0
Running Load Consumption (W):	W	811440	470400	1656200	1222060	2160900	1278900	2551920	1284780
Running Load Consumption (VAr):	VAr	164770	95519	336306	248150	438789	259692	518189	260886
Reverse Power Flow:		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Reverse Active Power Flow (Pkj):	W	1207310	683171	2093800	1590440	3839100	2149671	3388080	1685220
Reverse Reactive Power Flow (Qkj):	VAr	0	0	0	0	0	0	0	0
Feeder End Voltage:	V	11120	11069	11236	11176	11462	11279	11492	11293
Feeder End Voltage Rise:		1.09%	0.62%	2.14%	1.60%	4.20%	2.54%	4.47%	2.66%
Acceptable:		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Feeder Running Load:	A	506	504	654	665	779	776	861	872
Feeder Ampacity:	A	499	499	656	656	787	787	866	866
Loading on Grid Assets:		102%	101%	100%	101%	99%	99%	99%	101%
Acceptable:		No	No	Yes	No	Yes	Yes	Yes	No

11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

Summary of simulation result for 11KV feeder with distributed PV Plants when permitted individual PV capacity is not more than sanctioned load/contract demand.

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)							
	9.5 MVA		12.5 MVA		15 MVA		16.5 MVA	
	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)
100%	19.0	Upto 1.5	25.0	Upto 2.5	30.0	Upto 4.5	33.0	Upto 5.0
90%	18.1		23.8		28.5		31.4	
80%	17.1		22.5		27.0		29.7	
70%	16.2		21.3		25.5		28.1	
60%	15.2		20.0		24.0		26.4	
50%	14.3		18.8		22.5		24.8	
40%	13.3		17.5		21.0		23.1	
30%	12.4		16.3		19.5		21.5	
20%	11.4		15.0		18.0		19.8	
10%	10.5		13.8		16.5		18.2	
0%	9.5		12.5		15.0		16.5	

11KV Feeders – 9.5MVA, 12.5MVA, 15MVA and 16.5MVA station

Summary of simulation result for 11KV with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Feeder length (m) when PV power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)							
	9.5 MVA		12.5 MVA		15 MVA		16.5 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
6500	9.0	9.07	9.0	9.04	9.0	9.04	9.0	9.03
6000	9.5	8.81	9.8	9.04	9.8	9.04	9.7	9.03
5500	9.5	8.07	10.7	9.08	10.7	9.05	10.6	9.05
5000	9.5	7.34	11.8	9.08	11.7	9.04	11.7	9.05
4500	9.5	6.61	12.5	8.69	13.1	9.08	13.0	9.07
4000	9.5	5.87	12.5	7.73	14.7	9.08	14.7	9.08
3500	9.5	5.14	12.5	6.76	15.0	8.11	16.5	8.92
3000	9.5	4.40	12.5	5.80	15.0	6.95	16.5	7.65
2500	9.5	3.67	12.5	4.83	15.0	5.80	16.5	6.38
2000	9.5	2.94	12.5	3.86	15.0	4.64	16.5	5.10
1500	9.5	2.21	12.5	2.90	15.0	3.48	16.5	3.83

Case study 4: 11KV feeder and 115KVA station at Ranchi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	115.00	KW

OUTPUTS

Peak PV Generation (KVA):	115.00	KVA
Peak PV Generation (KW):	115.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.31	W
Running Load Consumption (VAr):	0.92	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	114998.69	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11000.88	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	6.04	A
Feeder Ampacity:	6.04	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	16	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	0.650	km

LV Upstream Station Data

Enter Station Quantity:	1	
Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Station Per Unit Reactance – X_{PU}:	7.00%	
Station Base Reactance – X_{BASE}:	75625000	Ω
Station Actual Reactance – X_{Ω}:	5293750	Ω

MV Feeder Data

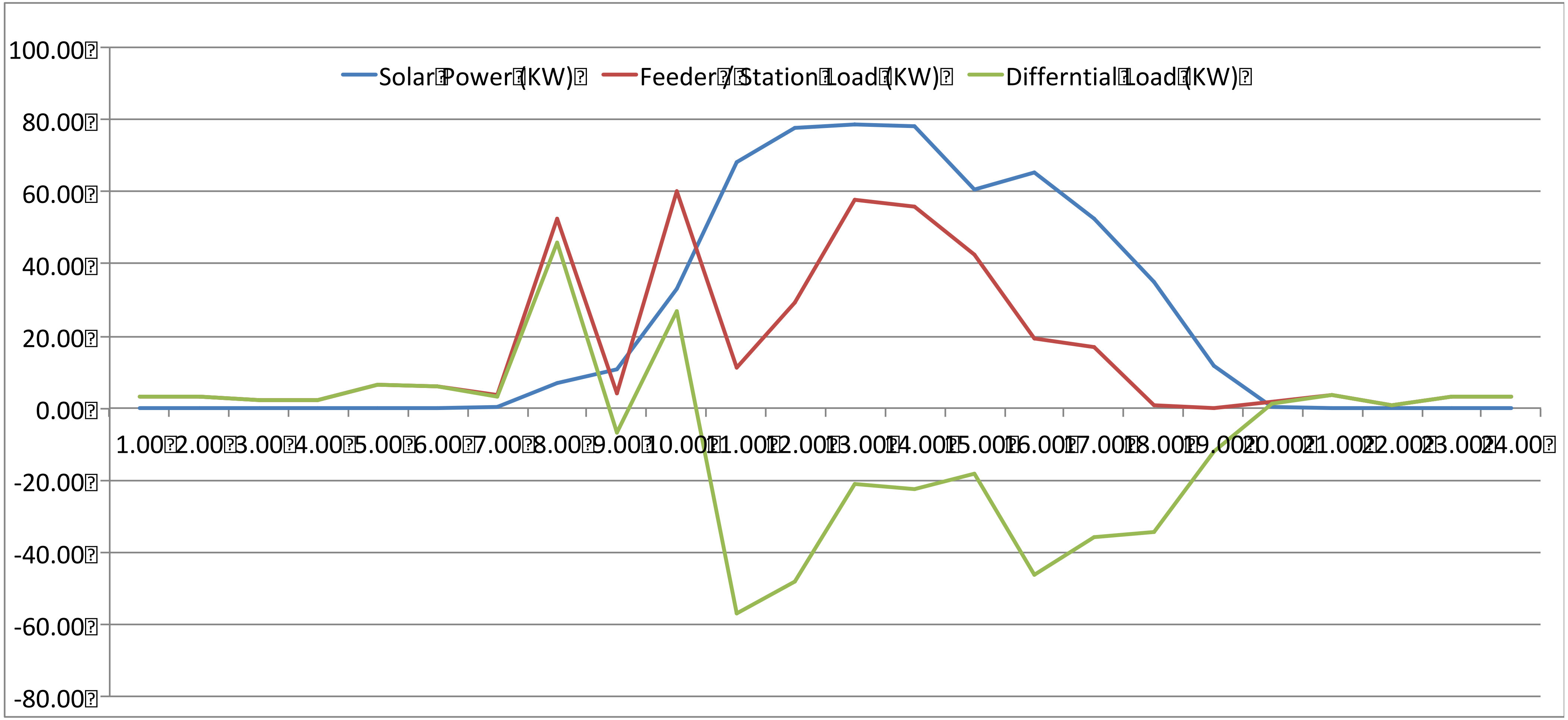
Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.82	
Enter Feeder Resistance – R:	0.187	Ω/km
Enter Feeder Reactance – X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	verexcited (lea

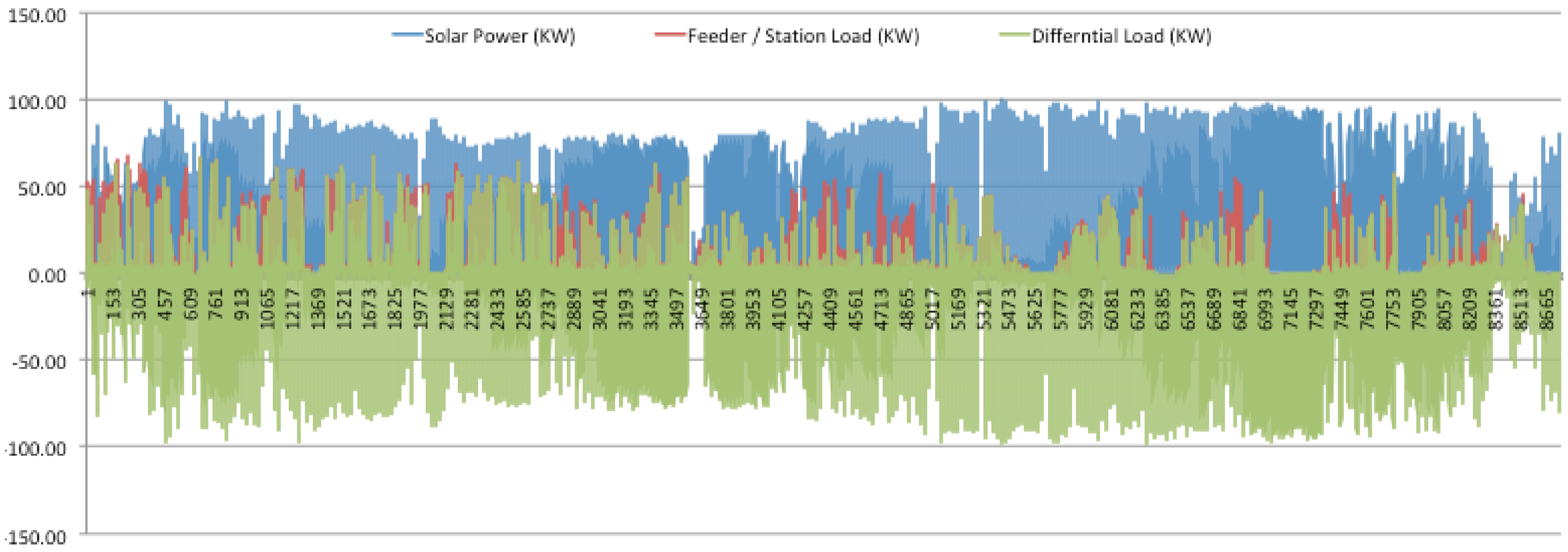
Case study 4: 11KV feeder and 115KVA station at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 4: 11KV feeder and 115KVA station at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 5: 11KV feeder and 140KVA station at Ranchi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	140.00	KW

OUTPUTS

Peak PV Generation (KVA):	140.00	KVA
Peak PV Generation (KW):	140.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.76	W
Running Load Consumption (VAr):	0.36	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	139998	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11001.07	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	7.35	A
Feeder Ampacity:	7.35	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	18	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance - R:	0.350	Ω/km
Enter Feeder Reactance - X_L:	0.015	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Enter Station Per Unit Reactance - X_{PU}:	7.00%	
Station Base Reactance - X_{BASE}:	67222222	Ω
Station Actual Reactance - X_{Ω}:	4705556	Ω

MV Feeder Data

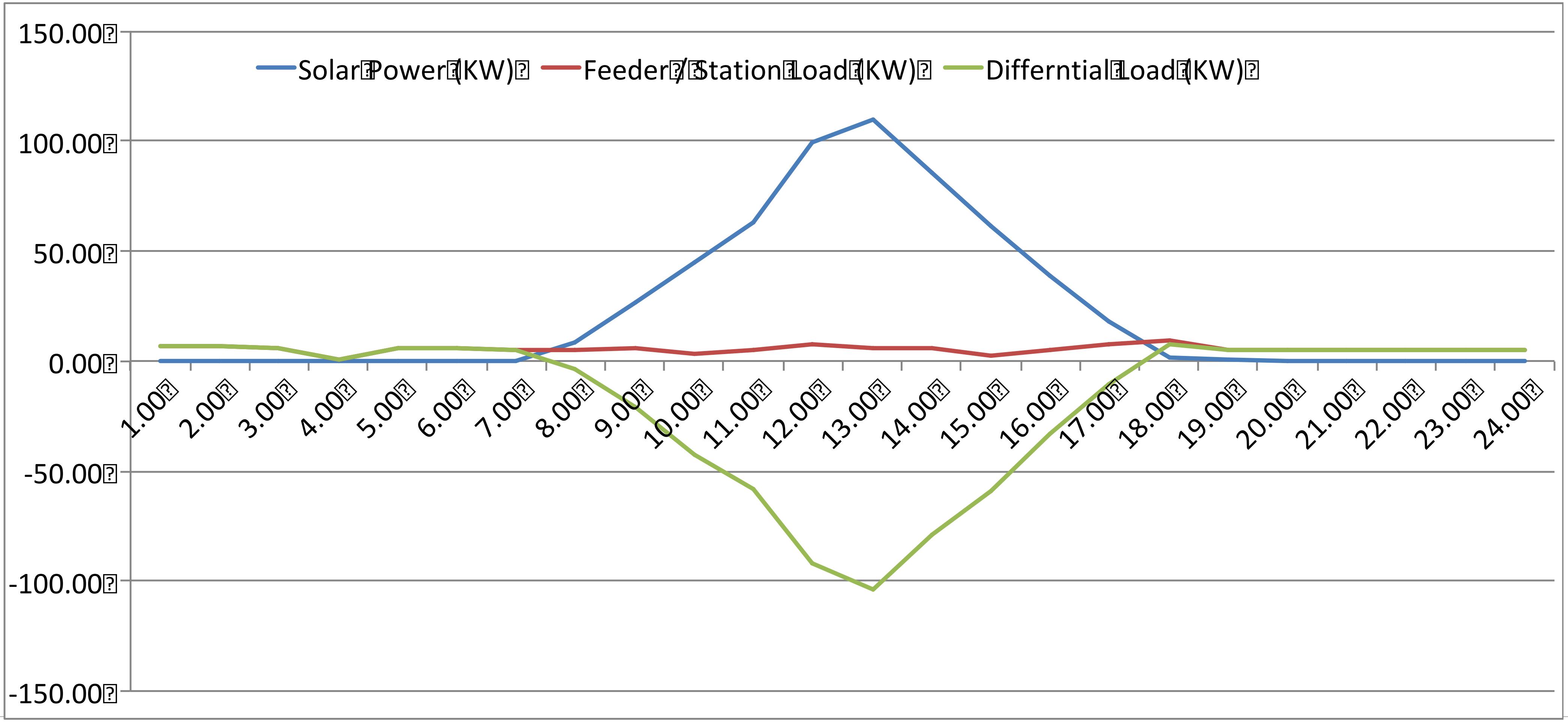
Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.98	
Enter Feeder Resistance - R:	0.187	Ω/km
Enter Feeder Reactance - X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

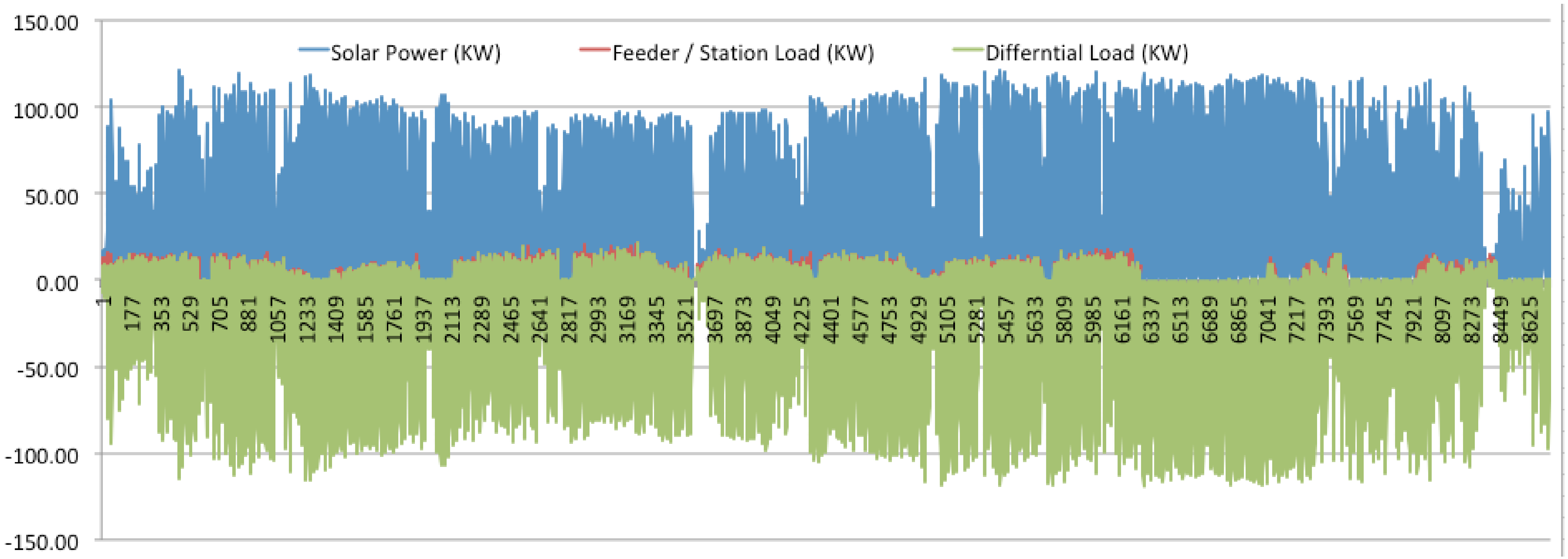
Case study 5: 11KV feeder and 140KVA station at Ranchi

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 5: 11KV feeder and 140KVA station at Ranchi

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 6: 11KV feeder and 630KVA station at Delhi

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	630.00	KVA
Station Primary Voltage:	33000	V
Station Secondary Voltage:	11000	V
Station Running Capacity:	12.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100%	
Enter PV Penetration:	112%	
PV Installed Capacity:	705.60	KW

LV Feeder Data

Enter Operating Power Factor:	0.96	
Enter Load Quantity:	62	
Enter Running Load:	1.26	KVA
Enter Feeder Resistance – R:	0.350	Ω/km
Enter Feeder Reactance – X_L:	0.015	Ω/km
Enter Feeder Length:	0.750	km

MV Feeder Data

Operating Power Factor:	0.94	
Enter Adjusted Power Factor	0.98	
Enter Feeder Resistance – R:	0.150	Ω/km
Enter Feeder Reactance – X_L:	0.100	Ω/km
Enter Feeder Length:	0.750	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

LV Upstream Station Data

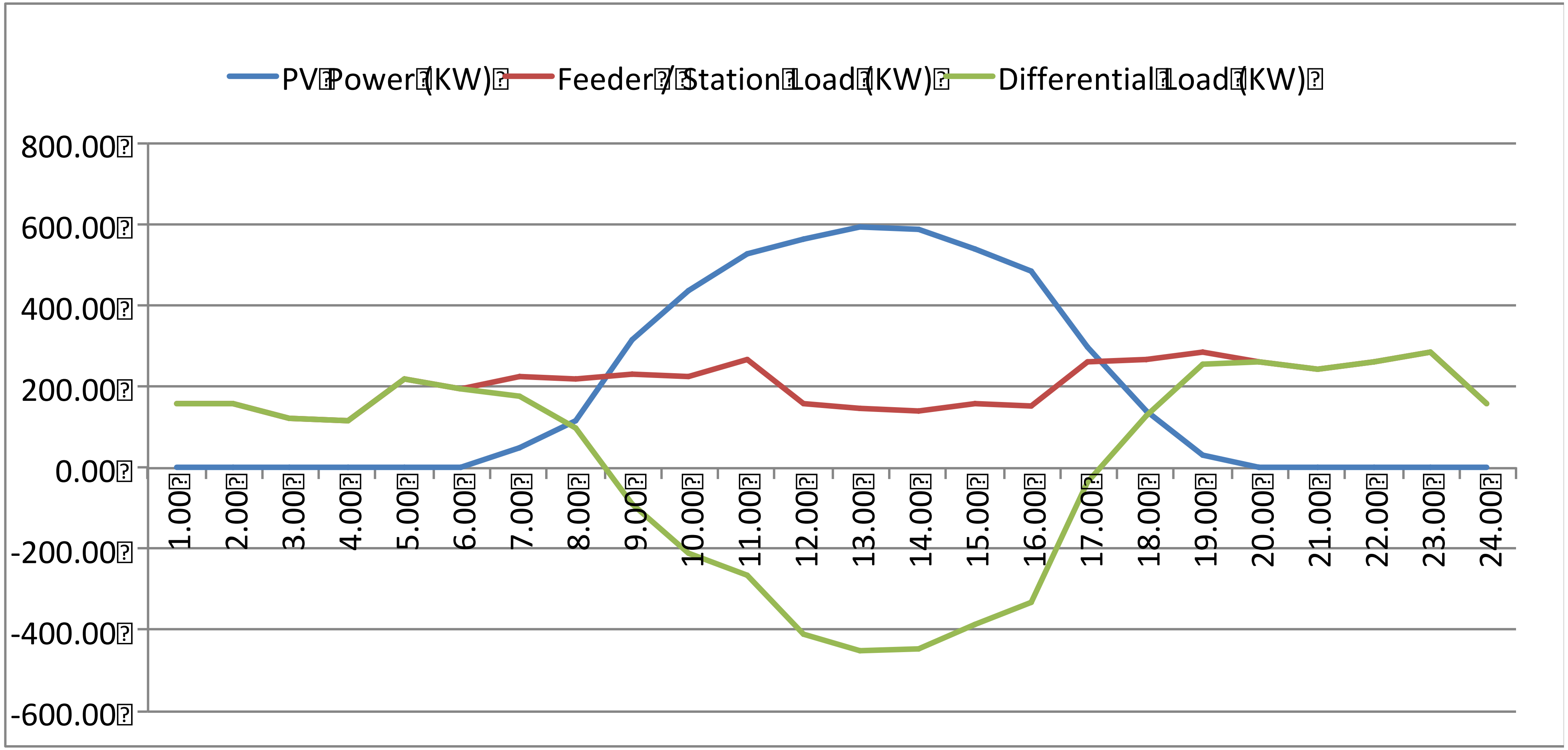
Enter Station Quantity:	1	
Station Installed Capacity:	630	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	12.41%	
Station Running Capacity:	78.18	KVA
Station Per Unit Reactance – X_{PU}:	6.00%	
Station Base Reactance – X_{BASE}:	1548	Ω
Station Actual Reactance – X_{Ω}:	92.86	Ω

OUTPUTS

Peak PV Generation (KVA):	706	KVA
Peak PV Generation (KW):	706	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	76618	W
Running Load Consumption (VAr):	15558	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	628982	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11008	V
Feeder End Voltage Rise:	0.08%	
Acceptable:	Yes	
Feeder Running Load:	33.00	A
Feeder Ampacity:	33.07	A
Loading of Grid Assets:	99.79%	
Acceptable:	Yes	

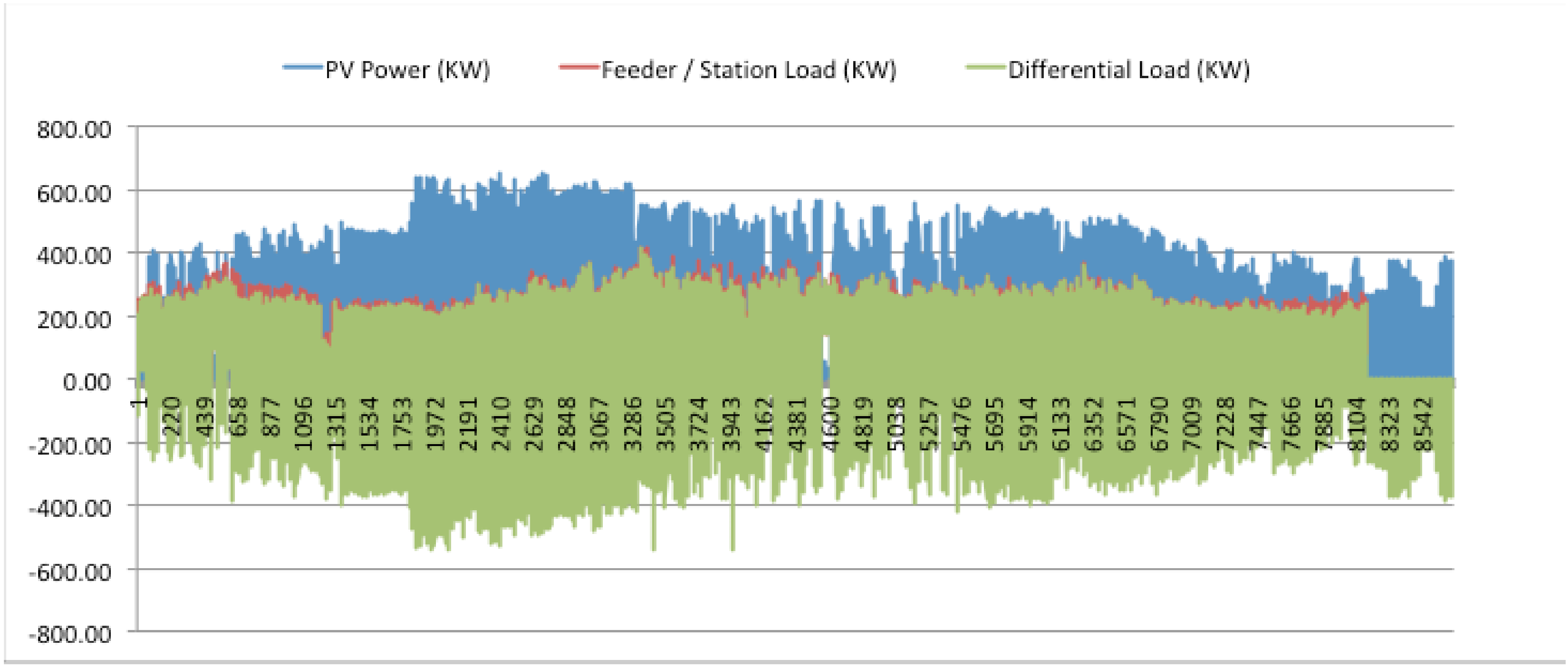
Case study 6: 11KV feeder and 630KVA station at Delhi

Daily load profile showing Solar Power, Consumer Load and Differential load



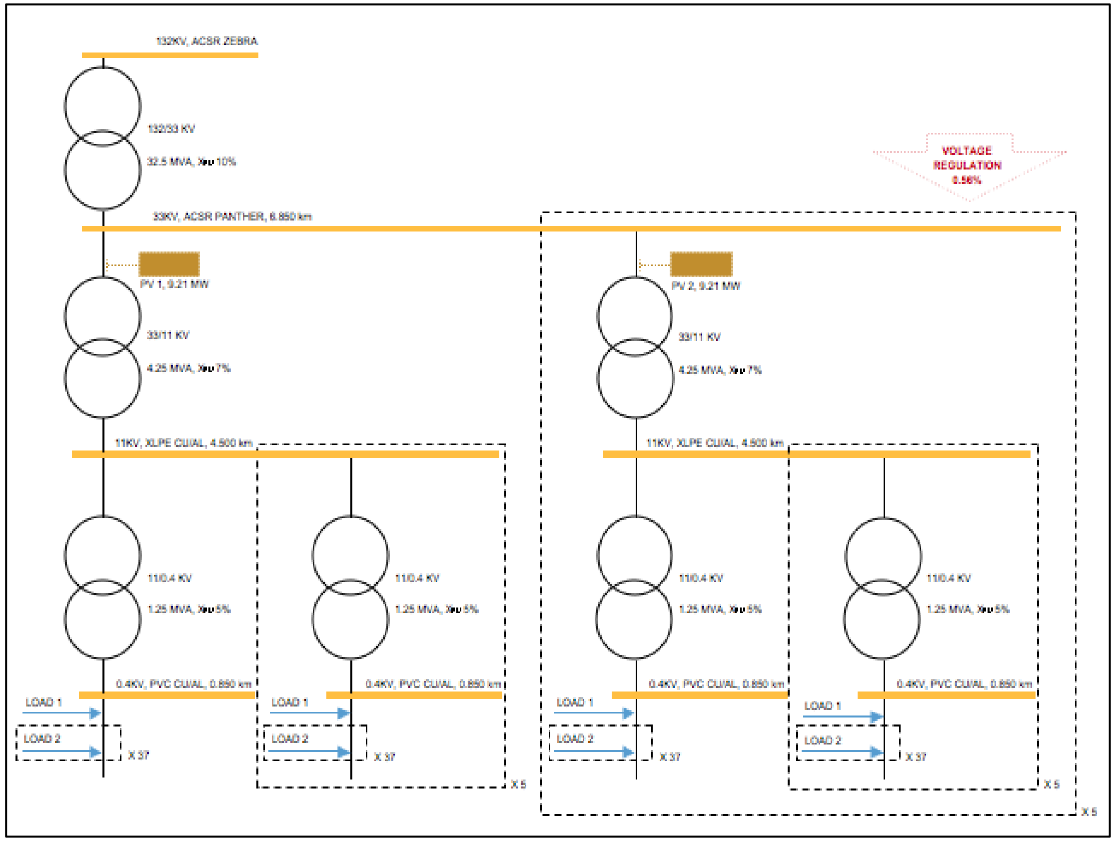
Case study 6: 11KV feeder and 630KVA station at Delhi

Annual load profile showing Solar Power, Consumer Load and Differential load



33KV Feeders – 32.5MVA, 40MVA and 50MVA station

Transformer Capacity	Conditions/ Assumptions
32.5MVA	▪ **Case 1:** Feeder Type ACSR PANTHER, length 6.85 km, 38 number of industrial loads of 17.50 KVA capacity ▪ **Case 2:** Feeder Type ACSR PANTHER, length 7.50 km, 32 number of industrial loads of 20.50 KVA capacity
40MVA	▪ **Case 1:** Feeder Type ACSR PANTHER, length 6.85 km, 32 number of industrial loads of 21.50 KVA capacity ▪ **Case 2:** Feeder Type ACSR PANTHER, length 6.85 km, 48 number of industrial loads of 21.50 KVA capacity
50MVA	▪ **Case 1:** Feeder Type ACSR PANTHER, length 8.65 km, 48 number of industrial loads of 30.50 KVA capacity ▪ **Case 2:** Feeder Type ACSR PANTHER, length 8.65 km, 48 number of industrial loads of 35.50 KVA capacity



SUPRABHA

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

INPUTS/ASSUMPTIONS							
HV Upstream Station Data	Units	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
Enter Station Installed Capacity:	KVA	32500	32500	40000	40000	50000	50000
Station Primary Voltage:	V	132000	132000	132000	132000	132000	132000
Station Secondary Voltage:	V	33000	33000	33000	33000	33000	33000
Station Running Capacity:		74%	73%	62%	62%	70%	72%
Enter Station Overloading:		0%	0%	0%	0%	0%	0%
Safety Factor (on station running capacity):		0%	0%	0%	0%	0%	0%
Margin Factor (on voltage regulation):		100%	100%	100%	100%	100%	100%
Enter PV Penetration:		170%	170%	160%	160%	170%	170%
PV Installed Capacity:	KW	55250	55250	64000	64000	85000	85000
LV Feeder Data							
Enter Operating Power Factor:		0.86	0.87	0.87	0.86	0.86	0.86
Enter Load Quantity:		38	32	32	48	48	48
Enter Running Load:	KVA	17.5	20.5	21.5	21.5	30.5	35.5
Enter Feeder Resistance R:	Ω/km	0.35	0.35	0.35	0.35	0.35	0.35
Enter Feeder Reactance XL:	Ω/km	0.015	0.015	0.015	0.015	0.015	0.015
Enter Feeder Length:	km	0.85	0.85	0.75	0.75	1.5	1.5

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

LV Upstream Station Data							
Enter Station Quantity		6	4	4	4	4	3
Enter Station Installed Capacity	KVA	1250	1500	1000	1500	2000	2500
Station Primary Voltage	V	11000	11000	11000	11000	11000	11000
Station Secondary Voltage	V	415	415	415	415	415	415
Station Running Capacity		53%	44%	69%	69%	73%	68%
Station Running Capacity	KVA	665	656	688	1032	1464	1704
Enter Station Per Unit Reactance XPU		5%	6%	5%	6%	6%	6%
Station Base Reactance XBASE	Ω	182	184	176	117	83	71
Station Actual Reactance	Ω	9.1	11.07	8.79	7.03	4.96	4.26
MV Feeder Data							
Operating Power Factor		0.83	0.84	0.84	0.83	0.83	0.83
Enter Feeder Resistance R:	Ω/km	0.28	0.28	0.28	0.28	0.28	0.28
Enter Feeder Reactance XL:	Ω/km	0.018	0.018	0.018	0.018	0.018	0.018
Enter Feeder Length:	km	4.5	4.75	4.85	5.5	6.25	6.25

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

MV Upstream Station Data							
Enter Station Quantity		6	9	9	6	6	7
Enter Station Installed Capacity	KVA	4250	4250	5000	5000	6500	6500
Station Primary Voltage	V	33000	33000	33000	33000	33000	33000
Station Secondary Voltage	V	11000	11000	11000	11000	11000	11000
Station Running Capacity		94%	62%	55%	83%	90%	79%
Station Running Capacity	KVA	3990	2624	2752	4128	5856	5112
Enter Station Per Unit Reactance XPU		7%	7%	7%	7%	8%	8%
Station Base Reactance XBASE	Ω	273	415	396	264	186	213
Station Actual Reactance XQ	Ω	19.11	29.05	27.7	18.47	14.88	17.04
HV Feeder Data							
Operating Power Factor		0.79	0.8	0.8	0.78	0.78	0.78
Enter Adjusted Power Factor		0.98	0.98	0.98	0.98	0.98	0.98
Enter Feeder Resistance R:	Ω/km	0.139	0.139	0.139	0.139	0.139	0.139
Enter Feeder Reactance XL:	Ω/km	0	0	0	0	0	0
Enter Feeder Length:	km	6.85	7.5	6.85	6.85	8.65	8.65
PV Inverter Data							
Enter Operating Power Factor:		1	1	1	1	1	1
Select Operating Mode:		Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)	Overexcited (lead)

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

OUTPUTS							
Peak PV Generation (KVA):	KVA	9208	6139	7111	10667	14167	12143
Peak PV Generation (KW):	KW	9208	6139	7111	10667	14167	12143
Peak PV Generation (KVAr):	KVAr	0	0	0	0	0	0
Running Load Consumption (W):	W	3910200	2571520	2696960	4045440	5738880	5009760
Running Load Consumption (VAr):	VAr	794000	522169	547641	821462	1165329	1017275
Reverse Power Flow:		Yes	Yes	Yes	Yes	Yes	Yes
Reverse Active Power Flow (Pkj):	W	5298133	3567369	4414151	6621227	8427787	7133097
Reverse Reactive Power Flow (Qkj):	VAr	0	0	0	0	0	0
Feeder End Voltage:	V	33183	33144	33160	33246	33405	33374
Feeder End Voltage Rise:		0.56%	0.44%	0.49%	0.75%	1.23%	1.13%
Acceptable:		Yes	Yes	Yes	Yes	Yes	Yes
Feeder Running Load:	A	559	565	697	695	882	873
Feeder Ampacity:	A	569	569	700	700	875	875
Loading on Grid Assets:		98%	99%	100%	99%	101%	100%
Acceptable:		Yes	Yes	Yes	Yes	No	Yes

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

Summary of simulation result for 33KV feeder with distributed PV Plants when permitted individual PV capacity is not more than sanctioned load/contract demand.

Minimum station/feeder loading when photovoltaic power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
100%	65.0	Upto 1.0	80.0	Upto 1.5	100.0	Upto 2.5
90%	61.8		76.0		95.0	
80%	58.5		72.0		90.0	
70%	55.3		68.0		85.0	
60%	52.0		64.0		80.0	
50%	48.8		60.0		75.0	
40%	45.5		56.0		70.0	
30%	42.3		52.0		65.0	
20%	39.0		48.0		60.0	
10%	35.8		44.0		55.0	
0%	32.5		40.0		50.0	

33KV Feeders – 32.5MVA, 40MVA and 50MVA station

Summary of simulation result for 33KV with distributed PV Plants when permitted individual PV capacity is not restricted by sanctioned load/contract demand.

Feeder length (m) when PV power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
19500	32.5	8.09	36.4	9.06	36.5	9.08
19000	32.5	7.88	37.4	9.07	37.25	9.03
18500	32.5	7.67	38.4	9.07	38.25	9.03
18000	32.5	7.47	39.4	9.05	39.5	9.08
17500	32.5	7.26	40.0	8.93	40.5	9.05
17000	32.5	7.05	40.0	8.68	41.75	9.06
16500	32.5	6.84	40.0	8.42	43.0	9.06
16000	32.5	6.64	40.0	8.17	44.25	9.04
15500	32.5	6.43	40.0	7.91	45.75	9.04
15000	32.5	6.22	40.0	7.66	47.25	9.04
14500	32.5	6.02	40.0	7.41	49.0	9.07

Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	11000	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	11.78%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	111.00%	
PV Installed Capacity:	12210	KW

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	30	
Enter Running Load:	10.80	KVA
Enter Feeder Resistance R:	0.450	Ω/km
Enter Feeder Reactance X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	4	
Enter Station Installed Capacity:	2750.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	324.00	KVA
Station Per Unit Reactance X_{PU}:	6.00%	
Station Base Reactance X_{BASE}:	373.46	Ω
Station Actual Reactance X_{Ω}:	22.41	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance R:	0.350	Ω/km
Enter Feeder Reactance X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	11000.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	1296.00	KVA
Station Per Unit Reactance X_{PU}:	7.00%	
Station Base Reactance X_{BASE}:	840.28	Ω
Station Actual Reactance X_{Ω}:	58.82	Ω

HV Feeder Data

Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.95	
Enter Feeder Resistance R:	0.139	Ω/km
Enter Feeder Reactance X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

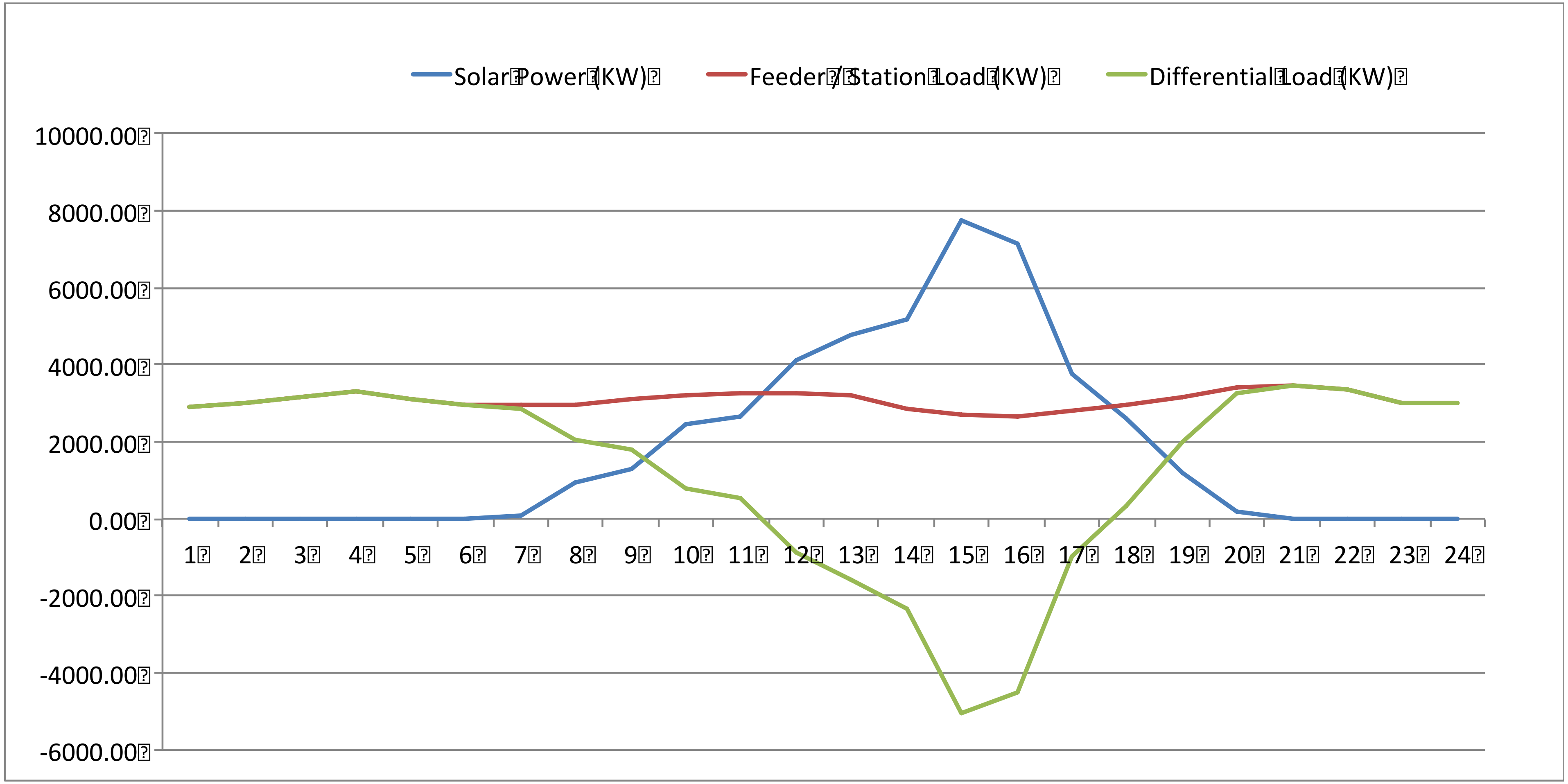
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	12210	KVA
Peak PV Generation (KW):	12210	KW
Peak PV Generation (KVAr):	0	KVAr
Running Load Consumption (W):	1231200	W
Running Load Consumption (VAr):	404676	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	10978800	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33458	V
Feeder End Voltage Rise:	1.39%	
Acceptable:	Yes	
Feeder Running Load:	189.58	A
Feeder Ampacity:	192.46	A
Loading of Grid Assets:	98.51%	
Acceptable:	Yes	

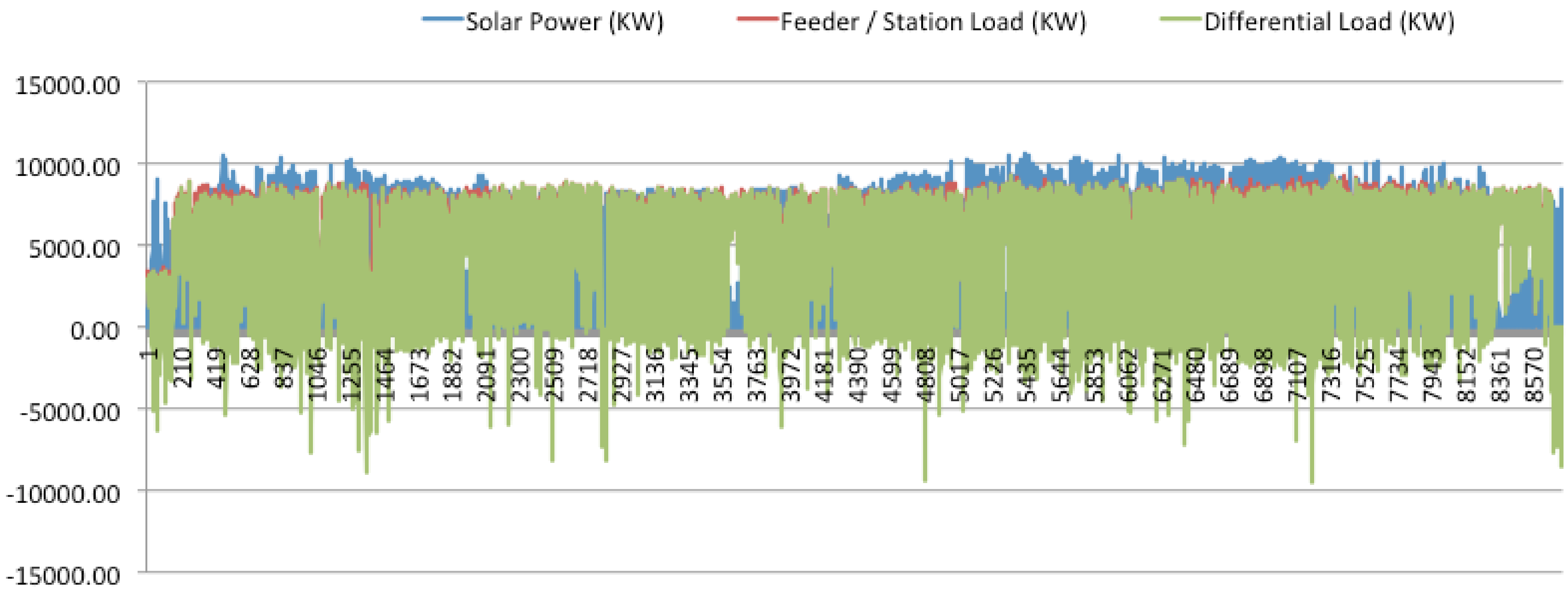
Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

Daily load profile showing Solar Power, Consumer Load and Differential load



Case study 7: 33KV feeder and 1.1MVA station at Jamshedpur

Annual load profile showing Solar Power, Consumer Load and Differential load



Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	1750	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	0.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	1750	KW

OUTPUTS

Peak PV Generation (KVA):	1750	KVA
Peak PV Generation (KW):	1750	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	6624	W
Running Load Consumption (VAr):	2822	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	1743376	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33070	V
Feeder End Voltage Rise:	0.21%	
Acceptable:	Yes	
Feeder Running Load:	30.44	A
Feeder Ampacity:	30.62	A
Loading of Grid Assets:	99.41%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	16	
Enter Running Load:	0.23	KVA
Enter Feeder Resistance - R:	0.450	Ω/km
Enter Feeder Reactance - X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	2	
Enter Station Installed Capacity:	875.00	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415	V
Station Running Capacity:	0.41%	
Station Running Capacity:	3.60	KVA
Station Per Unit Reactance - X_{PU}:	6.00%	
Station Base Reactance - X_{BASE}:	33611	Ω
Station Actual Reactance - X_{Ω}:	2017	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance - R:	0.350	Ω/km
Enter Feeder Reactance - X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	1750.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.41%	
Station Running Capacity:	7.20	KVA
Station Per Unit Reactance - X_{PU}:	7.00%	
Station Base Reactance - X_{BASE}:	151250	Ω
Station Actual Reactance - X_{Ω}:	10588	Ω

HV Feeder Data

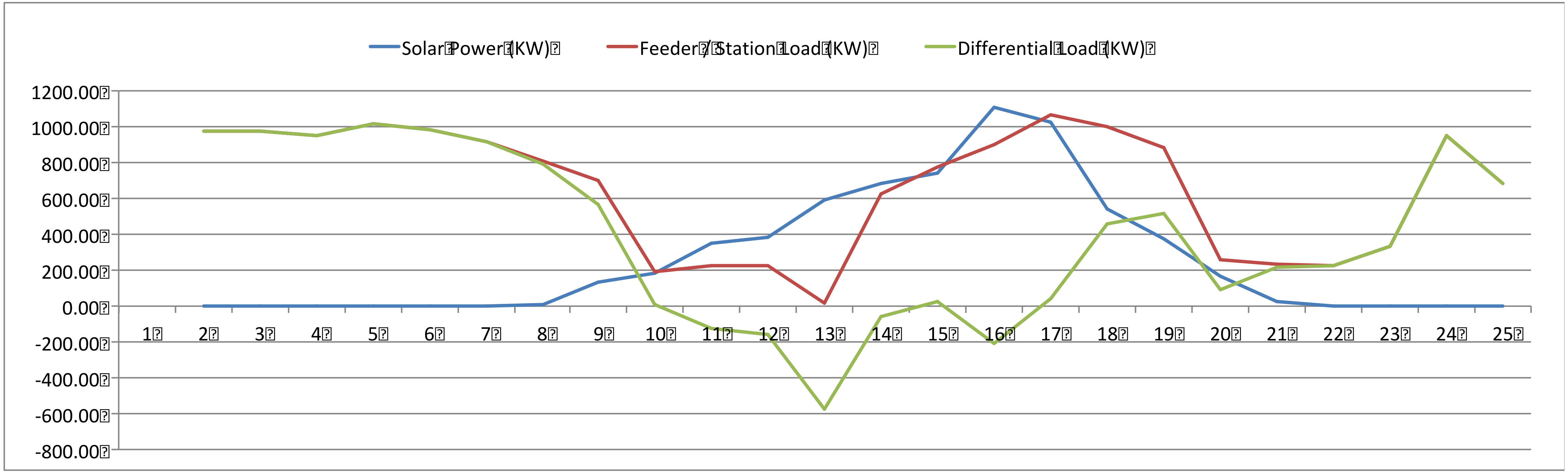
Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.92	
Enter Feeder Resistance - R:	0.139	Ω/km
Enter Feeder Reactance - X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

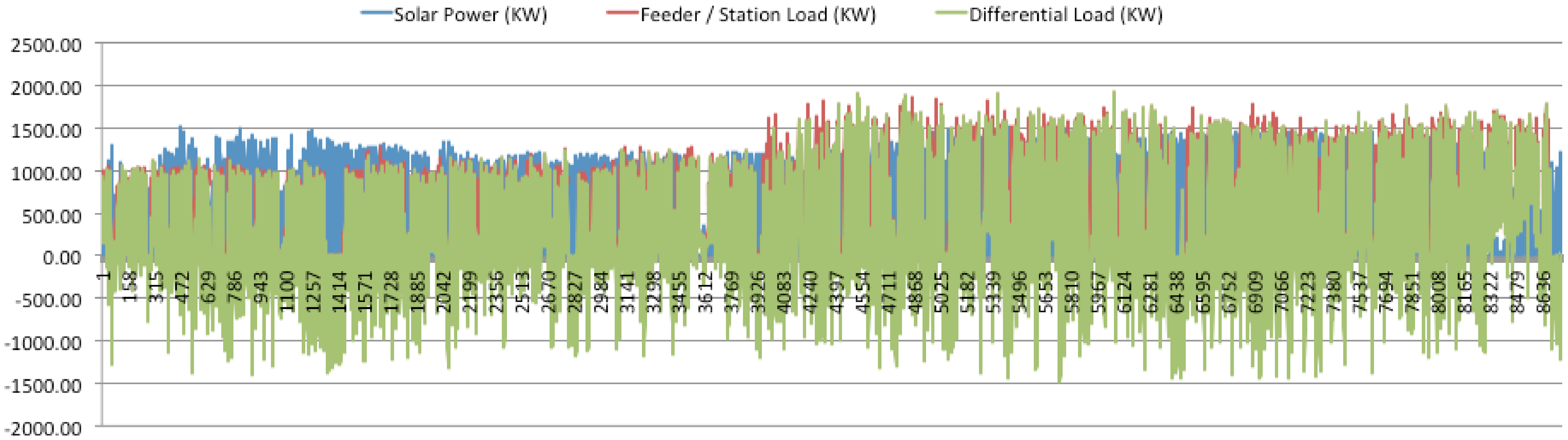
Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

Daily load profile showing Solar Power, Consumer Load and Differential load

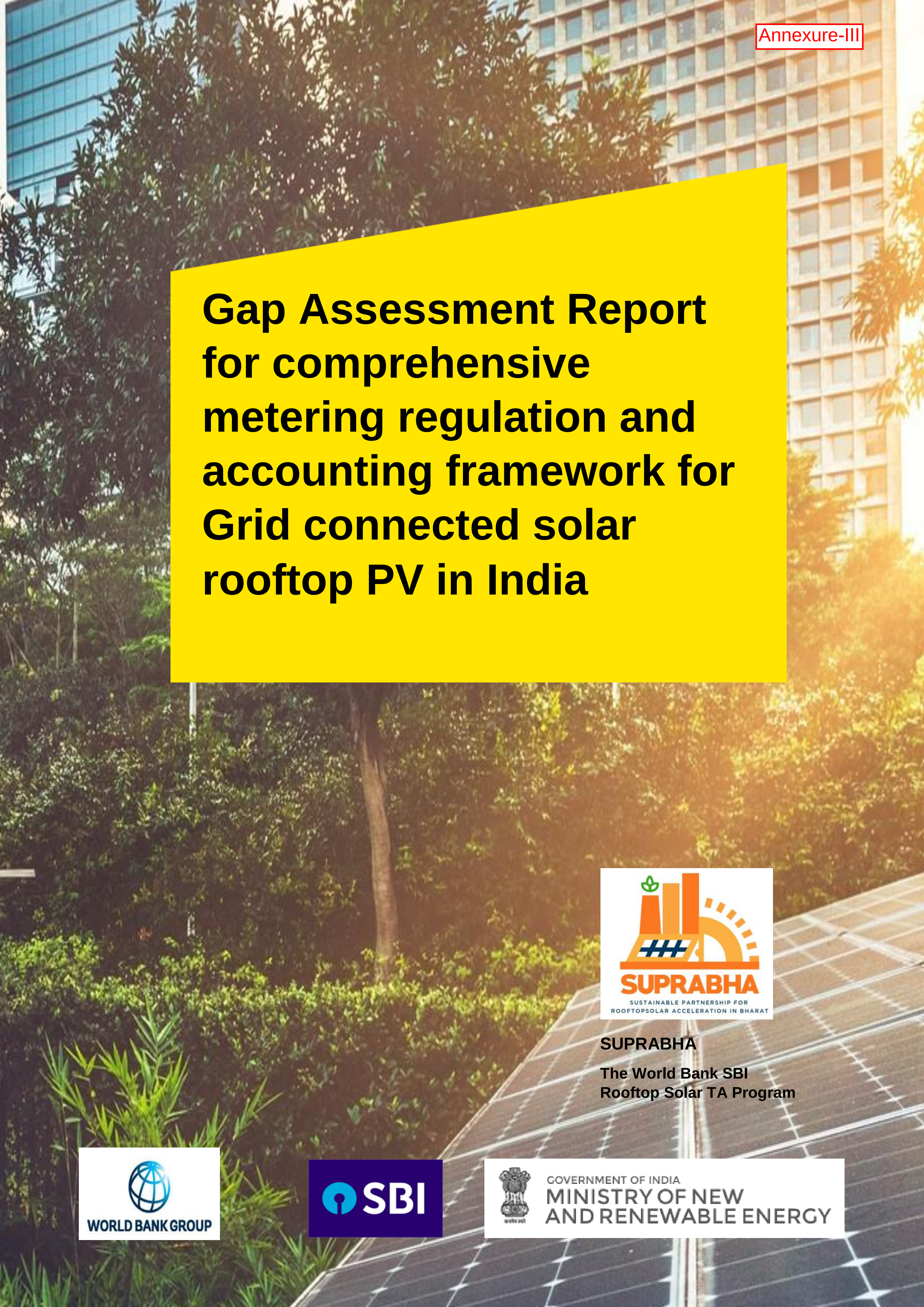


Case study 8: 33KV feeder and 1.75MVA station at Jamshedpur

Annual load profile showing Solar Power, Consumer Load and Differential load



Annexure-III



Gap Assessment Report for comprehensive metering regulation and accounting framework for Grid connected solar rooftop PV in India

SUPRABHA

SUSTAINABLE PARTNERSHIP FOR ROOFTOPSOLAR ACCELERATION IN BHARAT

SUPRABHA

The World Bank SBI Rooftop Solar TA Program

WORLD BANK GROUP

SBI

GOVERNMENT OF INDIA

MINISTRY OF NEW AND RENEWABLE ENERGY

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Acronyms

AB	Assembly Bill
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
APPC	Average power purchase cost
BDEW	German Association of Energy and Water Industries
BERC	Bihar Electricity Regulatory Commission
BESCOM	Bangalore Electricity Supply Company
BSES	Bombay Suburban Electric Supply
CAPEX	Capital Expenditure
CEA	Central Electricity authority
CESU	Central Electricity Supply Utility of Odisha
CFA	Central Finance Assistance
CPSU	California public utilities commission
CSERC	Chhattisgarh State Electricity Regulatory Commission
CSPDCL	Chhattisgarh State Power Distribution Company Limited
DERC	Delhi Electricity Regulatory Commission
DISCOM	Distribution Company
DL	Distribution Licensee
DPU	Department of Public Utilities
DT	Distribution Transformer
EDC	Electric Distribution Companies
EPC	Engineering, procurement and Construction
ERC	Electricity Regulatory Commission
EU	European Union
FIT	Feed In Tariff
FNN	network operation forum
FoR	Forum of Regulators
GERC	Gujarat Electricity Regulatory Commission
GOI	Government of India
GRPV	Grid Connected Rooftop Solar PV
HECO	Hawaiian Electric Companies
ICC	Illinois Commerce Commission
IPL	Interstate Power and Light
JNNSM	Jawaharlal Nehru National Solar Mission
KERC	Karnataka Electricity Regulatory Commission
LTEP	Long term Energy Plan
LVRT	low-voltage ride-through
MDMS	Meter Data Management System
MERC	Maharashtra Electricity Regulatory Commission
MNRE	Ministry of New and Renewable Energy
MRI	Meter Reading Instruments
NAPCC	National Action Plan on Climatic Change
NEG	Net Excess Generation
NEM	Net Energy Metering
NEM 2013	Net Metering Regulation, 2013
NSC	Net Surplus Consumption
O&M	Operations and maintenance
O&R	Orange and Rockland Utilities
OERC	Orissa Electricity Regulatory Commission
OPEX	Operating Expenditure
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PSC	Public Service Commission
PUC	Public Utilities Commission
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Certificate
RERC	Rajasthan Electricity Regulatory Commission
RESCO	Renewable Energy Service Company
RPO	Renewable Purchase Obligation
SBPDCL	South Bihar Power Distribution Company Limited
SCC	State Corporation Commission
SCE	Southern California Edison

SDG&E	San Diego Gas & Electric
SERC	State Electricity Regulatory Commission
SNA	State Nodal Agency
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
TOU	Time of Use
TPO	Third Party Owned
UERC	Uttarakhand Electricity Regulatory Commission
UPCL	Uttarakhand Power Corporation Limited
UT	Union Territory
VAT	Value Added Tax
VDE	Verband der Elektrotechnik
WBERC	West Bengal Electricity Regulatory Commission

1 Executive Summary

This gap assessment report has been developed as part of the ‘Developing comprehensive metering Regulations and accounting framework of Grid-connected Rooftop Photovoltaic (GRPV) deployment in India’ activity under the World Bank-State Bank of India Grid-connected Rooftop Photovoltaic Technical Assistance program.

Background of the study

The global success stories of rooftop solar PV on the distributed grid management and power markets, has enabled to gain attention and attract substantial interest from entrepreneurs, developers, financial institutions, development banks, end-users, as well as government entities in India since 2010. The gained momentum aided in development of regulatory framework for Grid connected rooftop solar in India. Forum of Regulation (FOR), in 2013, formulated a draft model Net Metering Regulation, 2013 (NEM 2013), a concept adopted in countries worldwide.

In 2014, the Government of India (GoI) has set an ambitious target to achieve 40 GW of cumulative installed capacity from rooftop solar power by 2022. In order to achieve this target, a strategic combination of Top- Down impetus and Bottom-Up execution approach was initiated, in which GoI, in partnership with the state governments and regulators, adopted a number of measures to promote the rooftop solar sector at the state. In the process, nearly 29 states adopted the model net metering regulations formulated in 2013 with few or no changes to the draft regulation.

During the conceptualization phase of model regulation, Capital Expenditure (CAPEX) or self-owned model was the most dominant business model in the rooftop solar sector. The new changes in the market scenario poses limitations on the present regulations and several implementation challenges, thus a modest uptake of rooftop solar is witnessed in the country. For instance, the present regulatory framework is focused on self-consumption and therefore the provisions of model regulation, 2013 and that of state regulations has put certain restrictions in terms of system capacity that an individual can install, how much capacity can be allowed on single Distribution Transformer (DT) and maximum capacity that can installed by individual consumer.

The present provisions of model regulation, 2013 and that of state regulations has put certain restrictions in terms of system capacity that an individual can install, how much capacity can be allowed on single DT and maximum capacity that can installed by individual consumer so that to promote self-consumption through net metering. Therefore, the cumulative rooftop installations capacity as of 31st September, 2017 is only 1861 MW vis-à-vis a cumulative installed solar capacity of 14,163 MW.

In order to support the GoI targets on widespread installation of rooftop solar PV, the World Bank is lending $625 million (under Perform for Results (P4R) lending instrument) to the State Bank of India (SBI) to debt finance GRPV projects and capacitate various stakeholder involved. As part of the loan, SBI has proposed a Technical Assistance (TA) program through a Project Management Consultant (PMC) under a Ministry of New & Renewable Energy (MNRE)-led Steering Committee to support strengthening market ecosystem with focus on areas of policy, regulation, process alignments and demand creation.

Under the TA program, a study has been commissioned to support Forum of Regulator to update Model Net metering regulation developed in 2013 and to develop a ‘Comprehensive metering and Accounting framework for Rooftop Solar PV in India’. The study aims to identify gaps in the regulatory framework based on upcoming business models and international review, available infrastructure for deployment, and impact on various stakeholders; and propose necessary changes in the existing model regulation.

Development of regulatory framework for GRPV in India

As mentioned earlier, the development of regulatory framework for solar Grid connected rooftop solar started when Forum of Regulation (FOR), in 2013, first came up with a draft model regulation for GRPV system based on net metering. Various states introduced their net metering regulations post modifications/additions to the existing rooftop solar model regulations.

Apprehensive about introducing distributed generation in distribution system (below 33 KV) which was designed to unidirectional power flow, the cumulative capacity of GRPV systems on a particular DT were restricted at 15% of peak capacity of that particular DT mainly to avoid any reverse power flow. The salient features of NEM 2013 are provided in the table below:

Table 1: Salient features of Net metering Regulation, 2013

Sr. No.	Provisions	Descriptions
1	Applicability	All consumers
2	Business models	CAPEX and RESCO
3	Metering principles	Net metering
4	System capacity	Maximum capacity of 1 MW
5	Limits on DT loading	15% (to be reviewed based on technical studies or standards subsequently defined by Central Electricity Authority (CEA)
6	Exemption from other charges	wheeling charges, cross-subsidy surcharge and Banking charges
7	Communication capability	Meter Reading Instrument (MRI) compatible
8	Rate applicable in case of export to the grid	No payment if electricity generated exceeds 90% of the electricity consumed
9	Settlement period	One year
10	Renewable Purchase Obligation (RPO) compliance	Units consumed by the consumer will qualify for the RPO compliance for the Distribution Licensee
11	Managing safety	Primarily responsibility of consumer, auto shutting of solar plant when grid supplier fails are also provided

In its Report of August, 2013, the Working Group of the FoR had also said the limit of 15% on DT can be reviewed based on technical studies conducted by the utility or based on standards subsequently defined by CEA.

Model regulation has also put maximum limit of 1 MW, the states have also put restrictions on consumers' individual capacity as some percentage of their sanctioned load or connected load. The range for individual GRPV system capacity is between 40% and 100% of the sanctioned load.

The limits for GRPV systems that can be installed on a particular DT vary from state to state. Some states have adopted 15% limit in line with the Net Metering Regulation, 2013 (NEM, 2013), whereas few states have relaxed it further. The range for DT loading is between 15% and 75% (in Odisha). In state of Telangana, the DT loading is allowed till 50% with additional condition that if system study allows, more GRPV systems can be allowed on the same DT.

Brief summary of major provisions from state regulations related to GRPV system are provided in the table below:

Table 2: Major Provisions in state regulations related to GRPV system

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumers
2.	Business models	CAPEX and RESCO
3.	Metering principles	Mostly net metering; gross metering in few states
4.	System capacity	40% to 100% of the sanctioned load
5.	Limits on DT loading	15% to 75% of the peak capacity or rated capacity of DT
6.	Exemption from other charges	wheeling charges, cross-subsidy surcharge and additional surcharge; Banking charges and transmission charges; in some states Transmission loss and wheeling loss is also exempted
7.	Communication capability	MRI compatible; few states have asked for Advanced Metering Infrastructure (AMI) compatible net meters
8.	Rate applicable in case of export to the grid	Feed in Tariff (FiT), Power Purchase Agreement (PPA) rate or Average Power Purchase Cost (APPC) (in most cases)
9.	Settlement period	Mostly one year; few states like Andhra Pradesh and Telangana have half-yearly settlement period. In most cases, the settlement year is financial year (April to March) except, Punjab and Sikkim where the settlement year starts from October.
10.	RPO compliance	Major states allow solar energy generated as part of RPO compliance; In case of Karnataka if the GRPV is DISCOM owned then total generation is considered under RPO compliance otherwise total energy purchased is considered
11.	Managing safety	Primarily responsibility of consumer, provisions for auto-shutting of solar plant when grid supplier fails is also provided

Global experience

In the developed countries, the GRPV segment has seen tremendous growth. In USA, as on November 2017, out of the total 53 GW[1] of solar PV capacity installed, around 20 GW (38%) of came from solar roof-top. In China, at the end of 2017, distributed solar PV capacity reached to 19.44 GW[2] (including roof-top as well as ground mounted solar PV systems) which is around 15% of the total 130 GW of solar PV capacity installed. In residential roof-top segment, 2 GW and 10 GW of roof-top solar systems has been installed in China and USA, respectively, compared to 377 MW (as on September 2017) in India.

The key learnings from the international experience suggests that the GRPV segment in India can also grow by removing present restriction in terms of system capacity or DT capacity, to the extent possible by allowing higher system capacities with adequate measures from system operations points of view, increase consumer reach by adopting different business models for different types of consumers, and providing suitable energy accounting and remunerative commercial settlement principles to attract consumers.

The major provisions from international experience are provided in the table below:

1 https://www.seia.org/solar-industry-research-data
2 https://mercomindia.com/china-2017-solar-report/

Table 3: Major Provisions related to GRPV in other countries

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumer with multiple options to choose: business models and financing
2.	Business models	CAPEX and RESCO, Community and virtual
3.	Metering principles	Net/Gross/ Virtual (choice to consumer to select net or gross metering)
4.	System capacity	1. USA: California – 100% of the sanctioned load for Net Energy Metering (NEM), Colorado – 120% of the customer's average demand and Virginia – not exceeding customers annual load 2. Brazil – 100% of the sanctioned load or contract demand for NEM 3. Maximum System Capacity – California – 5 MW to 10 MW, Mississippi – 2 MW for non-residential consumer and 20 KW for residential, North Carolina – 1 MW
5.	Limits on system loading	Overall limit based on peak demand of utility like, 1.5% to 5% in USA
6.	Communication capability	1. Germany: DISCOMs are moving towards smart meters; though not compulsory 2. California: DISCOMs are moving towards smart meters; though not compulsory
7.	Rate applicable in case of export to the grid	1. Germany: Feed in Tariff 2. USA: California – 12 month average spot market price; Virginia, Nevada and Minnesota -- Avoided cost rate
8.	Settlement period	1. USA: In the states of Virginia, Minnesota, California, the settlement period is one year with option to roll over credit to next settlement period or settle at the end of 12 months

As of May 2015, 48 countries worldwide had implemented net metering schemes, in most of the cases on a national level. Net metering became the incentive policy choice in 26 countries since 2012, when around 22 countries had adopted net metering schemes.[3] EY has assessed the regulatory scenario of the following global markets. Few key takeaways from the international experience are provided below:

California State (USA):

- Higher system capacity (more than 1 MW) can be allowed depending upon the consumer category, their demand and technical feasibility of interconnection.
- As the purpose of net metering regulation is to promote self –consumption it can be achieved where consumer demand is high and generation from higher GRPV capacity can be absorbed by the consumer itself at single location.
- The issue of cost of upgrading infrastructure will also arise when higher capacity is allowed which needs to be either recovered from consumer or shared by DISCOM and consumer depending upon the up gradation required.
- Excess generation, if any, after settlement period should be compensated at reasonable rate. In many cases, no payment is done for the excess generation.
- Different business models as per consumer needs can be allowed.

Germany:

[3] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

- Visibility and control over solar generation beyond certain capacity is must for the DISCOM or system operator in view of requirement of stable grid operation. For low capacity systems certain restrictions should be put so that minimum level of feed-in is maintained.
- The GRPV invertor system must be able to respond to the system requirement and follow instruction of the area system operator and their technical specifications needs to be designed accordingly.
- Going forward, stringent interconnection standards will be required when more and more GRPV systems will get added in the distribution network.

European Union:

- Innovation in financing mechanisms and business models are only possible when the basic regulatory framework allows new entrants and ways of installing GRPV systems. If the regulatory framework is overly restrictive, new business models that can facilitate the up-front investment required cannot be accepted. It is critical that electricity markets rules are opened up across to allow for more decentralised electricity generation and supply.

Gap Assessment

Based on international experience and cases studies observed in India in recent times, the identified gaps which need review while framing proposed model regulation are listed below:

1. Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity
2. Different limits on GRPV capacities connected to DT requires review
3. Limited business models options available to consumer and developers, limited scope to DISCOMs in present scenario
4. Definition of premises and Solar roof-top PV systems needs review owning to future possibility of different scenarios
5. Limited provisions on real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems
6. Present PPA or connection agreement need additional aspects related to change in ownership and flexibility in existing PPA/connection agreement
7. No remuneration for excess generation in present energy accounting and commercial settlement principles
8. Metering and communication requirements needs review to provide greater visibility on solar generation to DISCOMs and system operations

Introduction

2 Introduction

2.1 Development of roof-top solar in India

Government of India (GoI) has launched National Action Plan on Climatic Change (NAPCC) in 2008 to outline a structure for the ecologically sustainable development of the country. Jawaharlal Nehru National Solar Mission (JNNSM), one of the several missions launched under this action plan, aimed at achieving 20 GW of grid connected solar Grid connected rooftop solar by 2022[4]. This target was further revised to five folds, to an ambitious target of 100 GW to be achieved by 2022[5]. This 100 GW plan includes 40 GW capacity addition from grid connected solar rooftop PV (GRPV) systems and remaining 60 GW is expected from large utility scale ground mounted solar projects in the country.

The vigour in India's solar PV market resulted in tremendous growth from installed capacity from 37 MW in FY 2010-11 to 21651 MW[6] by FY 2017-18. The year wise capacity addition is provided in the graph below:

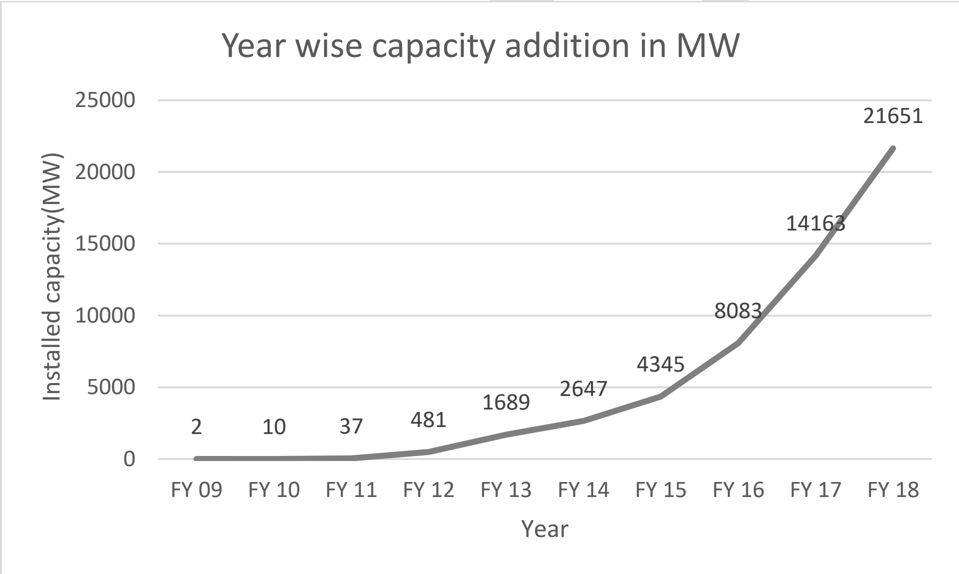

Figure 1 : Evolution of solar energy[7]

The above figure clearly shows that the cumulative installed capacity has snowballed since JNNSM phase 1 i.e. 2008-09.

As mentioned earlier, the GoI has set an ambitious target of achieving 100 GW of installation capacity of solar energy by 2022 which includes 40 GW from GRPV system. In India, only 1861 MW of GRPV systems were installed by the end of September 2017. Overall share of GRPV system in total installed solar capacity has remained around 10% which is very less compared to developed countries like Germany, USA and China. Germany is the world leader in deployment of solar roof-top systems where out of the total 40 GW of solar PV capacity installed in 2015, around 74%[8] capacity was contributed by solar roof-top.

In USA, as on November 2017, out of the total 53 GW[9] of solar PV capacity installed, around 20 GW (38%) of came from solar roof-top. In China, at the end of 2017, distributed solar PV capacity reached

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[4] http://www.seci.gov.in/content/innerinitiative/jnnsm.php

[5] http://niti.gov.in/writereaddata/files/writereaddata/files/document_publication/report-175-GW-RE.pdf

[6] http://www.cea.nic.in/reports/monthly/installedcapacity/2018/installed_capacity-03.pdf

[7] http://shaktifoundation.in/wp-content/uploads/2014/02/Rooftop-Solar-Garnering-Support-from-Distribution-Utilities.pdf

[8] https://mnre.gov.in/file-manager/UserFiles/workshop-gcrt-0870616/german.pdf

[9] https://www.seia.org/solar-industry-research-data

to 19.44 GW[10] (including roof-top as well as ground mounted solar PV systems) which is around 15% of the total 130 GW of solar PV capacity installed. In residential roof-top segment, 2 GW and 10 GW of roof-top solar systems has been installed in China and 1 USA, respectively, compared to 377 MW (as on September 2017) in India.

Therefore, to achieve the ambitious target of 40 MW, policy and regulatory interventions are essential to develop market. The graph below indicates the yearly capacity addition targets government has set which are to be achieved by 2022:

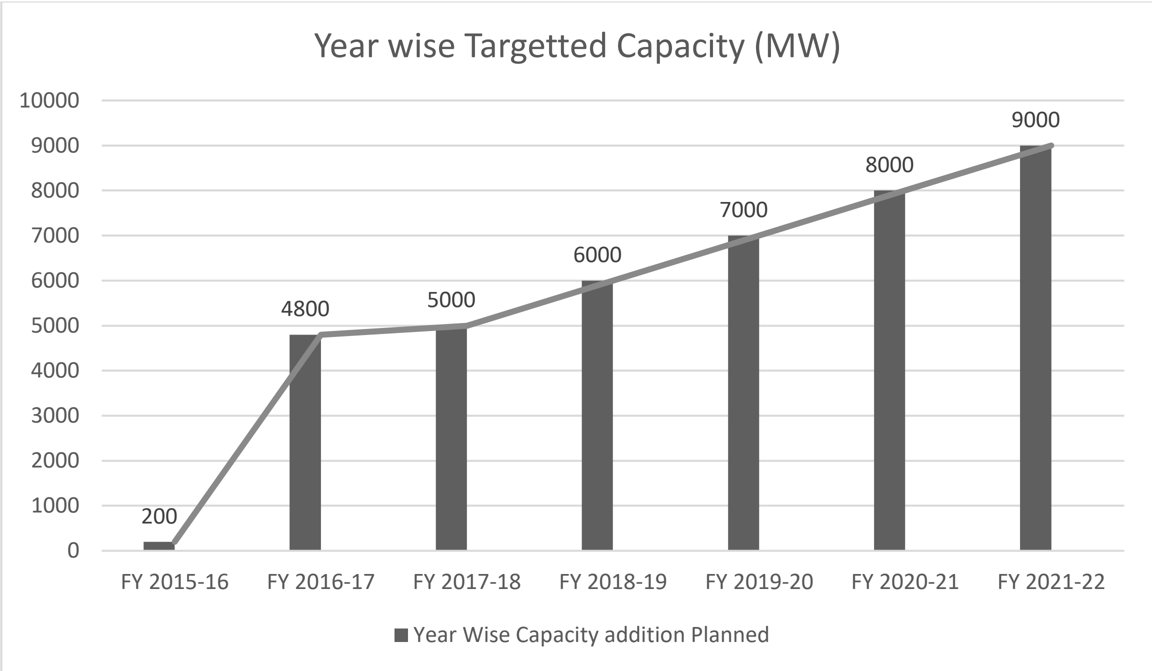

Figure 2 : Year wise capacity addition targets[11]

The uphill target of 4.8 GW in FY 2016-17 from 200 MW in FY 2015-16 set a clear trend of the next five years till 2022. Effective execution thus requires a sustainable GRPV eco-system where all stakeholders co-exist with a clear win-win situation. Therefore, policy landscape plays a pivotal role in creating the same. Although the GRPV segment has seen a slow growth rate in the past, with decreasing cost of solar PV modules and government impetus, this sector will see promising future in years to come.

Benefits of GRPV systems are manifold. It helps consumer in reducing the electricity bills. This will help consumers in cost savings particularly in industrial and commercial segment which pays significantly higher tariffs. Another advantage of GRPV systems is reduction of transmission and distribution losses. As the GRPV systems are directly connected to the distribution grid, the system losses can be reduced. The GRPV systems would also help in reducing the dependency on thermal, gas, etc. to some extent and can also help in differing the capital expenditure for augmenting transmission and distribution network. The gestation time required for setting the solar Grid connected rooftop solar is less which helps the prosumers to generate electricity as soon as the setup is complete.

This system also helps in Improving tail-end grid voltages and reduction in system congestion with higher self-consumption of solar electricity.

[10] https://mercomindia.com/china-2017-solar-report/

[11] https://mnre.gov.in/file-manager/UserFiles/OM-year-wise-cumulative-target-for-100000MW-grid-connected-SP-project.pdf

Moreover, Renewable sources of energy boost clean energy and helps in lowering the pollution and GHH emissions. Therefore, in order to achieve energy conservation and ecological stability, proliferation of GRPV systems will play an instrumental role.

2.2 Policy initiatives at central and state level

The Central government has launched capital subsidy funding to boost the solar Grid connected rooftop solar market in India. At central level the government provides financial incentives for states to encourage grid connected solar rooftop. The government also provides concessional loans for the investors of grid connected solar rooftop. An online portal "SPIN" has been launched which calculates total Grid connected rooftop solar area, the solar panel capacity one can install and the budget constraints associated with the same. Technical cooperation is also provided so that any layman can come forward and invest in grid connected solar rooftop. RPO regulations has also been extended further to accommodate upcoming renewable capacity, especially, the solar capacity.

Under the central financial assistance scheme (CFA), Ministry of New & Renewable Energy (MNRE) provides subsidy to the end users and the subsidy needs to be availed via state nodal agencies (SNAs).

Central Government, on 30th December 2015, approved an increase in the CFA from Rs. 600 crore to Rs. 5,000 crore for implementation of 'Grid Connected Grid connected rooftop solar and Small Solar Power Plants Programme' up to the financial year 2019- 20. The CFA being provided is up to 30% of benchmark cost/tender cost (whichever is lower) for general category states/UTs and up to 70% of benchmark cost/tender cost (Whichever is lower) for special category states/UTs, i.e. North Eastern States including Sikkim, Uttarakhand, Himachal Pradesh, Jammu & Kashmir, Lakshadweep, Andaman & Nicobar Islands. Only residential, institutional and social sectors are eligible for CFA under the programme and no CFA for commercial & industrial establishments. For Government Sector an achievement linked incentive scheme was made available under the programme as provided in the table below:

Table 4: Achievement linked incentive scheme for government sector

Sr. No.	Achievement vs target	General category states (INR/KW)	Special category states (INR/KW)
1.	**Greater than 80%**	16250	39000
2.	**Greater than 50% but less than 80%**	9750	23400
3.	**Greater than 40% but less than 50%**	6500	15600
4.	**Less than 40%**	0	0

At central level, model net metering regulations were framed in 2013 by Forum of Regulator (FoR), which was a benchmark for state level net metering regulations. The net metering regulations for specific states have also been notified by the regulators and the same has been followed by the distribution licensee and consumers. Almost in 15[12] states solar policy have been framed by the state regulatory commissions. The RPO targets are being set up by the state regulators for compulsory power purchase from renewable sources; solar and non-solar and are to be met by each utilities of the state. Further as per National Tariff Policy, 8% RPO obligations has been now mandated.

[12] https://mnre.gov.in/file-manager/UserFiles/state-solar-power-policies.html

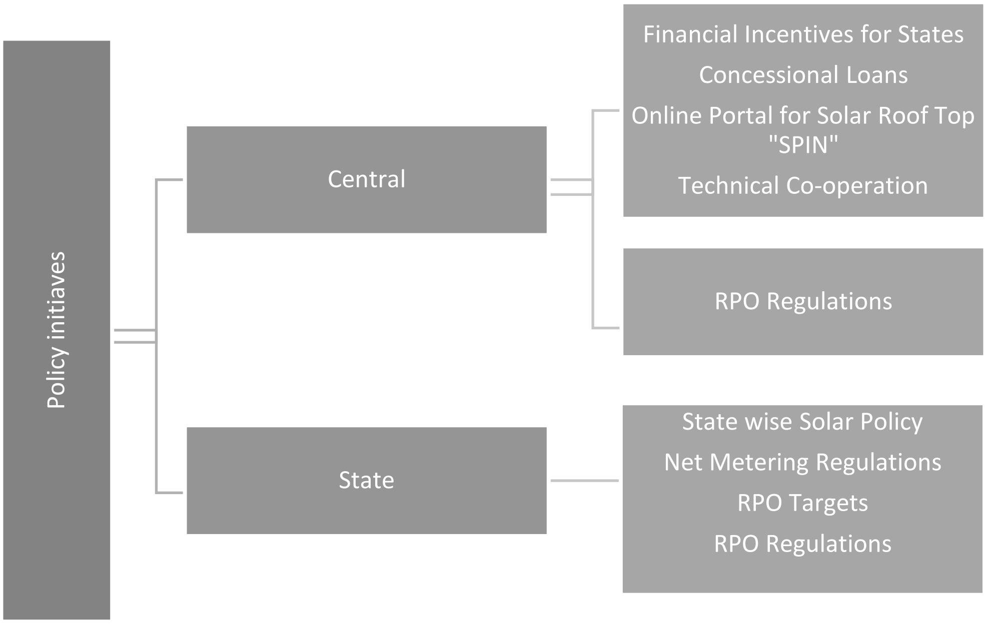

Figure 3 : Policy initiatives at central and state level

At policy level, in last 3-4 years, in addition to present incentives provided by central government, many states have also came up with incentive polices such as capital subsidy, tax exemption and tax holidays particularly aiming at increasing GRPV penetration.

2.3 Decreasing trends in cost of solar system

Following the global solar market trends, Indian market has also seen sharp decline in PV module prices, resulting in overall reduction in cost of solar projects. The module prices have fallen by 29% from 2015 to 2017 mainly due low cost imports from Chinese/Korean markets, technological improvements in global arena and huge scalability of module manufacturing in China.

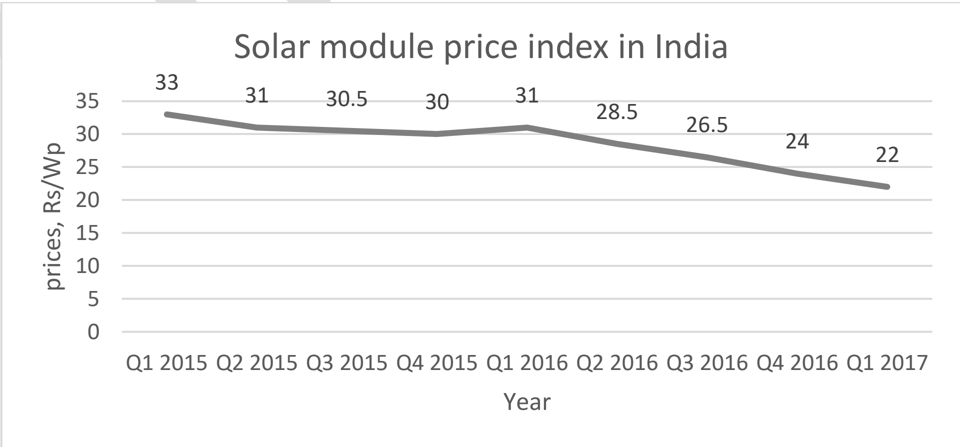

Figure 4 : Solar module prices in India[13]

[13] http://www.bridgetoindia.com/wp-content/uploads/2017/05/BRIDGE-TO-INDIA_India-Solar-Handbook_2017-1.pdf

The prices of solar module have fallen by 8 % over the last quarter. It depicts that the reduction in solar module trend might continue and the market is yet to reach at a price equilibrium stage. Based on the recent trends in module price fall, a system size pricing trend has been shown in the graph below:

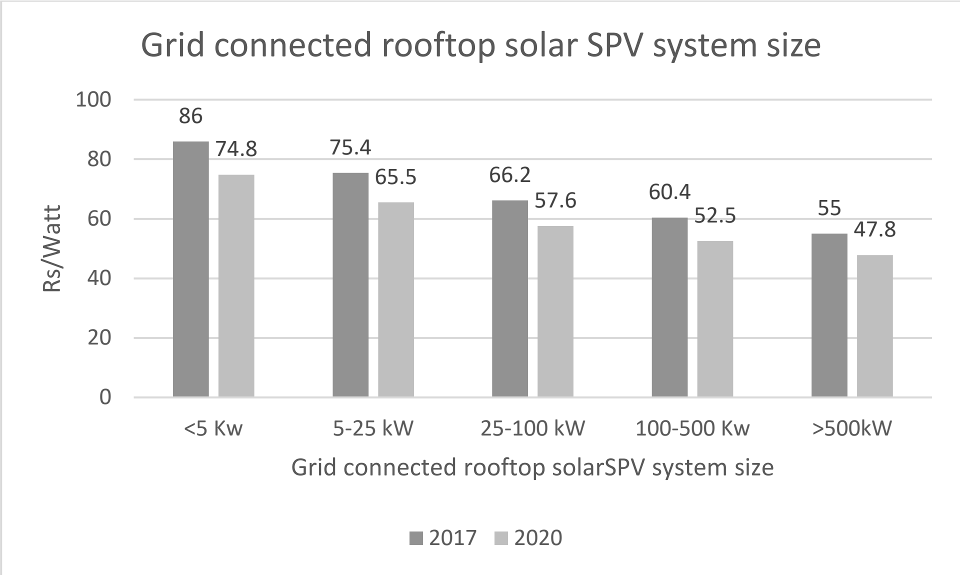

Figure 5 : System size pricing trend[14]

Due to economies of scale, larger sized systems result in less per Watt cost and it is anticipated that in 2020, the benchmark might reach below even 50 INR per Watt for project sizes with more than 600 kW capacity.

2.4 Availability of compatible metering technology

Solar Grid connected rooftop solar plants mainly are deployed in consumer premises and need either Net Meters or Gross Metering arrangements. In both metering arrangement, separate meters will be installed for recording the energy exported to the grid. For a simple net metering arrangement, the present practice mandates installation of both solar meter and net meter.

The export and import meters with communication technologies will work as smart meters. The Meter data can be managed at the developer side with Meter Data Management System (MDMS). The Metering Infrastructure like AMI and AMR are utilised for optimisation of benefits to developers as well as utilities and reduces manual interference.

2.5 Evolution of present regulatory framework for grid connected solar rooftop

The development of regulatory framework for solar Grid connected rooftop solar started when Forum of Regulation (FOR), in 2013, first came up with a draft model regulation for GRPV system based on net metering. Thereafter, many state regulatory commissions notified net metering regulations for their respective states after making suitable changes based on experiences gained in the solar roof top segment and available metering & communication technology. At present, 23 states and 4 union territories have issued net metering regulations for GRPV.

2.5.1 Model regulations 2013

One of the key policy level interventions was drafting model regulations for net metering in 2013 so that the states can refer the model regulation while developing regulatory framework for solar roof top for their own states.

[14] http://www.bridgetoindia.com/wp-content/uploads/2017/05/BRIDGE-TO-INDIA_India-Solar-Handbook_2017-1.pdf

Till then, major development was seen in utility scale ground mounted solar plants, much interest was not seen in solar roof-top segment. At policy and regulatory level there was no clarity on technical standards, interconnection arrangements, principles of accounting and commercial settlement under net metering and applicability of charges like wheeling charges, cross-subsidy surcharge and additional surcharge; Banking charges and transmission charges etc.

The NEM 2013 primarily focuses on self-consumption. To do so, the energy accounting and commercial settlement principles does not provide any payment for generation exceeding 90% of their total consumption in a particular settlement period. The excess generation is not carry forwarded to the next settlement period.

Apprehensive about introducing distributed generation in distribution system (below 33 KV) which was designed to unidirectional power flow, the cumulative capacity of GRPV systems on a particular DT were restricted at 15% of peak capacity of that particular DT mainly to avoid any reverse power flow: The salient features of NEM 2013 are provided in the table below:

Table 5: Salient features of Net metering Regulation, 2013

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumers
2.	Business models	CAPEX and RESCO
3.	Metering principles	Net metering
4.	System capacity	Maximum capacity of 1 MW
5.	Limits on DT loading	15% (to be reviewed based on technical studies or standards subsequently defined by CEA)
6.	Exemption from other charges	wheeling charges, cross-subsidy surcharge and Banking charges
7.	Communication capability	MRI compatible
8.	Rate applicable in case of export to the grid	No payment if electricity generated exceeds 90% of the electricity consumed
9.	Settlement period	One year
10.	RPO compliance	Units consumed by the consumer will qualify for the RPO compliance for the Distribution Licensee
11.	Managing safety	Primarily responsibility of consumer, auto shutting of solar plant when grid supplier fails are also provided

In its Report of August, 2013, the Working Group of the FoR had also said the limit of 15% on DT can be reviewed based on technical studies conducted by the utility or based on standards subsequently defined by CEA. In the same report, FoR had set out the following reasoning for suggesting a capacity limit of 1 MW for Roof-top Solar PV Net Metering arrangements in its draft Model Regulations:

> "The following provisions can be considered for developing the regulatory framework for net-metering based roof-top PV systems:
>
> The maximum rated capacity for a roof-top project for interconnection with the grid at a specific grid voltage level shall be as per the provisions of the respective state supply/distribution code, read for the purpose of deciding the interconnection voltage by replacing the contracted demand with maximum rated capacity of the Solar roof-top system.
>
> The maximum capacity of roof-top Solar system defined for grid connection in several states is 1 MW. The maximum permissible capacity under Rooftop and Other Small Solar Power Generation Plant (RPSSGP) is 2 MW, where most projects have been ground-mounted small-scale projects. Considering the above, the maximum capacity limit for roof-top Solar system can be capped at 1 MW for a single metering point to qualify under net-metering."

In line with NEM 2013, many states have then restricted maximum size of GRPV system at 1 MW as discussed subsequently.

2.5.2 State regulations

Following the model NEM 2013, different states started issuing their own state regulations. Structurally, the state regulations revolved around the NEM 2013, like:

1. Metering schemes
2. System size, limit on DT capacity and maximum size allowed
3. Interconnection arrangement
4. Energy accounting and commercial settlement, and
5. Regulatory provisions related to RPO, Renewable Energy Certificates (REC) and open access

The states has also adopted principles based on the experience gained, metering and communication technology available at the time of making regulation. Most of the states have adopted net metering scheme and in some cases like Andhra Pradesh and Telangana, both; gross metering and net metering. The net metering regulation has put maximum system size of 1 MW which has been the same in all state regulations.

The voltage wise capacity that can be connected is also provided in state regulations, though vary across states. Model regulation has put maximum limit of 1 MW, the states have also put restrictions on consumers' individual capacity as some percentage of their sanctioned load or connected load. The range for individual GRPV system capacity is between 40% and 100% of the sanctioned load.

The DT loading limits are also different in different states. Some states have adopted 15% limit in line with the NEM 2013 whereas few states have relaxed it further. The range for DT loading is between 15% and 75% (in Odisha). In state of Telangana, the DT loading is allowed till 50% with additional condition that if system study allowed, more GRPV systems can be allowed on the same DT.

Brief summary of major provisions from state regulations related to GRPV system are provided in the table below:

Table 6: Major Provisions in state regulations related to GRPV system

Sr. No.	Provisions	Descriptions
2.	Applicability	All consumers
3.	Business models	CAPEX and RESCO
4.	Metering principles	Mostly net metering; gross metering in few states
5.	System capacity	40% to 100% of the sanctioned load
6.	Limits on DT loading	15% to 75% of the peak capacity or rated capacity of DT
7.	Exemption from other charges	wheeling charges, cross-subsidy surcharge and additional surcharge; Banking charges and transmission charges; in some states Transmission loss and wheeling loss is also exempted
8.	Communication capability	MRI compatible; few states have asked for AMI compatible net meters
9.	Rate applicable in case of export to the grid	FiT, PPA rate or APPC (in most cases)
10.	Settlement period	Mostly one year; few states like Andhra Pradesh and Telangana have half-yearly settlement period. In most cases, the settlement year is financial year (April to March) except, Punjab and Sikkim where the settlement year starts from October.
11.	RPO compliance	Major states allow solar energy generated as part of RPO compliance; In case of Karnataka if the GRPV is DISCOM owned then total generation is considered under RPO compliance otherwise total energy purchased is considered
12.	Managing safety	Primarily responsibility of consumer, provisions for auto-shutting of solar plant when grid supplier fails is also provided

The detailed review of the state regulations and NEM regulation, 2013 is provided in the chapter 3 subsequently.

2.6 Scope and focus of the gap assessment report

Looking at the progress made so far in Grid connected rooftop solar segment, GRPV systems has not experienced significant growth rate as compared to ground mounted solar projects which gained attention of policy makers and other stakeholders. Cumulative Grid connected rooftop solar installations as of September, 2017 is 1861[15] MW vis-à-vis a cumulative installed solar capacity of 14,163 MW. Grid connected rooftop solar has maintained around 9-10% share in overall solar capacity. This is much lower than the developed countries like US, Germany, China, Spain and Australia.

In order to critically investigate the reasons behind the sluggish uptake, the existing policy gaps, operational challenges and foreseeing the market uptake trends need to be thoroughly examined.

Thus, it is necessary to review existing regulatory framework (model and state regulations), carry out stakeholder consultation for getting insights from their experience and to understand their expectations. Along with international desk research for development of business models that can be adopted in Indian context need to be studied. The outcome of these exercise also needs to be discussed with select stakeholders to prepare final report on comprehensive metering regulations and settlement mechanisms proposed for GRPV in India and draft GRPV metering regulations.

This report has been structured across five chapters. A brief of what each chapters covers is provided below:

- Chapter 1: Executive Summary of the gap assessment report is provided in chapter 1.
- Chapter 2: (present chapter): This chapter introduces the present policy and regulatory framework in India with focus on the regulatory framework that was adopted for enhancing the grid connected solar Grid connected rooftop solar in India. The development of GRPV system in India and ambitious target set is also discussed in this chapter. An assessment of the provisions in model regulations of 2013 and the policy framework that is followed in states for grid connected solar rooftop is also presented in this chapter.
- Chapter 3: This chapter focuses on the methodology that will be followed for identification of gaps that exists in the existing regulatory framework seen from the present position from where the sector needs to grow, the way GRPV system has seen proliferation in developed countries. The steps and the procedures will help in conducting a holistic study on finding the gaps and then finding a method to mitigate these gaps based on international experience.
- Chapter 4: This chapter would detail out the gaps that are evident in the present scenario considering all the technical as well as commercial parameters. The issues related to metering arrangement, accounting and commercial gaps, and business models which are hampering the development of grid connected solar Grid connected rooftop solar are also discussed in the chapter.
- Chapter 5: This chapter would focus on the global scenarios of different countries like U.S., Canada, and Germany etc. Their rich experience in large scale deployment of GRPV systems will provide a way forward for India to adopt the scenarios which are best suited for successful implementation of grid connected solar rooftop. This includes regulatory framework, business models and other aspects of grid connected solar rooftop.
- Chapter 6: This chapter will discuss the identified gaps and their proposed mitigation measures to be incorporated in the comprehensive model GRPV regulations based on international experience, discussed earlier, and recent cases seen in India.
- Chapter 7: Disclaimer

[15] *BTI Report September,2017*

Approach and Methodology

3 Our approach & methodology to conduct gap analysis of current regulation

Based on requirement of the project, the gap analysis has been carried out in following way:

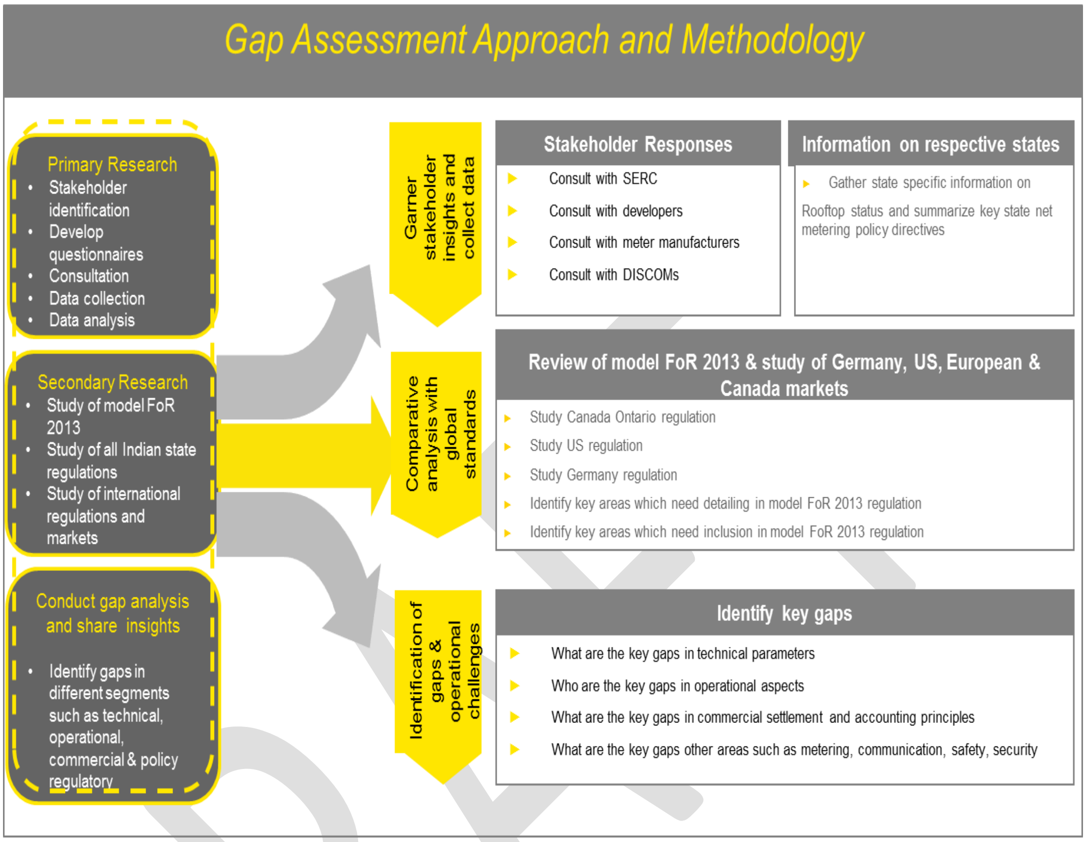

Figure 6 : Gap Assessment approach and methodology

1. Primary Research:

   Identification of key stakeholders is most critical in conducting primary research to identify key gaps in the current regulation. Following are the stakeholders consulted with to assess key challenges faced and understand their opinions on different clauses may be considered for inclusion in the upcoming regulation.

   - State Electricity Regulatory Commission (SERC)
   - Distribution Companies
   - Project Developers
   - Meter Manufacturers

Based on the existence of private & government utilities, varying Grid connected rooftop solar status across different states following stakeholder consultation plan has been developed.

<u>DISCOMs & SERCs:</u>

Table 7 : Stakeholder Interactions

Sr. No.	States	Stakeholders Interacted with
1.	Bihar	BERC, SBPDCL
2.	Chhattisgarh	CSERC, CSPDCL
3.	Delhi	DERC and BSES

Sr. No.	States	Stakeholders Interacted with
4.	Gujarat	GERC and Torrent Power
5.	Karnataka	KERC, BESCOM
6.	Maharashtra	MERC, Tata Power
7.	Odisha	OERC and CESU
8.	Rajasthan	RERC, Jaipur DISCOM
9.	Uttarakhand	UERC , UPCL
10.	West Bengal	WBERC and CESC

Meter Manufacturers:

Table 8: Meter Manufactures

Sr. No.	Company
1.	Secure Meters
2.	Zen Meter

Project Developers:

Table 9: Project Developers

Sr. No.	Company
1.	Distributed Solar Power Association, National Capital Region (NCR)

2. Secondary Research:

- The detailed review of the NEM 2013 to identify the gaps to mitigate was undertaken as a first task. Secondary research was conducted based on key considerations in NEM 2013 listed below:
    a. Metering requirements such as MRI, supply code compliance, solar meters etc.
    b. Business model such as contractual & connection agreements and beneficiaries responsibilities
    c. Institutional roles and responsibilities
    d. Data communication and retrieving mechanism
    e. Energy accounting
    f. Restrictions on level of overall or local grid penetration
    g. Permitting limits on individual projects & commercial settlement mechanism
    h. Maximum rated capacity for a Grid connected solar Grid connected rooftop solar project for interconnection with the grid at a specific grid voltage level
- Thereafter, consultative meetings with select developers, meter manufacturers, state regulators and state DISCOMs were conducted.
- Conducted a comparative analysis between states and develop procedures, formats/frameworks for addressing the following.
    a. Modality of data record, data management including archival and MDAS.
    b. Communication protocols and infrastructure requirement
    c. Adjustments of the billing systems such as AMR and Manual reading

d. Ownership of meters
e. Procurement procedures
f. Warehousing & distribution
g. Testing procedures & principles
h. Billing procedures
i. Grievance management

- Evaluation of gaps in implementations of grid interconnection of GRPV across the select states.
    a. Technical standards as per supply voltage and state supply code
    b. Safety & Supply
    c. Power quality including harmonics, voltage, synchronization, flickers, DC injections, frequency etc.
- Conducted international review of the various operating business prevalent in countries with large GRPV penetrations and performed comparative assessment with respect to Indian scenario to identify best practices.
- The impact of grid connected solar rooftops in DISCOM business models through appropriate modelling and quantitative assessments will be assessed separately.
    a. Assessment of all potential business models possible for grid connected solar rooftop; global and local practices
    b. Assessment of Impact on DISCOM revenue. Case study of 2 DISCOM (rural and urban)

3. Different scenarios has been developed based on emerging business models; including energy service models and behind the meter business universe) considering changing economic scenario and macroeconomic parameters including changes in global energy sector.
4. Developed assessment methodology for DT capacity for streamlining the processes for net metering application.
5. Developed critical requirement to address interconnection requirements and challenges.
6. Developed recommendations on the metering regulations and accounting mechanisms for various operating business models. This will include self- consumption framework and other metering such as gross, net, community and virtual.

Way ahead

1. Four workshops will be conducted for disseminating the results and outcomes.
    a. Conduct workshop with State stakeholders (DISCOM, SERC and developers, Suppliers) and seek their views or comments.
    b. Assist FOR addressing stakeholder comments.
2. After incorporating stakeholder comments final report on comprehensive metering and accounting framework will be prepared.
3. Draft model regulation will be submitted to FOR to garner their feedback and submit the final model regulation.

Review of Current Regulations

4 Review of present regulatory framework

4.1 Review of existing regulatory framework

As mentioned earlier, the present regulatory framework is focused on self-consumption and therefore the provisions of model regulation, 2013 and that of state regulations has put certain restrictions in terms of system capacity that an individual can install, how much capacity can be allowed on single DT and maximum capacity that can installed by individual consumer.

4.1.1 NEM Regulation, 2013

The Key snapshots of the NEM regulation, 2013 has been provided below:

Scope and application falling under net metering ambit:

1. All consumers with systems which are
   - Within the permissible capacities
   - Located in the consumer premises
   - Interconnected and operate safely with the distribution network may install Grid connected rooftop solar systems under net metering.
2. The regulations do not preclude the right of the state authorities from installing Grid connected rooftop solar projects with capacities greater than 1 MWp through alternate mechanisms.

General principles:

1. The Distribution Licensee (DL) shall offer net metering arrangement to the consumers on a non-discriminatory and first-come-first-serve basis provided that the distribution licensee provides the net metering arrangement under the regulations and the consumer is eligible for installation of the mentioned capacity under the regulations.

Capacity targets:

1. The DL shall provide net metering arrangement to the eligible consumers till the total installed capacity does not exceed the maximum cumulative capacity (to be decided by SERC) allowed to consumers under net metering in the area of supply. The cumulative capacity allowed for interconnection shall not exceed 15% of the peak capacity of the DT.
2. The DL shall update yearly on their website the capacity available for interconnection under net metering arrangement at the DT level.

Eligible consumers and individual project capacity:

1. The installed capacity shall be governed by the eligibility of the consumer for interconnection. The maximum installed capacity shall not exceed 1 MW.

Interconnection with the grid:

1. The interconnection with the distribution grid shall be made as per the technical standards notified by the competent authority. A variation of +/- 5% is allowed in the system capacity.

Energy accounting and settlement

1. For each billing period, the licensee shall show the following:
   - Electricity injected
   - Electricity consumed
   - Net billed electricity
   - Net electricity carried over to the next billing cycle
2. If the electricity injected exceeds the electricity consumed during the billing period, the excess electricity is carried forward to the next billing period.
3. If the electricity consumed exceeds the electricity injected during the billing period, the net electricity consumed is billed by the distribution licensee.

4. If time of day tariffs are applicable for the consumer, the electricity consumption in any time block will first be compensated with electricity generation in the same time block. Any excess generation over the consumption in any other time block will be accounted as if the excess generation occurred during the off-peak time block.
5. Excess generation may only be utilized for off-setting consumption and may not be utilized for compensating other fees and charges imposed by the distribution licensee.
6. The electricity generated shall not be more than 90% of the electricity consumption at the end of the settlement period. No payment shall be made by the DL to the consumer and also the generation will not be carried forward if the generation exceeds 90%. At the beginning of each settlement period, the cumulative carried over injected electricity will be zero.

Solar renewable purchase obligation

1. The quantum of electricity consumed by a non-obligated entity from a Grid connected rooftop solar system shall qualify towards compliance of RPO for the DL.

Applicability of other charges

1. The Grid connected rooftop solar systems are exempted from banking, wheeling and cross subsidy charges.

Metering arrangement

1. The net meters shall be of accuracy class 1.0 or better. The main solar meters shall be of 0.2s class accuracy. The meters shall be Meter Reading Instrument (MRI) compliant. Check meters shall be mandatory for Grid connected rooftop solar systems with capacity greater than 20 kW.
2. The installed meters have to be jointly inspected and sealed on behalf of both the parties and shall be interfered/tested only in the presence of both the parties – consumer and the distribution licensee.

4.1.2 State regulations for solar roof-top

Following the model NEM regulations, different states started issuing their own state regulations. Structurally, the state regulations revolved around the NEM regulation, 2013, such as:

1. System size, limit on DT capacity and maximum size allowed
2. Metering schemes
3. Energy accounting and commercial settlement, and
4. Regulatory provisions related to RPO

System size, limit on DT loading and maximum size

The maximum capacity allowed in state is 1 MW, same as model net metering regulation, 2013 (except, in states and UTs regulated by JERC where it is 500 KW). The Grid connected rooftop solar projects of ratings higher than 500 KWp can be considered by the Distribution Licensee if the distribution system remains stable with higher rating Grid connected rooftop solar Projects getting connected to the grid16. The summary of provisions related to system sizes, system capacity allowed in percentage loading on DT and exemption allowed from different charges for various states is provided in the table below:

[16] http://jercuts.gov.in/writereaddata/UploadFile/SPGREGULATIONFINALJUNE_1848.pdf

Table 10 : Constraints on capacity of solar plants in states.

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
1.	Tamil Nadu	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size < 100% sanctioned load ▶ Cumulative capacity installed < 30% of DT capacity in the area	Wheeling and cross subsidy surcharge
2.	Maharashtra	▶ Capacity < 1MWp (with a variation of 5%) ▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 40 % of DT in the area	Banking, wheeling & cross subsidy charges
3.	Gujarat	▶ Capacity < 1 MWp ▶ Maximum plant size < 50% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 65% of DT capacity, in the area	Transmission Charge, Transmission Loss, Wheeling Charge, Wheeling Loss, Cross Subsidy Surcharge, Electricity Duty
4.	Uttar Pradesh	▶ Capacity: 1kWp - 1MWp ▶ Maximum plant size <100% of sanctioned Load ▶ Cumulative capacity of solar systems in the area < 15% of DT capacity	Wheeling & cross subsidy surcharge if applicable
5.	Karnataka	▶ Maximum plant size < 150% of sanctioned load ▶ Limits of solar systems: Up to 1MWp for HT consumers, Up to 50 kWp for 3 phase LT Consumers	Wheeling, banking, cross subsidy charges if applicable, VAT
6.	Rajasthan	▶ Capacity: 1 kWp - 1MWp ▶ Maximum size< 80% of sanctioned Load ▶ Cumulative capacity of solar systems installed in the area < 30% of DT capacity in the area	Banking, wheeling & cross subsidy charges
7.	Andhra Pradesh	▶ Capacity <= 1MW ▶ Cumulative capacity of all solar systems installed in the area < 60% of Local DT capacity at LT level and 100% at HT level	Distribution losses and charges
8.	Telangana	▶ Capacity< 1MWp ▶ Cumulative capacity of all solar systems installed in the area < 50% of Local DT capacity at LT level	Distribution losses and charges, Electricity duty, Cross subsidy surcharge, VAT
9.	Delhi	▶ Capacity 1kWP - 1MWp ▶ Maximum plant size <100% of sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity in the area	Banking, wheeling & cross subsidy charges

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
10.	Haryana	▶ Capacity < 1MWp ▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity	Banking, wheeling & cross subsidy charges
11.	Andaman & Nicobar Islands	▶ System Size: Min 1 kW; > 500 kWp ▶ Cumulative capacity of all solar systems installed in your area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
12.	Assam	▶ Capacity: 1 kWp - 1MWp ▶ Maximum plant size <40% of Sanctioned Load	Wheeling & cross subsidy charges
13.	Bihar	▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area ▶ < 15% of DT capacity ▶ Electricity generated by the Grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	Wheeling & cross subsidy charges
14.	Chhattisgarh	▶ Capacity: 50 kWp – 1 MWp ▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 40% of DT capacity	N/A
15.	Goa	▶ System Size: 1 kW – 500 kW ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
16.	Himachal Pradesh	▶ Size: 1 kWp – 1 MWp ▶ Voltage Level 1. 230 V (Single Phase): up to 5 kWp 2. 415 V (Three phase): up to 15 kWp 3. <11kV: 1 MWp max ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
17.	Jammu & Kashmir	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <50% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 20% of DT capacity	Various Intrastate Open Access charges
18.	Jharkhand	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 15% of DT capacity	Wheeling & cross subsidy charges
19.	Kerala	▶ Capacity: 1 kWp – 1 MWp ▶ capacity of all solar systems installed < 30% of DT capacity	Banking, wheeling, cross

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
			subsidy charges and electric duty
20.	Lakshadweep	▶ Capacity: Min 1 kW, > 500 kWp ▶ capacity of all solar systems installed < 30% of DT capacity	Banking, wheeling and cross subsidy charges
21.	Madhya Pradesh	▶ Maximum plant size <50% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity	banking, wheeling, cross-subsidy surcharges & electricity duty, no liability of property tax, exempted from VAT and entry tax
22.	Manipur	▶ Capacity: 1 kWp – 500 kWp ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity	Banking charge and cross subsidy surcharge
23.	Meghalaya	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity ▶ Electricity generated by the Grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	N/A
24.	Odisha	▶ Capacity: 1 kWp – no cap on upper limit. ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity ▶ Electricity generated by the Grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	N/A
25.	Punjab	▶ Size: 1 kWp – 1 MWp ▶ Voltage Level 1. 230 V (Single Phase): upto 5 kWp 2. 415 V (Three phase): upto 15 kWp 3. <11kV: 1 MWp max ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Wheeling & cross subsidy charges
26.	Sikkim	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <80% of Sanctioned Load	Banking charge and cross subsidy surcharge
27.	Tripura	▶ Capacity: 1 kWp – 1 MWp	Banking, wheeling, cross

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
		▶ Maximum plant size <100% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed < 15% of DT capacity	subsidy and other charges
28.	Uttarakhand	▶ Size: 1. with battery backup: 300 Wp – 100 kWp 2. Without battery backup: upto 500 kWp ▶ Voltage Level 1. 230 V (Single Phase): upto 4 kWp 2. 415 V (Three phase): 75 kWp 3. 11kV: 1.5 MWp max 4. >11 kV: 3 MWp max. ▶ Maximum plant size <80% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 30% of distribution	Wheeling & cross subsidy charges
29.	West Bengal	For institutional: ▶ Capacity > 5 kWp ▶ Mandatory for all existing and upcoming schools and colleges having a total contract demand of more than 500 kW will be required to install solar Grid connected rooftop solar systems to meet at least 1.5% of their total electrical load ▶ Electricity generated by the Grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period. For residential & Commercial: ▶ Mandatory for all large housing societies having a total contract demand of more than 500 kW will be required to install solar Grid connected rooftop solar systems to meet at least 1.5% of their total electrical load	Wheeling & cross subsidy charges

Metering principle: Gross metering and net metering

Most of the states have adopted net metering principle. Karnataka has adopted gross metering for residential customers and net metering for Commercial & Industrial customers. West Bengal has made net metering compulsory for education institutions and also provisioned for gross metering for other consumer categories along with net metering. The Joint Electricity Regulatory Commission has also adopted gross metering and net metering for or entity or a house/ factory / Ware house / Government building / Panchayat Bhavan / Community centre/ School/ dispensary / hospital / parking Shed or place/ a solar plant on elevated structure / Group housing society / Resident welfare society/ market roof top or any such entity, based on the technologies approved by Ministry of New & Renewable Energy of Government of India. Andhra Pradesh and Telangana ERCs has also allowed gross metering as well as net metering for all consumer.

Business models

In line with the NEM regulation, 2013, all state regulations has considered two consumer centric models; CAPEX model and RESCO models. The definition of the consumer, eligible consumer, and premise are defined according to these model only. Internationally, DISCOM Centric models where DISCOM is leading the investment, O&M part are very much popular. Other models like community and virtual models, where different consumers are coming together to develop solar roof-top system are also prevalent. In California, Solar service model is prevalent, especially, in residential segment in California due to Zero Down payment, long lease of 20 years and buy back option to consumer.

Accounting and commercial settlement

Presently, many states has adopted settlement cycle of one year, same as NEM regulation 2013 except Telangana, Andhra Pradesh and states & UT's under JERC. In Telangana and Andhra Pradesh unadjusted net credited Units of electricity are settled twice in a year viz., in June and December. In Goa and other UTs Settlement Period is from 1 April to 30 Sept and 1 Oct to 31 March. To appropriately cover the impact of seasonality solar generation, NEM regulation 2013 considered settlement period of one year. As per clause 8.2 of Model regulation 2013, the electricity generated by the Grid connected rooftop solar system of an eligible consumer should not be more than 90% of the electricity consumption by the eligible consumer which is settled at the end of the settlement period of one year which is possible only after completion of one year. However, net excess generation if any during a control period is not either compensated or allowed to carry forward in next settlement period.

State wise accounting and commercial settlement mechanism is provided in the table below:

Table 11 : Accounting and Commercial Settlement

Sr. No.	Particulars	Name of the states having these provisions
	In case of net excess generation	
1.	Excess generation allowed to carry forward in next settlement period	Bihar
2.	Excess generation not allowed to carry forward in next settlement period	Delhi, Haryana, Madhya Pradesh, Tamil Naidu.
3.	Excess generation settled at the end of financial year or settlement period at APPC	Gujarat, Maharashtra, Telangana, Andhra Pradesh.
4.	Excess generation settled at the end of financial year or settlement period at FIT	Rajasthan
5.	Excess generation settled at the end of financial year or settlement period at generic tariff	Karnataka, Kerala, Orissa,

Regulatory provisions related to RPO

In terms of RPO compliance, in line with the NEM regulation, 2013 most of the states treat total electricity consumed from the solar system under net metering towards compliance of RPO for the distribution licensee provided the renewable energy generator is not an obligated entity under the SERCs.

Global Experience in GRPV deployment

5 Global experiences in GRPV segment

In recent years, net metering has become one of the most important promotion schemes for distributed renewable energy generation, most notably GRPV systems. As of May 2015, 48 countries worldwide had implemented net metering schemes, in most of the cases on a national level. Net metering became the incentive policy choice in 26 countries since 2012, when around 22 countries had adopted net metering schemes.[17] From a macro perspective, net energy metering is a widespread promotion scheme in the Americas (19 countries have adopted net metering schemes) as well as for smaller islands states (9 countries). In Europe, net metering applies only in 9 countries. Australia, Japan and the U.S. can be considered as the net metering front runners, where early net metering regulation already led to substantial installation figures.

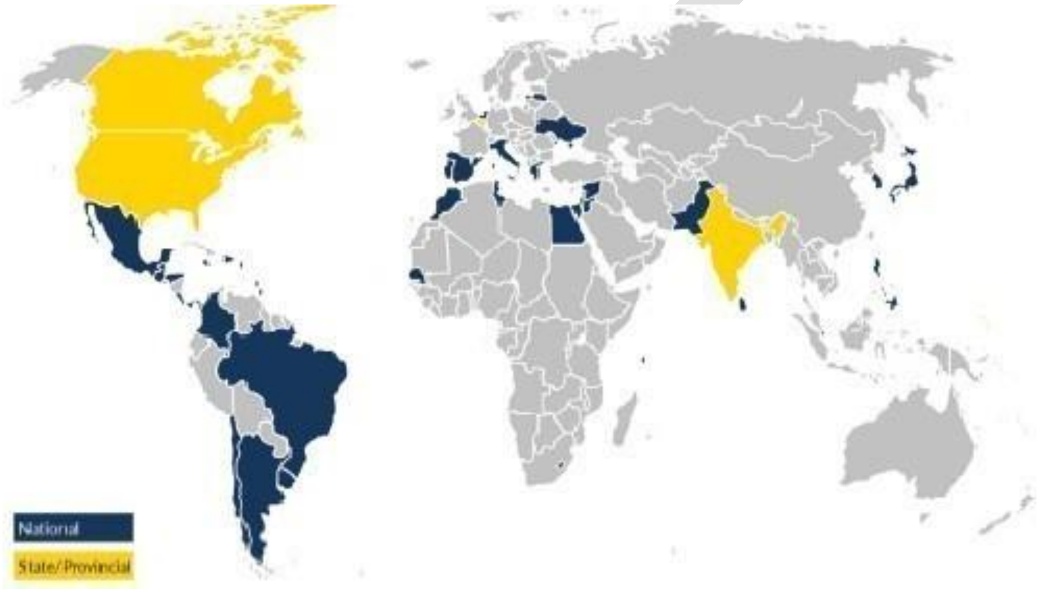

Figure 7 : Countries with net metering

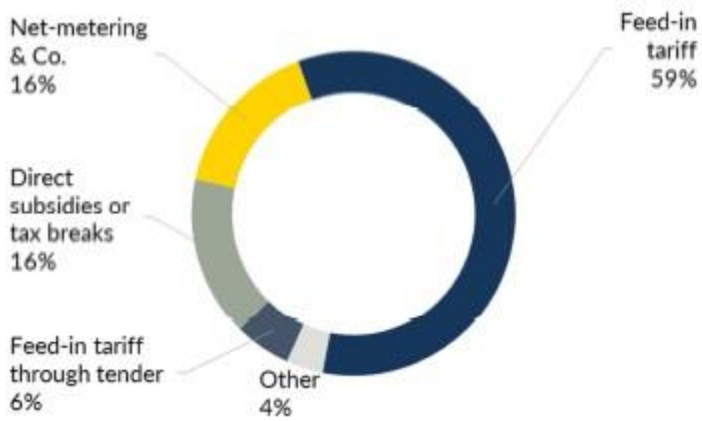

Figure 8 : Global share of GRPV policy drivers

[17] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

Globally, net metering and other forms of subsidized self-consumption accounted for 16% of the world market. However, the main promotion scheme for renewable energy sources remains the feed-in tariff, it accounted for almost 60% of newly installed GRPV capacity in 2014.[18]

As part of the study, developed countries with higher GRPV penetration like US, German & Canada experiences has studied to understand key trends, prevalent business models, settlement mechanisms and emerging features to learn and assimilate new ideas that might be applied in India for GRPV proliferation.

5.1 Key features of California NEM regulation

California is one of the major solar market in USA. In 1995, California introduced net metering scheme for distributed electricity generation. It has seen cumulative capacity addition of 11 GW[19] of GRPV power plants in the state. In 2014, 614 MW of GRPV systems were installed by 4.5 lakhs electricity consumers[20]. The regulatory framework in California promoted net metering and offers credits retail rates to residential and small commercial PV plant owners. Gross metering is also available in California.

5.1.1 California's Net-Metering Policy key features

- California's net metering to receive bill credits for the excess electricity that their solar panels produce, as long as the system is less than 1,000 kilowatts (1 MW).
- California's first net metering policy set a "cap" for the three investor-owned utilities in the state: Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE).
- Total solar installations in each utility's territory were capped at five percent of total peak electricity demand.
- To ensure that solar would continue to succeed, the California Public Utilities Commission (CPUC) created a next-generation program known as "Net Metering 2.0" (NEM 2.0) that extends California net metering benefits for years to come.
- Under California NEM 2.0, residential and small commercial system owners pay a small one-time "interconnection fee" to connect their solar panels to the electric grid. For SDG&E customers, the fee is $132, and PG&E customers will pay $145.
- NEM 2.0 enrolment for PG&E, SCE, and SDG&E customers starts after each utility reaches its original net metering cap or by July 1, 2017 – whichever happens first[21].
- The are many exceptions but, in general, the current rules allow on-site energy projects of up to 1 MW access to net metering.

5.1.2 Regulatory interventions

California's original net metering regulation was enacted in 1996 and subsequent amendments have increased the eligible technologies and established fee structures, resulting in the current comprehensive system. All utilities are subject to net metering rules except publicly-owned utilities with 750,000 or more customers that also provide water (only the Los Angeles Department of Water and Power fits this description). Publicly-owned utilities can choose to incorporate a time of use (TOU), same as time of day terms used in India, rate schedule for net metered consumers. Customers retain ownership of all RECs except for excess generated exported.

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[18] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

[19] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

[20] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

[21] *As of January 2018, the status for each utility is as follows:*
SDG&E: Net metering reached its cap in the summer of 2016, which means that new San Diego solar system owners are currently enrolling in net metering 2.0.
PG&E: PG&E reached its net metering cap on December 15, 2016. All new PG&E solar customers are being enrolled in NEM 2.0.
SCE: The original SCE net metering program reached its cap in summer 2017, and all new solar customers will enrol in NEM 2.0.

Furthermore, no additional charges or fees are allowed. Beginning in 2009, California was also one of the first states to allow virtual net metering for multi-family affordable housing units and municipalities. In 2010, the aggregate net metering limit was raised to 5.0% of the utility's aggregate customer peak demand. California's Rule 21, adopted in 2000, governs the U.S. distributed generation interconnections due to the impact of California's solar incentives and various state policies related to distributed generation. Rule 21 is significantly different from the FERC standards, as it follows the same review process regardless of the size of a proposed generator. All interconnections start with an initial review, which applies eight screening criteria to determine whether a generating facility qualifies for a simplified interconnection and therefore does not include separate levels of interconnection. Rather, all applications enter the process at the same point and then "drop out" according to complexity.

As more users are going for GRPV installations, the main utilities in California, Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDGE) have periodically raised concerns over the future financing sources for grid infrastructure.22 The Californian utilities PG&E and SDGE insisted on getting a fixed monthly rental and also lowering the payment done to the net metering consumers. In 2015, SDGE analysed an increase in the cost that non solar consumers had to bear. They estimated $ 160 billion23 additional cost for non-solar consumers. This has pushed various net metering reforms as the old incentives for grid connected solar rooftop would increase the bills for non-solar consumers.

The California public utilities commission (CPUC) decided for reform in residential tariff structure as tariffs were not changed since 2001 energy crisis. The tariff that existed were complex and misaligned. In perspective of net metering, TOU tariffs were introduced which encouraged lower consumption when the electricity rates are high and the extra solar energy is more valuable to sell when the electricity demand is high. CPUC decided that utilities should design the TOU pilots and by 2019 default TOU rates should be applied on all consumers. The tariff reforms were argued by the utilities and requested for a monthly rental from the grid connected solar rooftop owners. Therefore the commission agreed a minimum bill for the residential grid connected solar rooftop owners will pay at least $ 10 a month or $ 5 for low income households.

In 2016, CPUC maintain the same retail rate for net metering. The solar consumers were not obliged to pay transmission charges however they will have to pay a "non – by passable" charges for consuming from the grid. This amount would not include the amount of energy exported to the grid. These charges will help in efficiency programs and funding. The GRPV system customers would be mandated to TOU tariff which would be identified in electricity tariff reform. The existing net metering customers would receive remuneration schemes through a 20 year period.

Metering Principle

Net metering principle is adopted in California to promote self-consumption in all categories with several other incentives like Property Tax exemption, California Solar Initiative – fully/partially and performance Based Incentives to builders. To promote GRPV in residential consumers, especially, low income group subsidized PV systems were made available.

Capacity Limits & Interconnection Voltage

Presently, GRPV systems up to maximum 10 MW are allowed in California[24]. Earlier, it was 5 MW for system installed by Local government or university whereas for others the restriction was 1 MW only.

In India, present net metering regulations allows Distribution Licensee, or state government departments to install GPRV projects more than 1 MW through alternate mechanism. RE generators with capacity of 1 MW and above to whom net metering dispensation is not available can otherwise

[22]https://www.international-climate-initiative.com/fileadmin/Dokumente/2016/160223_Regulatory_Trends_NetMetering_eng.pdf

23 Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates

[24] Best Practices in State Net Metering Policies and Interconnection Procedures. Freeing the grid.

avail open access. Also, in case of RE generators, gross metering (preferential tariff) dispensation is available for solar PV and other RE projects with capacity of 1 MW and above.

Therefore, if technically feasible, more capacity under net metering can be allowed in India, depending upon consumer demand vs capacity possible; appropriate metering principle and commercial settlement. Further option can be explored if capacities under 1 MW can be allowed on gross metering basis for self-consumption and third part sale.

5.1.3 Business Models

Similar to present models in India, self-owned and third party model were popular at early stage of grid connected solar rooftop deployment. However, other business models such as virtual net metering, community solar & utility led aggregator models have become sporadically popular since 2003 which can be adopted in India as next step for proliferating GRPV systems on large scale.

In case of California, in case of renewable energy sources, energy corporations are exempted from the need for a supply license to supply a maximum of two consumers located on the same property from any open access. In India, to promote GRPV system in residential categories, to some extent pear to pear transaction needs to be allowed where the consumer can avail.

5.1.4 Energy accounting and Commercial settlement

In California Net Energy Metering was adopted in 1995 which stated that in addition to the self-consumption, when exporting electricity to the grid, prosumers receive energy credits, valued by the full electricity retail rate, which are deducted from monthly gross consumption, so the prosumer is just charged for its net consumption. At the end of the 12-month period, if there was a net excess generation, the utility purchased the credits at the avoided costs. Otherwise, the prosumer was billed for the net energy supplied at the prosumers “standard rate”.

The regulation was modified in 1998, when the policy was extended to small commercial customers and small wind turbines. In 2000, Assembly Bill (AB) 918, was approved, and the main change was regarding the method of charging prosumers’ net consumption at the end of each 12-month period. While the previous law required that the compensation owed to the utility was based on the average retail price per kWh for the prosumer’s rate class, AB 918 introduced a scheme of “baseline” and “over-baseline” tariffs, and also created the possibility of charging net consumption according to time-of-use tariffs, in cases in which consumers migrated to this kind of rate.

In 2001 the bill was modified and the installed capacity cap was increased to 1 MW and commercial, industrial and agricultural customers also became eligible to the scheme.

In 2009, an important bill (AB 920), regarding the treatment of net excess generation, came into effect. According to the previous bill, at the end of the 12 months billing period, also known as the true-up period, no compensation was owed to the eligible customer in case of net excess generation, unless the utility decided to enter into a purchase agreement with the customer for purchasing this electricity .At the end of the true-up period, if the consumer had exported to the grid more electricity than he imported from the grid, so he can choose to receive a payment proportional to the net excess generation.

A new revision came into effect in 2013, when bill AB 327 was signed, redefining the system level capacity cap to 5% of the investor owned utilities peak demand. The bill also allowed utilities to charge a monthly fixed charge of $10 for all residential customers, except low income ones, who are charged a $5 fee. The fixed charge was supposed to enable utilities to recover fixed costs that are not covered by prosumers, in order to mitigate the cost shifting issue.

In June 2016, CPUC revamped the NEM with 2.0 version which highlighted the following points:

- Interconnection fee: customers who install photovoltaic systems will have to pay a pre-approved interconnection fee, proposed by the utilities, based on the historical interconnection costs. It is likely to be around $75-$150;

- Non-by passable charges: prosumers will have to pay non-by passable charges, of approximately 3 cents, per kWh consumed from the grid, independently of how much electricity was exported to the grid;
- Time-of-use tariffs: prosumers will have to adopt time-of-use tariffs, as soon as they are available, in order to promote the electricity consumption rationalization, as ToU tariffs better reflect generation costs along the day.
  Elimination of the 1 MW maximum system size to promote more and more net metered consumers.

The trends in GRPV deployment in California are shown in the following table:

Table 12: California trends in grid connected solar rooftop

Sr. No.	Particulars	1995	1998	2001	2002	2013	2016
1.	System capacity cap	10 kW	10 kW	1 MW	1 MW	1 MW	N/A
2.	Consumption class	Residential	Residential and small commercial	Residential, commercial, industrial and agricultural	Residential, commercial, industrial and agricultural	Residential, commercial, industrial and agricultural	Residential, commercial, industrial and agricultural
3.	Compensation period	12 Months	12 Months	12 Months	12 Months	12 Months (Extendable to 24 months)	12 Months (Extendable to 24 months)
4.	Treatment of net excess generation (NEG)	NEG purchased at avoided costs	No compensation (unless a purchase agreement is signed by the utility)	No compensation (unless a purchase agreement is signed by the utility)	No compensation (unless a purchase agreement is signed by the utility)	Net Surplus Compensation (NSC): 12-month rolling average of retail rate	Net Surplus Compensation (NSC): 12-month rolling average of retail rate
5.	Utility territory caps	0.1% of utility's aggregate peak demand (as of 1996)	0.1% of utility's aggregate peak demand	N/A	0.5% of utility's aggregate peak demand	5% of utility's aggregate peak demand	N/A

5.1.5 Key takeaway

The key takeaways from California State are summarised below:

- Higher system capacity (more than 1 MW) can be allowed depending upon the consumer category, their demand and technical feasibility of interconnection.
- As the purpose of net metering regulation is to promote self –consumption it can be achieved where consumer demand is high and generation from higher GRPV capacity can be absorbed by the consumer itself at single location.
- The issue of cost of upgrading infrastructure will also arise when higher capacity is allowed which needs to be either recovered from consumer or shared by DISCOM and consumer depending upon the up gradation required.
- Excess generation, if any, after settlement period should be compensated at reasonable rate. In many cases, no payment is done for the excess generation.
- Different business models as per consumer needs can be allowed

5.2 Key learning from other states of USA

5.2.1 Interventions in developing GRPV market

USA has been one of the leading markets in net metering with 48 states undertaking net metering incentive schemes. This evolution has happened after facing several debates followed by amendments in the incentive scheme. As the market for solar roof-top evolved, further interventions at policy level and regulatory level were required to protect the DISCOM interest and also to amend the solar regulations based on experience gained Some of these key activities undertaken by several states are listed below:

- Tariff re-design; from volumetric to fixed cost based
- Relaxing limits on system size
- Assessment of revenue impact
- Development of emerging models; DISCOM led business model, community solar and third party sale

5.2.2 Regulatory interventions

In 2013-14, there was constant debate by the utilities as the net metering policies were impacting their revenue streams. Utilities were campaigning against the grid connected solar rooftop and they stated that the grid connected solar rooftop PV owners are like "grid free riders". The system and grid costs were getting unevenly distributed between the solar households and the non-solar households.

The following states of US started taking following actions to overcome the above protest by the utilities:

Table 13: USA - State Reforms

Sr. No.	U.S. States	net metering regulation changes	Electricity tariff reform	Analysing the value of distributed solar along with revenue impact on utilities
1.	Arizona	✓	✓	✓
2.	California	✓	✓	
3.	Hawaii	✓		
4.	Maine	✓		✓
5.	Massachusetts	✓		
6.	Nevada	✓		
7.	South Carolina	✓		✓
8.	Wisconsin		✓	
9.	New York	✓		

The states have decided to change their net metering regulations which would limit the consumers on their generation as well as consumption from the GRPV systems. On tariff front, the policies and regulations were envisaged to balance the interest of both; utilities as well as consumers.

The summary of policy actions[25] are provided in the table below:

Table 14 : Summary of policy actions in states of USA

Sr. No.	Policy type	Actions undertaken by states	Percentage completed by states	No. of states involved
1.	Residential fixed charge increase	26	29%	18
2.	Net metering	22	24%	19
3.	Residential solar/DG charge	14	15%	10
4.	Solar valuation or net metering study	13	14%	12
5.	Community solar	5	5%	5
6.	Utility-led rooftop PV programs	5	5%	4

[25] *US NEM Best Practices UEG 2013*

Sr. No.	Policy type	Actions undertaken by states	Percentage completed by states	No. of states involved
7.	Third-party ownership of solar	4	4%	4
8.	Minimum bill increase	2	2%	2

In USA, total 19 states have come up with changes and interventions in their net metering policies. Massachusetts, New Hampshire, New Jersey, New York and Nevada are the states which are accommodating new system. Some of such actions proposed by DISCOMs and approve by respective Commission in relation with net metering are given below[26]:

Table 15 : Interventions in net metering in states of USA

Sr. No.	State	Type of change	Description
1.	California	Net Metering Rules, Aggregate Cap, Net Excess Generation	▸ The present NEM program went into effect in SDG&E's territory on June 29, 2016, in PG&E's territory on December 15, 2016, and in SCE's territory on July 1, 2017. The program provides customer-generators full retail rate credits for energy exported to the grid and requires them to pay a few charges that align NEM customer costs more closely with non-NEM customer costs. ▸ In August 2015, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) proposed successor net metering tariffs .A net metering successor tariff will take effect for the three IOUs on July 1, 2017, or when 5% of the sum of non-coincident customer peak demand is reached for the IOU, with translates to an installed capacity of 2,409 MW (PG&E), 2,240 MW (SCE), and 617 MW (SDG&E) of net-metered systems. ▸ The successor tariff will not apply to customers entering into a net metering agreement before the existing cap or end date is reached. ▸ PG&E had proposed a demand charge and lower TOU energy charges, compensating exports to the grid at the energy portion of the generation rate (average of $0.097) rather than the retail rate (average of $0.163), and a monthly true-up of charges and credits. ▸ SCE proposed compensating customers via an on-bill credit at a rate of $0.08 per kWh rather than at the retail rate (average of $0.15 per kWh) for any electricity instantaneously exported to the grid and adding a monthly Grid Access Charge based on system size. ▸ SDG&E proposed a Default Unbundled Rate Option that features a special monthly fixed charge called a System Access Fee, a Grid Use Charge based on a customer's non-coincident monthly demand, and compensating energy exported to the grid at a rate of $0.04 per kWh. Alternatively,

[26] *50 states of solar – A quarterly update on US distributed generation policies*

Sr. No.	State	Type of change	Description
			customers could opt for a Sun Credits tariff option that is a buy-all, sell-all arrangement. ▸ The Office of Ratepayer Advocates proposes keeping net metering, but implementing a charge on new solar customers. The monthly charge would start at $2 per installed kW of PV once the existing net metering cap or end date is reached. When a utility's aggregate customer peak demand reaches 6% and 7%, respectively, the charge would increase to $5 per kW and $10 per kW.
2.	Hawaii	Net Metering Rules, Net Excess Generation	▸ In August 2014, Hawaiian Electric Companies (HECO) proposed a Distributed Generation Integration Plan that was deemed insufficient by the Public Utilities Commission in March 2015. In June 2015, HECO proposed a new plan that would increase minimum bills and reduce net metering compensation from $0.295 per kWh to $0.18 per kWh for HECO (Oahu) customers, from $0.359 per kWh to $0.225 per kWh for HELCO (Big Island) customers, and from $0.351 per kWh to $0.231 per kWh for MECO (Maui, Molokai, and Lanai) customers.
3.	Illinois	Net Metering Rules, Meter Aggregation	▸ In April 2015, the Illinois Commerce Commission (ICC) initiated a rulemaking proceeding on the state's net metering rules. The proposed rule adds new, clarifying definitions, enables web-based electronic application procedures, and requires a case-by-case consideration of meter aggregation by the utility and an explanation by the utility to the ICC if the request is denied. The proposed rules also align ICC net metering rules with previously enacted legislation. In Q3, intervening parties submitted reply comments.
4.	Iowa	Net Metering Rules	▸ In June 2015, Eagle Point Solar filed a complaint with the Iowa Utilities Board, seeking a ruling that i. Net metering a system financed by a third party does not constitute a "resale" of energy and ii. Large General Service customers (i.e., customers that have a demand charge) of Interstate Power and Light (IPL) are eligible to net meter. Eagle Point Solar alleged that IPL "will take the position that any energy flowing from the solar array under a net metering arrangement is a 'resale' of energy in violation of their tariffs" if a third-party power purchase agreement (PPA) is used. ▸ In July 2015, IPL began to offer net metering for solar PV systems using a third-party PPA for customers on its General Service tariff.

Sr. No.	State	Type of change	Description
			Customers on IPL's Large General Service tariff were ineligible for net metering, regardless of the system size or ownership arrangement. MidAmerican Energy, Iowa's other large IOU, does not currently offer net metering for systems financed through a third-party PPA.
5.	Maine	Net Metering Rules, Net Excess Generation	▸ The Maine Public Utilities Commission opened a docket in July 2015, pursuant to LD 1263, to investigate the potential for an alternative to net metering in the state. The Commission is responsible for convening a stakeholder group to develop this alternative policy. The Commission allowed interested parties to submit notification of their intent to participate in this group and to submit proposed topics for discussion by September 3, 2015. A report is due to the legislature by January 30, 2016. ▸ The Commission has adopted amendments to the net energy billing rule to promote the development and operation of small renewable generation facilities. ▸ Customers that own or have an interest in an eligible generation facility are billed for electricity on the basis of "net energy" over a billing period. Net energy is defined in the existing rule as the difference between the kilowatt-hours (kWh) a customer consumes and the kWh produced by that customer's generating facility over a billing period.
6.	Massachusetts	Net Metering Rules, integration of net metering and storage projects	▸ In June 2015, Solar City submitted a request to the Department of Public Utilities (DPU) for an advisory ruling on the ability of a combined solar and storage project to net meter under current Massachusetts statutes and regulations. Solar City withdrew the petition in July 2015, because they were able to work with the net metering administrator to submit an application. However, National Grid submitted comments requesting the DPU to still address this question, as the company is unsure whether combined solar and storage projects are eligible net metering facilities. ▸ Solect Energy has been selected to install a total of 8.7 megawatts (MW) of solar panels across schools, non-profits and municipalities across the US state of Massachusetts ▸ Working in conjunction with Power Options, the region's largest energy buying consortium, Solect has already installed 4.2 MW and said it is on track to install another 4.5 MW under the state's solar energy renewable certificate (SREC-II) programme for a total of 8.7MW.

Sr. No.	State	Type of change	Description
7.		Aggregate Cap, Net Excess Generation	▸ In July 2015, the Senate passed a bill that raises the net metering aggregate cap to 1,600 MW and eliminates the cap altogether once 1,600 MW of capacity is reached. This bill also permits the DPU to adjust the distribution portion of the net metering credit for systems consuming less than 67% of their generation onsite beginning in 2017.
8.	Minnesota	Net Metering Rules, REC Ownership, Net Excess Generation	▸ The Minnesota Public Utilities Commission (PUC) issued proposed rules to revise the state's net metering policy in December 2014 pursuant to H.F. 729 of 2013. The final rules were adopted in September 2015. The rules specify that a net-metered facility may elect kWh credits for monthly net excess generation in place of a payment at the avoided cost rate. The proposal also clarifies the definition of a standby charge and that generators own all RECs unless other ownership is expressly stated.
9.	Mississippi	Net Metering Rules, Aggregate Cap, System Size Limits, treatment to Net Excess Generation	▸ In April 2015, the Mississippi Public Service Commission (PSC) issued proposed net metering rules. The proposed rule requires all electric distribution companies (EDCs) to offer net metering. The aggregate cap is 3% of each EDC's current total distribution system peak demand, with a 10 kW system size limit for residential customers and a 2 MW system size limit for non-residential customers. Net excess generation during a billing period would be rolled over to the following billing period in the form of a kWh credit. At the end of the annualized period, an EDC compensates the customer for any net excess generation credits at the avoided cost of wholesale power rate.
10.	New York	Net Excess Generation	▸ In September 2015, several stakeholders petitioned the New York State Public Service Commission to change the current way the true-up date for net excess generation credits is assigned to residential net-metered PV customers. Net-metered customers currently have a **one-time option to select the date when their excess credits are cashed out each year at the wholesale rate.**
		Aggregate Cap	▸ In July 2015, the Orange and Rockland Utilities (O&R) informed the New York State Public Service Commission (PSC) that based on applications received, it had exceeded its net metering cap set at 6% of 2005 peak load (62 MW). O&R has proposed the PSC to treat applications beyond 6% cap as a **buy-all, sell-all arrangement, where the customers pay for all electricity delivered to them at normal rates, and their exported electricity will be credited at the avoided cost rate.** O&R will continue

Sr. No.	State	Type of change	Description
			to accept net metering applications but will notify customers that the new requests will be treated differently, as determined in the future by the PSC.
		Meter Aggregation	▸ In April 2015, the New York State Public Service Commission issued a transition plan to change remote net metering from monetary to volumetric crediting. Previous rate design allowed a farm or a non-residential customer with remote net metering at a site where a non-demand rate was in effect to obtain monetary credits that could be applied to its satellite sites. On-site net metering credits are offered volumetric rates which were generally lower than monetary rates that are offered for remote net metering. This potentially offered an advantage for remote net metering customers and created an opportunity for arbitrage by pursuing remote instead of on-site net metering.
11.	Pennsylvania	System Size, Net Excess Generation	▸ In April 2015, the Pennsylvania Public Utilities Commission (PUC) proposed changing net metering system size cap from 110% to 200% of load for on-site generation. The PUC ended public comment on the rules at the end of May. The draft is subject to 18 months of reviews by state lawmakers and regulators before it is finalized by September 2016. ▸ The interconnections levels are defined as below ▸ Level 1: is used for invertor based small generator capacity for systems with capacity of 10 KW and less. ▸ Level 2: For interconnection of systems 5 MW or less.
12.	South Carolina	South Carolina	▸ In August 2015, the South Carolina Public Utilities Commission approved new net energy metering riders for Duke Carolinas, Duke Energy Progress, and South Carolina Electric and Gas. Pursuant to a previous settlement agreement, all tariffs will allow customers to net meter at the full retail rate.
13.	Virginia	Net Metering Rules, System Size	▸ In June 2015, the Virginia State Corporation Commission (SCC) opened a proceeding to amend the net-metering rules pursuant to a law passed in 2015 session that, among other changes, (1**) increases system size eligible for net metering for non-residential customers from 500 kW to 1 MW**, (2) limits the capacity of a generation facility to the expected annual energy consumption, and (3) clarifies requirements regarding a participant's obligation to bear the cost of equipment required for interconnection. The SCC published its

Sr. No.	State	Type of change	Description
			proposed rules and is reviewing public comments. ▶ The system limit capacity for Virginia is increased to 20 kW for residential, 1 MW for non-residential and 500 kW for agricultural.

Demand on increased fixed charges.

The trend of utilities proposing fixed charge increases for all residential customers continued in Q3 2017. These fixed charge increases (which are sometimes accompanied by a corresponding decrease in per-kilowatt-hour (kWh) rates) impact the financial value of solar to residents by limiting the portion of their electric bill that can be reduced through self-generation and reducing the value of any net metering credits that residential solar systems generate. Furthermore, rate structures that increase fixed charges and decrease variable energy charges have the effect of decreasing utility bills for large energy consumers while increasing utility bills for customers who consume less energy (including distributed solar owners).

Demand on increased Solar and distributed generation charge

Several utilities in U.S. have proposed extra charges only to solar or distributed generation customers. In 2015, state regulators approved and were considering solar or DG charge increase for 19 utilities in 12 states of U.S. The structure of proposed charges vary significantly, including flat monthly charges, charges based on the capacity of the installed solar system, charges based on measured monthly peak generation, and increases to variable per-kWh charges that would apply only to net metering.

5.2.3 Development of new business models

Community Solar

"Community Solar" refers to a program wherein multiple community members, individuals voluntarily come forward and own GRPV systems and provide power to the consumers. While some of the community solar projects could be large in size and can also be small scale solar project like distributed generation. This will enhance the participation of residential consumers as solar system will be community focussed.

Community solar programs are expanding into new states and utility service areas, yet this option is not yet available to most U.S. residential customers. Community solar has sparked strong interest among many electric utilities. In 2017, there were 24 states considered or enacted changes to net metering policies[27] and 13 states took policy action on community solar.

These utility programs range significantly in design and size. For example, Xcel Energy's community solar program in Colorado, stemming from Colorado's landmark 2010 community solar legislation, was capped at 30 megawatts annually, whereas Xcel Energy's community solar program in Minnesota does not have an aggregate cap, but limits the size of each community solar garden to 5 megawatts.[28]

Few of the policy directives in different provinces in USA have been appended below:

Table 16: Policy directives in different provinces of USA

Sr. No.	State	Policy Directives
1.	Hawaii	In 2015, any person or entity was allowed to "own or operate an eligible community-based renewable energy project." The bill requires utilities to file community renewable energy tariffs with the Hawaii Public Utilities Commission (PUC) by October 1, 2015.

[27] *50 states of solar – A quarterly update on US distributed generation policies*

[28] *50 states of solar – A quarterly update on US distributed generation policies*

		Hawaii Electric Company (HECO) proposed a community solar pilot program that was rejected in Q3 on the grounds that the PUC had not yet instituted the community-based renewable energy tariff.
2.	Minnesota	In August 2015, the Minnesota Public Utilities Commission approved a settlement agreement between Xcel Energy and a group of solar developers, placing an initial 5-MW cap on co-location for existing solar-garden applications. For applications submitted from September 25, 2015, through September 15, 2016, community solar gardens will be limited to 1 MW at a given site. Further rules on interconnecting solar gardens were also specified, including a requirement that Xcel approve interconnection within 50 days of an application being deemed complete
3.	New York	In July 2015, the New York State Public Service Commission issued an order that established community net metering in the state. Implementation of the program was divided into two steps. The first step of the program began on October 19, 2015 and will last until April 30, 2016. During this period, the projects were limited to siting distributed generation in areas where it provides the greatest locational benefits to the larger grid and in areas that promote low-income customer participation. The second phase began in May 2016, when the community net metering projects had been fully implemented throughout utility service territories.
4.	Oregon	The Public Utility Commission of Oregon (PUC) opened a docket in order to recommend a community solar program design to the legislature by November 1, 2015. The PUC requested proposals for program designs by August, held two workshops, and also hold public meeting.

Third party ownership

Earlier to 2015, Third party model was not allowed. Third-party solar ownership laws were acting as a financing barrier for distributed solar. Florida, Kentucky, North Carolina, Oklahoma, and South Carolina did not allow third-party solar PPAs.

While no additional third-party ownership till 2015, there are pending decisions in Delaware, North Carolina, and New Hampshire to clarify the regulatory treatment of third-party entities seeking to offer solar PPAs. In Florida, an ongoing ballot initiative would create a constitutional amendment legalizing third-party PPAs.

Utility-led grid connected solar rooftop

Utility-led residential grid connected solar rooftop programs are showing emerging trend in USA. In these programs, utility-owned solar systems are installed on customer roofs. These programs provide an opportunity for utilities to participate directly in the distributed solar market, though they have been met with controversy in some states.

The financial value to customers varies widely across programs. In Arizona, for example, Tucson Electric Power offers to convert the electric accounts of solar customers to a fixed charge account, where customers pay a flat monthly fee based on their existing energy consumption. The monthly fee will be fixed for 25 years, insulating the customer against future rate increases. In Georgia, conversely, the state’s largest utility has begun selling customer-sited solar systems through its unregulated business arm, offering a customer value very similar to that of third-party ownership options.

5.2.4 Energy accounting and Commercial settlement

In USA different state has followed different methods for energy accounting and commercial settlement. In Hawaii, Hawaii Public Utilities Commission eliminated the retail rate remuneration for new net metering customers. The new scheme replaces old net metering regulation and leaves PV system owners to choose between a grid-supply option and a self-supply option:

- The grid-supply option: customers receive a fixed credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid.

- The self-supply option is primarily aimed at creating solar owners who do not export generation to the grid, though the commission stressed no non-export design should prevent solar systems from providing grid support. All power produced by the customer's system will need to be used or stored on-site

5.2.5 Technical aspects

As is the case in Europe, the USA has implemented specific regulation concerning the connection to the low voltage grid. The market access requirements for PV equipment are segmented in two main areas - safety and performance - that are integral to each other in the overall construction. The focus of the UL standards (UL, 2011) is in providing requirements for materials, construction and the evaluation of the potential electrical shock and fire safety hazards. The focus of the IEC requirements is in terms and symbols, testing, design qualification and type approval.

UL certifies that PV equipment complies with the safety, environmental and other performance requirements of the appropriate standards. UL supports manufacturers with the compliance to both the UL and the IEC requirements utilizing a combined project or if needed, as individual evaluations. The only norms that contain information towards grid connection are UL 1741 and IEEE 1547.

5.2.6 Key Takeaways

The key take away from USA of are summarised below:

- The tariff re-design to reflect DISCOMs fixed cost recovery is required to protect DISCOMs interest and reduce possible burden on non-solar consumers.
- New business models needs to be introduced for different consumers to accelerate GRPV deployment
- Capacity limits can be relaxed after gaining experience in terms of technical aspects and suitable commercial settlement

5.3 Experiences of European Union (EU) GRPV market

5.3.1 European Union

EU has become world leader in solar in terms of installed capacity with 100 GW in 2016 of solar PV from 3 GW in 2006. The European solar market started in 2008 and gradually expanded till 2011 due to policy support and declining costs. After 2011, due to damaging retroactive changes to support schemes, stop-start subsidies and other factors, the EU solar market went into decline and volumes of new solar installations reached a five year low in 2014 at 7.1GW. In 2015 the European PV market started growing with a 15% year on year increase to 8.2GW, of which 7.7GW was in the European Union[29].

Different options for GRPV projects in EU

Wide consumer coverage, different business model to cater consumer's demand and multiple financing schemes helped in scaling up GRPV penetration across EU. Consumer categories covered and different options available for consumer; business models and financing schemes are provided below:

Application segment

- ✓ Single family residential
- ✓ Multifamily residential
- ✓ Commercial buildings, shopping centres and office buildings
- ✓ Public and educational Buildings
- ✓ Industrial buildings
- ✓ Solar farms

Business models

- ✓ Self-consumption
- ✓ Power Purchase Agreements
- ✓ Cooperatives
- ✓ Virtual Power Plants

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Financing Schemes

- ✓ Self-funding
- ✓ Debt
- ✓ Equity
- ✓ Mezzanine financing
- ✓ Leasing
- ✓ Crowd funding
- ✓ Combo financing

Application segments for PV

The application segment for PV across Europe are provided below:

Table 17: Application segment for PV

Sr. No	Single family residential house (owned or rented)	Multi-family residential buildings (owned or rented)	Shopping centres, office buildings and other commercial buildings	Public and educational buildings	Solar Farms
1.	This model can be of two types either owner owned homes or rented homes	40% of the population of the European Union lives in multi-family residential buildings	Buildings that have one single occupant and those that have multiple occupants	Long-time horizons	Simpler from a legal perspective.
2.	Less Risk	Higher Self consumption	High electricity Demand	Low costs of capital	Rights issues are quite simpler
3.	Savings on Electricity Bills	Long term contract involved	High Consumption	More stringent energy performance standards	Standardised Contracts
4.	Widely supported by Governments.	Examples include social housing	More area	Creating more scope for solar PV	Permission required from Municipality

Key drivers for GRPV segment in EU

The profitability drivers for successful implementation of solar in EU are provided in the figure below:

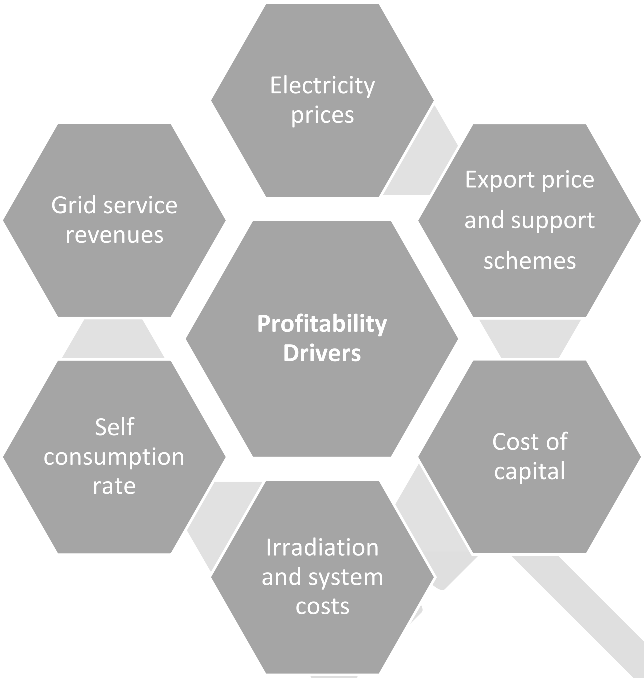

Figure 9 : Key drivers for GRPV segment in EU

As the retail and wholesale prices are on a high end which has made electricity prices as one of the main driver for building a solar PV. The schemes of the government to support the solar PV has made solar PV a successful model in EU. The cost of capital plays a major role in determining the feasibility of the project. The solar irradiation, or level of sunlight, makes a significant difference to the output and therefore rate of return of a solar PV system. The grid service revenue associated with the export and import credit facility the grid connected solar rooftop model has become a promising model in many countries.

A major barrier to building mounted commercial solar PPAs across the EU is the perceived risk that the power consumer in the building could change or cease to exist. Other risks are associated with quality, political, curtailment, and legal etc. Solutions to remove barriers are provided below:

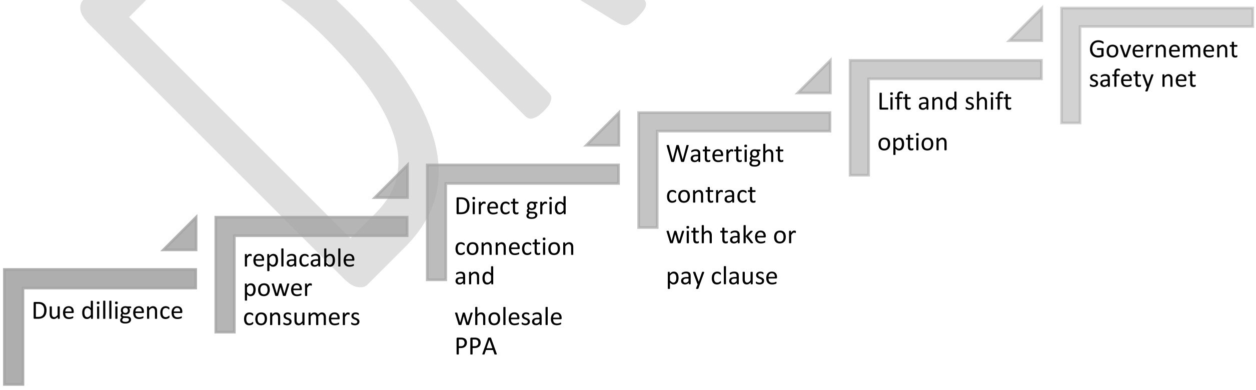

Figure 10 : Possible steps to overcome off taker risks

Financing schemes around EU

There are a number of different financing schemes that can be used to raise money for solar PV. The main categories are self-funding, debt, equity, mezzanine financing, leasing and crowd funding. These different financing schemes can be combined in various ways. Further, a project can be re-financed several times during an installation's lifetime and therefore, different financing schemes will be appropriate at different stages of a project, as shown in the figure below:.

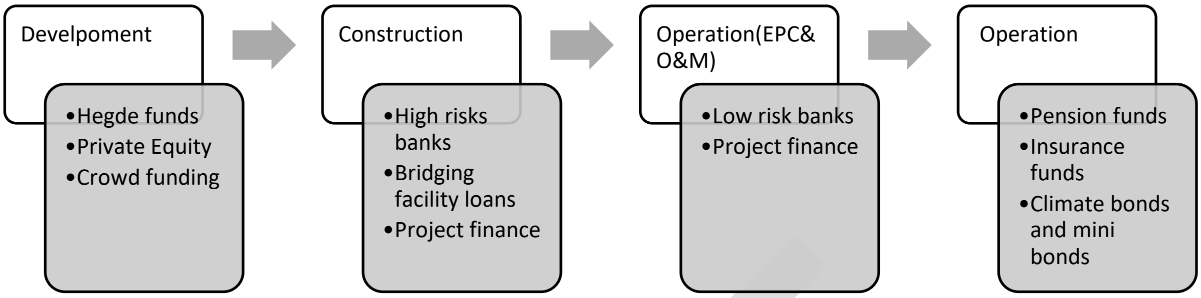

Figure 11: Stages of utility-scale ground mount solar PV and corresponding sources of financing

1) Self-funding

Self-funding is the simplest financing scheme in which the power consumer owns GRPV system. This has been the most common financing scheme in the small residential and commercial consumers. In last ten years, development in solar PV in Europe has been driven by two key drivers; self-funding and government support schemes.

However, as self-funding limits solar projects to sites and owners who have large amounts of cash readily available it cannot be 'fit for all' kind of model. Different funding options needs to made available suitable to every stakeholder.

2) Debt

Debt financing comes in many different forms as shown in the figure below:

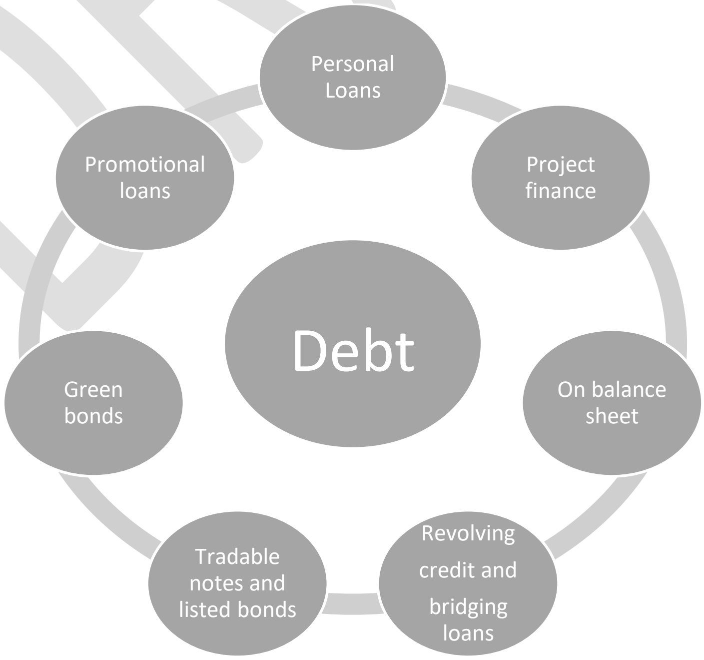

Figure 12 : Debt financing

Like conventional projects, GRPV systems are also financed by a combination of debt and equity.

Personal loans are readily available for solar in EU. The term of the loan depends upon the creditworthiness of the owner and the details of the PV project. Project finance is debt financing where the cash flow generated by the project, usually held within a Special Purpose Vehicle, is used to repay the loan. Project finance is generally used for large-scale infrastructure investments.

The revolving credit facility is where a bank or investor lends to a specific company on the basis of its relationship with that company to do a specific technology, and where the borrower can draw down, repay and withdraw funds. Tradable notes and listed bonds are debt instruments which in many ways resemble project finance loans but can be bought and sold on a secondary market and can be split between several providers of finance.

3) Equity

A project can also be financed through equity where an investor gains part or whole ownership of the asset. It is riskier form of investment in comparison to debt financing as it requires a high rate of return. The following are the different types of equity investment used in EU.

A) Mezzanine financing

Mezzanine financing is like the hybrid between the debt and equity. It can take the form of unsecured debt or preferred shares. It is more expensive than regular debt financing, but cheaper than equity so can be used to minimize the equity share and therefore, the overall cost of capital.

B) Leasing

Leasing is an innovative and promising financing scheme for solar PV. Here the solar leasing company designs, purchases and installs a PV system on a consumer’s roof and receives a monthly rent payment or leasing fee over a long period of time (10-20 years).

C) Crowd funding

Crowd funding is a very promising solar financing scheme where a large number of people each put in small amounts of money into a scheme in order to raise money for a PV project. The crowd funding can be divided into debt, equity and grants. Crowd funding is combined with bank loans or equity and can help communicate a project to the local community, especially when local acceptance is required.

There are also substantial tax benefits to crowd funded finance. It is also sometimes used when a project might struggle to get other forms of financing, especially for innovative and small-scale projects. Crowd funding platforms might have different due diligence processes as compared to banks.

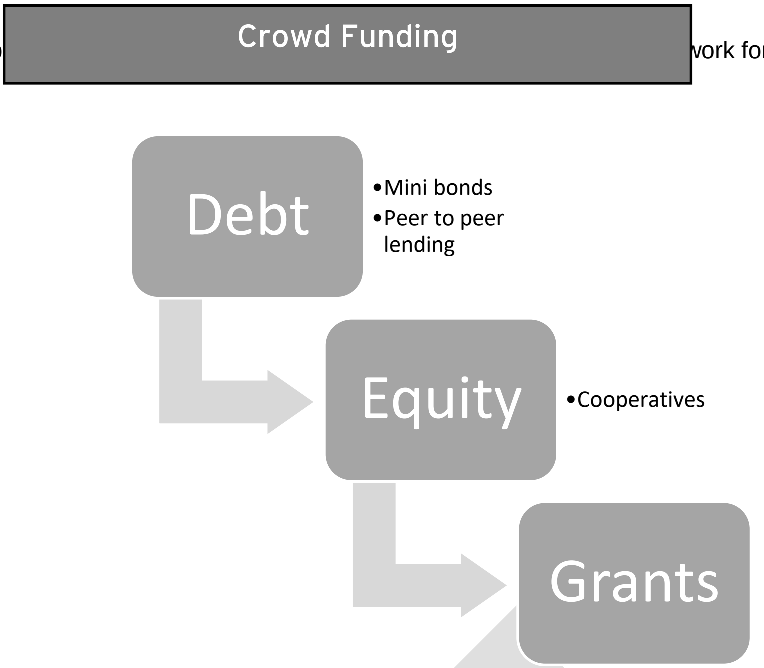

Figure 13 : Crowd Funding

Prevalent Business models in EU

Out of many, primarily two business models are very popular in EU, which are self-consumption and supply contract business model.

1) Self-Consumption business model

In self-consumption business model Investor, Operator and Power Consumer are the same entity. The Power Consumer contracts with an Engineering, Procurement and Construction (EPC) firm to build the system. If the system is self-funded there is no need to contract with a finance provider but if the system is being financed by debt, equity or one of the other financing schemes then a contract needs to be signed and the capital repaid. Excess electricity is sold to the grid for a price (often referred to as the feed-in tariff or export tariff). The Power Consumer then gets its residual electricity from an electricity provider and contracts with an Operations and Maintenance (O&M) provider for maintenance, if necessary.

2) Power Purchase Agreements (PPAS) Supply Contract Business model

PV is an ideal technology for long-term fixed price contracts as most of the costs of a system are upfront costs at the beginning of the project. Where PPAs track the electricity price, there is a risk to the investors of a sudden decrease in electricity prices, but this can be mitigated with floor and roof prices. Some PPA contracts also include a buyout clause where the power consumer can buy the system outright after a period of time, usually 5-8 years, and switch to a self-consumption business model without having had to pay out the full amount at the beginning of the project.

Energy Accounting and settlement

In Denmark, premium tariff system promotes the generation of electricity from renewable sources based on bonus payments. The operators of renewable energy plants usually receive a variable bonus, which is paid on top of the market price. The sum of the market price and the bonus shall not exceed a statutory maximum per kWh, which depends on the source of energy used and the date of connection of a given plant. FiT for the excess electricity guaranteed during 20 years, with a decreasing value after 10 years.

The new "net metering" scheme allows electricity producers using all or part of the electricity produced for their own needs to be totally or partly exempt from paying Public Service Obligation on this electricity. The Public Service Obligation is a charge levied to support renewable energy. The net metering system has now a cap of 800 MW (+20 MW for municipal buildings) until 2020.

In Italy they introduced electricity rate reform that is to be implemented until 2019. At the core of the reform is the phase-out of the electricity tariff scheme where tariffs increased progressively with the energy demand. The Italian regulator AEEG wants every residential customer to pay the same grid and system surcharges, independently from the electricity consumption.

5.3.2 Key Takeaways

Innovation in financing mechanisms and business models are only possible when the basic regulatory framework allows for new entrants and ways of doing things. If the regulatory framework is overly restrictive, new models that can facilitate the up-front investment required cannot come forward. It is critical that electricity markets rules are opened up across to allow for more decentralised electricity generation and supply.

5.4 Germany

Germany has made significant contribution in the field of renewable and especially in photovoltaic industry. Feed in tariff concept was introduced in Germany in 1991 but the electricity reforms in the year 2000, initiated the photovoltaic energy in the electricity system.

5.4.1 Regulatory interventions

The policies and regulations went through various modifications since inception. The policy evolved facing many challenges and difficulties. The 2000 policy guaranteed PV installation access to the grid with increase in numeration from 8 cents/kwh to 51 cents/kwh. This expanded the photovoltaic industry and improved the financial feasibility of photovoltaic installations. Key grid connected solar rooftop policy interventions which supported the market to proliferate are highlighted below:

Table 18: Key policy directives Germany

Serial No	Areas	Key policy directives
1.	Grid interconnection	The Renewable Resources Act provides guidelines for interconnection, and mandates the connection of renewable systems on priority basis. VDE 4105 Code of Practice is mandatory from January 2012 for interconnection with the low-voltage grid
2.	Financial incentive structures	Feed in Tariff - periodically updated to promote energy export to the grid
3.	Sustainable business models	• Long-term FiT guarantee • Soft financing • Streamlined interconnection and administrative approval processes
4.	Metering arrangements	Gross metering to encourage solar project development, independent of captive loads of consumers

In 2004, feed in tariff reforms established key characteristics which made German incentive policy successful. Under this reform sub categories for photovoltaic installations were made and different remuneration based on capacity installed was calculated. The reform also set an automatic annual 5% regression mechanism for remuneration which attracted investment. In addition, remuneration for photovoltaic installations was increased as compared to 2000, which meant that the feed-in tariff was economically viable. Following table highlights key remuneration figures in early days of feed-in-tariff policy for different applications.

Table 19: System capacity range

Sr. No.	Particulars	Installations on buildings and sound barriers			Installation in open areas
1.	System capacity ranges	up to 30 kWp	from 30 kWp	from 100 kWp	No limit
2.	Remuneration for systems in 2004	57,40 cents/kWh	54,6 cents/kWh	54,0 cents/kWh	45,7 cents/kWh

In 2009 the government implemented different reforms which focussed on adapting and adding new characteristics to the system. The remuneration levels were reduced in response to the growing number of PV installations. This happened again between 2010 and 2012 because of the unexpected acceleration of PV diffusion. Additionally, the annual regression mechanism was increased to between 8% and 10%, with a special clause that allows for acceleration or deceleration of the regression depending if the annual capacity installed surpasses a defined threshold.

The government also introduced auto consumption for photovoltaic system. The feed-in tariff for electricity injected into the grid was higher than the electricity price, therefore the reform introduced an additional remuneration for electricity that is auto consumed. The consumers could save buying less electricity from the grid and receiving an additional remuneration. This marked an important shift towards incentivizing auto consumption.

Since 2012 the remuneration rate is decided based on a monthly basis by a formula decided by the law considering the capacities installed in the previous years. The government also targeted to achieve at least 2.5 and 3.5 GW of installed capacity each year. Self-consumption was a viable model for co-financing photovoltaic systems, because the remuneration for injecting electricity into the grid was lower than the electricity price. The reform also made self-consumption exempt from paying volumetric taxes (such as grid fees, renewable energy tax etc.).

An alternative model of feed in premium was introduced which helped the operator of PV to sell the energy on short term market. This model helped in gaining a part of remuneration along with the premium from selling of electricity in the market.

In 2014, incentive policies for photovoltaic energy went through another transformation. A key change was made to the feed-in premium model. The government established that the feed-in premium model will be on systems bigger than 100kWp. Consumers with photovoltaic systems bigger than 100kWp have to find a retail energy sales company, which assumes the role of selling their electricity. The classic feed-in tariff continued to be implemented for smaller installations.

During the same year, the German government introduced a tax on auto consumption. This meant that starting in 2014, consumers would pay 30% of the renewable energy tax, and 40% starting in 2017. This rule was only applicable to systems with a capacity above 10kWp.

A snapshot of feed-in-tariff evolution in Germany has been highlighted below:[30]

Table 20: FiT evolution in Germany

Sr. No.	Parameters	2000	2004	2009	2012	2014
1.	Capacity Categories	No categories	<30 kWp; 30-100 kWp; > 100kWp;	<30 kWp; 30-100 kWp; > 100-1000kWp; > 1000kWp;	<30 kWp; 30-100 kWp; > 100-1000kWp; > 1000kWp;	<40 kWp; 40-100 kWp; > 100-1MWp; 1-10MWp; <10MWp*
2.	Metering principle	Gross metering	Gross metering	Gross metering	Gross metering	Gross metering
3.	Remuneration model	Feed-in tariff	Feed-in tariff	Feed-in tariff; Feed-in premium; auto consumption premium	Feed-in tariff; Feed in premium	Feed-in tariff; Feed in premium
4.	Time frame	20 years	20 years	20 years	20 years	20 years

[30] Photovoltaic energy diffusion through net-metering and feed- in tariff policies: Learning from Germany, California, Japan and Brazil

5.	Business models	Injection into grid	Injection into grid	Injection into grid; self consumption	Injection into grid; self consumption	Injection into grid; self consumption
6.	Remuneration rate	57 cents/kWh	57,40 cents/kWh; 54,6 cents/kWh; 54 cents/kWh; 45,7 cents/kWh	43,01 cents/kWh; 40,91 cents/kWh; 39,58 cents/kWh; 33 cents/kWh; 31,94 cents/kWh	28,74 cents/kWh; 27,33 cents/kWh; 25,86 cents/kWh; 21,56 cents/kWh; 21,11 cents/kWh	13,15 cents/kWh; 12,80 cents/kWh; 11,49 cents/kWh; 9,23 cents/kWh; 9,23 cents/kWh
7.	Regression rate	None	5% annually	Flexible 8-10% annually, depending on annual installed capacity	Monthly determined regression depending on growth of capacity	

Interconnection standards

Large penetration of GRPV systems may create technical issues such as reverse power flow, reactive power compensation, over voltage or under voltage depending upon the length of network and supply demand situation. Germany, where the largest GRPV system has been deployed, has formulated stringent grid interconnection guidelines and laws to maintain grid stability and standardize power qualities from distributed generation resources. Mainly, there are three major directives in Germany that mandates GRPV plants to meet technical standards for their interconnection with the grid:

- The BDEW medium voltage directive
- The VDE code of practice
- The Renewable Energy Sources Act (EEG) 2012

The BDEW medium voltage directive:

Since January 1, 2009, the revised medium voltage directive has been in effect for all distributed power generation plants that feed at the medium voltage level into the power distribution grid – i.e., typically for plants with approximately 200 kW of power and more. The revised version was formulated by the German Association of Energy and Water Industries (BDEW). However, the network technology / network operation forum (FNN) – a committee of the Verband der Elektrotechnik (VDE) created in 2008 was responsible for the final version. Its requirements may be divided into four stages, which successively came into effect.

- **Participation in feed-in arrangement**

If a section of the relevant medium-voltage grid or higher level transmission grid is temporarily overloaded, the distribution grid operator should be able to remotely limit the power of decentralized power generation plants, gradually, like, in increments of no more than 10 percent of normal power. To do so, the operator sends a ripple control signal which must be implemented as limitation of the fed-in active power (typically 60, 30 or zero percent of the rated power). The respectively required limitation must be implemented by the inverter within 60 seconds.

- **Active power reduction in case of over frequency**

In Europe, the frequency in alternating current grids has to be kept constant at exactly 50 Hz or within strict limits of 47.5 to 50.2 Hz. If more energy is taken from the grid than is fed in by the generators, the frequency will drop – it will rise in case of an energy surplus. Earlier the PV inverters had to be disconnected from the grid immediately after the power frequency goes beyond he permitted range of. However the sudden disconnection of large PV power generation capacities can have a negative effect on the grid stability. Therefore, the requirement of frequency-dependent power regulation in the inverter was felt in Germany. The investor should reduce their current power with a gradient of 40 percent per Hertz from 50.2 through 51.5 Hz and only disconnect from the grid above 51.5 Hz. The disconnection limit in case of under frequency remains unchanged at 47.5 Hz.

- **Provision of reactive power**

The voltage must be kept within defined limits on all grid levels. However, voltage increases may occur due to the increasing (active power) fed in the distribution network, which make the connection of additional power generation plants more difficult. Furthermore, existing phase shifts and/or reactive power percentages in the grid reduce its transmission capacity and result in increasing the transmission losses. The typical causes of phase shifts are transformers, large motors, or longer cable routes. Inverters with reactive power controlling capability can help to compensate the reactive power balance in the grid or keep the voltage stable at the grid connection point in order to ensure the voltage quality stipulated in Voltage disturbances standard EN 50160. Consequently, the medium-voltage directive requires power generation plants to be able to supply or absorb both active and reactive power (leading or lagging phase shift). The grid operator may demand a displacement power factor between 0.95 and 1 with three variations for the definition of the target value being available to that end:

1. The grid operator specifies fixed target values that the plant operator is required to set.
2. Various reactive power values are set on the basis of an agreed upon time schedule or specified via supervisory control signal by a central control centre of the grid operator.
3. The reactive power percentage is regulated via a characteristic curve – depending on the grid voltage measured at the connection point or the ratio of the currently supplied active power and the nominal power of the inverter. The latter variation is frequently used when the PV plant strongly influences the voltage at the connection point. In that context, the voltage is supported at low output power levels while it is reduced at high output power levels in order to relieve the connection point. The grid operator provides the respective characteristic curve.

- **Dynamic grid support**

Local power generation plants had to disconnect from the grid immediately, even in case of brief drops in the grid voltage. However, this becomes problematic when significant power generation capacity is added, as smaller system interruptions could result in the sudden disconnection of larger power generation capacities under certain circumstances, resulting in grid imbalance. The revised medium-voltage directive now requires PV inverters to support the grid in case of an incident by "riding through"[31] voltage drops of up to several seconds and then resuming normal feed-in immediately afterwards (so-called low-voltage ride-through, or LVRT). The inverter behaves passively throughout the course of the error in the limited version. The device also needs to feed reactive power into the power distribution grid during a voltage drop in the complete version of the LVRT, as it has been required since April 1, 2011. As a result, they contribute to the resolution of the incident and help to trigger the grid protection devices.

The VDE code of practice:

The VDE 4105 code of practice has been in place since August 1, 2011, and binding since January 1, 2012, and affects all GRPV plants that feed in to the low-voltage grid, which means the vast majority of them.

- **Basic requirements**

[31] In electrical power engineering, fault ride through (FRT), sometimes under-voltage ride through (UVRT) or Low voltage ride through (LVRT) , is the capability of electric generators to stay connected in short periods of lower electric network voltage

The following is a list of the basic requirements with which each inverter and each GRPV plant are required to comply:

Table 21: Basic requirement of GRPV plants

Sr. No.	Compliance parameter	Description
1.	Active power reduction in case of over frequency	Though the directive has no impact on planning a GRPV plant it is extremely important for grid safety. In earlier situations, GRPV plants had to disconnect from the grid instantly when the power frequency was too high. However, the simultaneous disconnection of the large number of installed PV power at load end now imposed threat to grid stability. Therefore PV plants are not disconnected immediately when the power frequency is too high, but is reduced gradually. The permissible frequency band will be then expanded to a range from 47.5 to 51.5 Hz. The current feed-in power must be reduced by 40 percent/Hz. The plant will be disconnected only if 51.5 Hz is attained. According to this characteristic curve, the curtailing percentage is always based on the current power when the 50.2 Hz mark is exceeded. If the irradiation conditions improve in the meantime, the inverter may only increase its power with a defined slope to the new, non-throttled maximum value upon dropping below the curtailing limit. The increase in power may take several minutes.
2.	Connection criteria and permissible unbalanced load	The connection criteria have become clearer as far as the maximum unbalanced load is concerned: a general limit of 4.6 kVA per phase applies and the previous option of feeding in up to 110 percent of this power as a single phase has been dropped. Hence, a maximum plant power of 13.8 kVA results when using single-phase, uncoupled inverters (3 x 4.6 kVA) only. Therefore, at least the proportion of the power exceeding 13.8 kVA must be designed with three-phase or communicatively coupled single phase inverters in larger plants. Conversely, larger three-phase plants may also be supplemented with single-phase and non-coupled devices as long as their aggregate power of 4.6 kVA per phase is not exceeded.
3.	Grid and GRPV plant protection	An additional new requirement concerns grid and plant protection (short: G/P protection), i.e., the protective device that monitors all relevant grid parameters and disconnects the plant from the grid, if necessary. A freely accessible disconnection point for plants with more than 30 kVA of apparent power is no longer required, but more extensive grid monitoring including the power frequency and single error safety is stipulated in return. Plants with less than 30 kVA of apparent power may still be operated with G/P protection integrated in the inverter. The higher requirements that apply here, including the fail-safe protected switch device, have already been met by SMA inverters for a long time. If all inverters include separate stand-alone grid detection with grid disconnection via the tie breaker integrated in the device, separate stand-alone grid detection may be omitted in the central G/P protection. This solution is

Sr. No.	Compliance parameter	Description
		a considerable cost-saver and is possible with all SMA inverters. **Set values for the G/P protection:** ▸ Deactivation limits: Voltage drop protection (U < 184 V ▸ Voltage increase protection (U >) > 253 V ▸ Voltage increase protection (U >>) > 264.5 V Frequency drop protection (f < 47.5 Hz ▸ Frequency increase protection (f >) > 51.5 Hz Reconnection limits: Voltage greater than 195.5 V and less than 253 V Frequency greater than 47.5 Hz and less than 50.05 Hz

- **Supplementary requirements**

The following requirements of the code of practice are only valid for a certain power plants. The three phase feed-in connection criteria and specifications are considered a special situation in this case.

Table 22: Code of practice for plants

Sr. No.	Compliance parameter	Description
1.	Provision of reactive power	More GRPV plants can utilize the existing infrastructure of the low-voltage grid by means of inverters with reactive power capability; as a result, the supply of reactive power is also now required on this voltage level. The feed-in of active power into the low-voltage grid with its predominantly ohmic properties generally results in an increase of the voltage at the feed-in point. In the case of long network feeder, an additional aspect is that the voltage must already be set higher on the transformer side in order to ensure that the lower voltage threshold of 207 V is still maintained at the consumer. If active power is to be fed in on the side of the consumer now without absorbing power of a similar magnitude at the same time, the upper voltage limit may be exceeded at the feed-in point. However, inverters may lower the voltage at the grid connection point by simultaneously consuming lagging reactive power. Consequently, the code of practice requires the capability of the inverters to feed in with displacement power factors up to 0.95lagging/leading from an apparent plant power of 3.68 kVA If the plant power exceeds 13.8 kVA, even displacement power factors up to 0.9 must be supported.
2.	Three-phase feed-in	The code of practice aims to achieve the goal of actively balancing the voltage in the low-voltage grid by having larger plants feed into the grid as symmetrically as possible. However, there are not any special regulations for plants exceeding 13.8 kVA; the unbalanced load of 4.6 kVA per phase applies independent of the power, even in case of an error. Yet the unbalanced load limit means that at least a portion of the plant power exceeding the 13.8 kVA needs to feed in using three-phase voltage. In addition to deploying three-phase inverters, there is also another solution in the communication-based coupling of single-phase inverters into three-phase feed in units, such as the ones SMA offers with its Power Balancer for the Sunny Mini Central production series. With this option, if one device fails, the

Sr. No.	Compliance parameter	Description
		other devices are also disconnected so that no significant unbalanced load can occur
3.	Remote power limitation	The distribution grid operator should also be able to remotely limit the power of PV plants in increments of no more than 10 percent of nominal power in the low-voltage grid (in that context, proven increments are 60, 30, or zero percent of the nominal power). Among others, conceivable reasons for a power limitation include the operation of emergency generating units, a short term overload of the superordinate medium-voltage or transmission grid, or a system endangering frequency increase. This requirement of the code of practice applies to all plants with more than 100 kW of power and is otherwise comparable to that in the medium voltage directive.

The Renewable Energy Sources Act (EEG) 2012:

The Renewable Energy Sources Act has laid down the requirements in terms of grid integration since 2009. The version passed on January 1, 2012, greatly expands on these requirements looking at the increased penetration of the distributed renewable sources.

The Renewable Energy Sources Act (EEG) as amended mid-2011 and valid from the beginning of 2012 included new requirements regarding the grid integration of PV plants. It stipulated that plants with more than 100 kW peak power must participate in feed-in management and, at the same time, extends this demand to smaller plants – of course in less stringent form Furthermore, operators of PV plants with less than 30 kWp of power were allowed to skip installing the device for remote power limitation if they agree to accept limitation of feed-in power to 70 percent of the installed generator power. As for the obligation to retrofit, both power categories also differ: plants between 30 and 100 kWp were to be retrofitted by the end of 2013, if they were commissioned after December 31, 2008. There was no obligation to retrofit plants with less than 30 kWp.

Table 23: Compliance parameters

Sr. No.	Compliance parameter	Description
1.	Retrofitting older PV plants	The retrofitting of older PV plants was not a problem. The appropriate technology was available for plant and distribution grid operators for plants with more than 100 kWp. Further, PV plants between 30 and 100 kWp could also be retrofitted in accordance with the FNN recommendation.
2.	Design according to the 70 percent option	The application of the 70 percent option is only advantageous if the maximum expected feed-in capacity on the grid-connection point is substantially less than the generator nominal power. E.g. shading of the modules, substantial self-consumption at the same time as the generation maximum or east/west-facing PV arrays because the maximum power of the substrings will never occur simultaneously.

5.4.2 Key Takeaway

Based on the German Experience, especially. In terms of interconnection and safety of grid operations the key learnings are summarised below:

- Visibility and control over solar generation beyond certain capacity is must to the DISCOM or system operator in view of requirement of stable grid operation. For low capacity systems certain restrictions should be put so that minimum level of feed-in is maintained

- The GRPV invertor system must be able to respond to the system requirement and follow instruction of the area system operator and their technical specifications needs to be designed accordingly
- Going forward, stringent interconnection standards will be required when more and more GRPV systems will get added in distribution network.

5.5 Key features of Canada – Ontario NEM regulations

5.5.1 Evolution of regulatory framework

The net metering regulation in Ontario was initiated in 2005. The regulation mandated that distributors would offer net metering to customers. In 2009 FiT (Feed In tariff) was launched to encourage the development of Renewable, attract investments and promote clean energy use in the country. FiT helped Ontario in achieving its clean energy targets by improving the air quality and eliminating the dependence on fossil fuels, and coal fired generation. An independent Electricity System operator implements the changes for micro FiT and FiT programs. These changes have helped Ontario in building a cleaner, modern and reliable electricity system.

In 2003, they made a transition from FiT/micro FiT to net metering in their long term energy plan as a way forward. It allowed the residential, commercial business owners and private developers to establish a grid connected solar rooftop system wherein they can generate electricity and supply it to the grid.

Going forward solar electricity will be a mainstream energy resource with an integral part of Canada energy mix. The solar electricity industry will be sustainable with no direct subsidies and operating in a supportive and stable policy and regulatory framework that would recognize the true value of solar.

Net metering regulation

In 2017 the net metering regulations were updated which included crediting at retail price. Few other key features have been highlighted below:

Maximum system size: The amendments included removing 500 kW size restriction, as earlier the cap on the size of the project was maintained at 500 kW and the limit was extended up to 2 MW except few special cases like energy storage. Energy storage system was also made eligible for storing the excess solar energy produced by the grid connected solar rooftop system.

Metering principle: Majorly net metering principle is adopted.

Business models: Business models that were identified after continuous deliberations included third party ownership and virtual net metering system. The Long term energy plan (LTEP) will enhance Ontario net metering framework. The proposed regulatory measures will come into force from July 1, 2018.

Net metering accounting framework:

In the current regulations Third Party Owned (TPO) systems with PPA are not allowed otherwise it would have helped in addressing the barrier of huge upfront cost for the solar PV installation can be addressed. Allowing TPO system with PPA is under discussion. With appropriate measures to protect interest of both; consumer and utility, TPO can be allowed to own and operate GRPV systems. The new framework also brings virtual net metering into picture which will provide a platform for thinking out of the box and new areas to explore in solar net metering. An independent electricity system operator is will develop the program to support the grid integration challenges, future policies which would further hep in collaboration within the sector.

Legislative and regulatory action

The amendments to Ontario Energy board was made on November 14, 2017 and the final regulatory measures were posted on November 28, 2017. The proposed changes included enabling TPO and

VPM demonstration projects, to enhance customer protections that would support the introduction of third party ownership arrangements and to ensure the proper renewable energy generation facilities.

A snapshot has been provided below which captures key features of new regulation.

Table 24: Key features of Ontario NEM regulation

Sr. No	Section as per Ontario NEM regulation	Sub section	Description
1.	General definition	▸ Eligible electricity ▸ Eligible generation source ▸ Eligible generator	▸ Eligible electricity: The electricity that meets the criteria as per specified power quality standards and may be injected into a distributor's distribution system by an eligible generator ▸ Eligible generation source: List of generation sources, from which net metering benefits can be accrued ▸ Eligible generator: Entity/individual generating electricity in own/others' premises abiding by applied business models and commercial settlement mechanisms. Few of the criteria may be: o the generator generates the electricity primarily for the generator's own use; o the generator generates the electricity solely from a renewable energy source; o the generator conveys the electricity that is generated directly from the point of generation to another point for the generator's own consumption, with/without reliance on the distributor's distribution system; o the generator conveys any electricity that is in excess of what is consumed by the generator into the distributor's distribution system; and o the generator is not a party to any contract or agreement, other than a net metering agreement to which this Regulation applies, that provides for the sale, in whole or in part, of the electricity that the generator conveys into the distributor's distribution system
2.	Application	▸ DISCOM/utility checklists to include an eligible generator under net metering scheme	▸ Commercial aspects: List down different commercial criteria from DISCOM perspective against which a eligible generator can reap commercial benefits through net metering ▸ Technical aspects: List down different technical criteria from DISCOM perspective against which a eligible generator can reap commercial benefits through net metering
		▸ Methodology to account for net power from DISCOM perspective	List down the following parameters: ▸ Settlement period ▸ Methodology to account the net-generation ▸ Accrual accounting methods(if any) ▸ Business models with stakeholder accountabilities to be considered for net metering benefits
3.	Exception to applicability of	Mention diff types of distributors & generators not falling	Cases to be developed for three types of consumers to mention exception clauses: ▸ Residential

	clauses for application	under the clauses mentioned in 1 & 2 for availing net metering benefits	► Commercial ► Industrial
4.	Existing PPAs/agreements/renewal	Mention validity clauses for an existing agreements between generator and distributor	List down different possible scenarios on validity of the existing contracts. Few of them can be: ► Until the agreement expires ► Agreement expired but application for renewal has been submitted before final due date etc. Mention the cases against which agreements between a generator and distributor can be renewed. Few examples are: ► Both the parties agreed to renewal ► In case of system modifications/additions, though both parties agreed – the formal procedure followed during first time system commissioning needs to be followed ► The type of new agreements are analogous to the old one and there are no significant policy changes in between ► All features of agreements should conform to the NEM regulations and regulation should define criteria for the same(a template format may be given)
5.	Cancellation of existing agreements to go for new agreements	New agreement signing check list	If a customer is an eligible generator who has an existing net metering agreement with a distributor and wishes to convey eligible electricity into the distributor's distribution system for the purpose of being billed on a net metering basis in accordance with this Regulation rather than in accordance with the agreement, the customer may do so by cancelling the agreement in accordance with specific criteria(part of regulation), and at the same time informing the distributor that the customer wishes to convey eligible electricity into the distributor's distribution system for the purpose of being billed on a net metering basis under a new agreement.
6.	Special clauses for retail contract	Identify all applicable clauses under which all retail contracts will fall for agreements	Few of the examples of the special clauses are : A customer who has a contract with a retailer of electricity may enter into an agreement with a distributor to be billed on a net metering basis if, ► the customer is an eligible generator; ► the customer is billed under the bill-ready form of distributor-consolidated billing pursuant to the Retail Settlement Code; and ► the retailer confirms to the distributor that the retailer and the customer have an agreement that allows the customer to convey eligible electricity into the distributor's distribution system for the purpose of being billed on a net metering basis
7.	Account Billing & settlement mechanisms	Develop a build case to simply accounting mechanisms	Methodology for settling bills and passing benefits to users. A sample case will be as follows: A distributor shall calculate, for a billing period, the amount of the bill of an eligible generator who is billed on a net metering basis in the following manner: ► In any billing period when, $(D + E) \leq C$ the distributor shall use the following formula: $A = B + C – (D + E)$ ► In any billing period when,

			(D + E) > C the distributor shall use the following formula: A = B For the purposes of this section, A is the amount of the eligible generator's bill for the billing period, B is the total amount of those charges for the billing period that are not calculated on the basis of the eligible generator's consumption of or demand for electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class, C is the total amount of those charges for the electricity consumed from the distributor's distribution system by the eligible generator during the billing period that are calculated on the basis of the eligible generator's consumption of electricity or demand for electricity, including charges for the commodity of electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class, D is the total monetary value of the eligible electricity conveyed into the distributor's distribution system by the eligible generator during the billing period, calculated on the same basis as the eligible generator's consumption of electricity but not demand for electricity, including charges for the commodity of electricity, but without any adjustment for total losses as defined in the Retail Settlement Code, and E is the amount of any accumulated electricity credits ► For the purposes of B, C and D in subsection an eligible generator's consumption of electricity is to be measured in kilowatt hours ► In calculating the values of B and C in the manner applicable in billing a customer in the same rate class, the distributor shall have no regard to the eligible generator generating eligible electricity or being billed on a net metering basis
8.	Special cases in settlements & accounting mechanisms	► Detail the conditions ► Under which deviations from normal procedures can be allowed	Few of the sample cases may be: ► In any billing period when the kilowatt hour reading on the meter at the end of the period is greater than or equal to the kilowatt hour reading on the meter at the beginning of the period, the difference between the two readings is deemed to constitute the amount of electricity that the eligible generator consumed from the distributor's distribution system for the purpose of calculating C, and a value of $0 is assigned to D. ► In any billing period when the kilowatt hour reading on the meter at the end of the period is less than the kilowatt hour reading on the meter at the beginning of the period, the difference between the two readings is deemed to constitute the amount of eligible electricity

			conveyed into the distributor's distribution system by the eligible generator for the purpose of calculating D, and a value of $0 is assigned to C. ► If the eligible generator has a contract with a retailer, the distributor shall modify the calculation of C and D according to the following rules ○ In any billing period when the portion of the bill covering competitive electricity services for the eligible generator constitutes a charge or is equal to $0, the amount of the charge or $0, as the case may be, shall be used as the charge for the commodity of electricity for the purpose of calculating C, and $0 shall be used as the charge for the commodity of electricity for the purpose of calculating D. ○ In any billing period when the portion of the bill covering competitive electricity services for the eligible generator constitutes a credit, the amount of the credit shall be used as the charge for the commodity of electricity for the purpose of calculating D, and $0 shall be used as the charge for the commodity of electricity for the purpose of calculating C.
9.	Cancellation clause	Detail the conditions under which an eligible consumer can apply for cancellations and at the same time what are the modalities once a consumer discontinues net metering connection.	Few of the clauses may be: ► A customer may cancel a net metering agreement with a distributor at any time by giving 90 days' notice in writing to the distributor ► A customer who is an eligible generator and who has cancelled a net metering agreement under above clause may not, for 12 months after the cancellation, be permitted to convey eligible electricity into the distributor's distribution system for the purpose of being billed on a net metering basis.

5.5.2 Key Takeaway

The Canadian experience is very much relevant in terms of clarity and detailing required in regulation. Key learnings from Ontario regulations are provided below:

- Regulatory provisions related to eligibility and detailed definition in case of multiple business models will be required
- PPA related clauses - Cancellation and renew of existing contracts needs to be defined. It will be very useful if standard agreements are prepared for different business models with standardised terms and conditions for cancellation and renew.
- Special cases for billing and commercial settlement – It will be useful for stakeholders if examples of accounting and billing settlements are provided for different business models

Gap Assessment

6 Gap assessment within existing regulatory framework

The following section deliberates what changes are required in proposed GRPV model regulation based on international experience and cases studies observed in India in recent times. The identified gaps which need review while framing proposed model regulation are listed below:

1) Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity
2) Different limits on GRPV capacities connected to DT requires review

3) Limited business models options available to consumer and developers, limited scope to DISCOMs in present scenario
4) Definition of premises and Solar roof-top PV systems needs review owning to future possibility of different scenarios
5) Limited provisions on real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems
6) Present PPA or connection agreement need additional aspects related to change in ownership and flexibility in existing PPA/connection agreement
7) No remuneration for excess generation in present energy accounting and commercial settlement principles
8) Metering and communication requirements needs review to provide greater visibility on solar generation to DISCOMs and system operations

To mitigate these gaps, following measures has been proposed for consideration in the GRPV model regulation based on the recent cases coming up in India and based on the international experience. The different relevant cases has also been provided supporting the mitigation measures.

1) Allowing higher system size by relaxing or removing present limits based on sanctioned load and maximum GRPV capacity

The present regulations (model and state) has put restrictions on GRPV capacity like certain percentage of sanction load, and individual maximum capacity that can be commissioned. Though, model net metering regulation, 2013 has not put any restriction in terms of sanction load, the few state regulations has put certain restrictions. The limit on GRPV system capacity in terms of sanctioned load differs from state to state; ranging from 40% to 100% under net metering. Further, the maximum capacity of 1 MW can be set up in India under net metering arrangement.

There are instances where higher capacity is allowed under net metering arrangement. Uttar Pradesh Electricity Regulatory Commission (UPERC), invoked the "Power to Relax" Clause of its Solar Rooftop Regulations and allowed to set up GRPV systems more than 1 MW under net metering. The details are provided in the table below:

Table 25: Cases where UPERC has allowed GRPV systems above 1 MW

Sr. No.	Petitioner	Project Size Allowed (MW)	Sanctioned Load/ Contract demand of the facility (MW)	Date of order
1.	Ordnance Factory, Kanpur	5.00	22.00 MVA	01.06.2017
2.	Hindustan Aeronautics Ltd., Kanpur	2.90	2.90	18.12.2017
3.	Hindustan Aeronautics Ltd., Amethi	1.75	5.00 MVA	18.12.2017
4.	Jhanshi Workshop, North-Central Railway	1.20	2.945 MVA	18.12.2017
5.	L.B.S. International Airport, Varanashi	2.00	2.00 MVA	18.12.2017
6.	Sukhir Agro, Shahjahanpur	3.40	3.80	18.12.2017
7.	Hindustan Aeronautics Ltd., Lucknow	4.00	12.21	23.01.2018

From above table it is clear that the though the project size is greater than 1 MW, still, it is less than or equal to their sanctions load/ contract demand. Being technically feasible these higher capacity systems were allowed. Also, all these petitioners are central public sector undertakings. In the past, there are also cases where despite higher capacity is possible, the same is not allowed by Commission. These cases are provided as a reference below:

Case No 133 of 2016 (Maharashtra Metro Rail Corporation Ltd. (MMRCL) vs Maharashtra State Electricity Distribution Company Limited & Maharashtra State Electricity Transmission Company Limited)

In another case, Maharashtra Metro Rail Corporation Ltd. (MMRCL) applied for net metering arrangement for 23 MWp at different locations; metro stations, open land; boundary walls and viaducts in the city of Nagpur. However, the connectivity to the grid was at two locations only; one at 132 KV and another at 33 KV. The present regulatory framework in Maharashtra allows maximum 1 MW capacity at single location. Further, GRPV systems up to 40% of the DT capacity can be installed. Due to these limits, maximum 2 MW capacity was possible against potential of 23 MW under present net metering regulation. Maharashtra State Regulatory Commission (MERC) in its order dated January 16, 2018 in case No. 133 of 2016 had not allowed the demand of Nagpur Metro under present net metering regulation and advised to explore other options like gross metering and open access available for GRPV systems higher than 1 MW.

Case No 163 of 2017 (Cleanmax Enviro Energy Solutions Pvt. Ltd vs Maharashtra State Electricity Distribution Company Limited)

Another interesting case, where a consumer applied for availing benefits of different regulations; net metering regulation as well as open access regulation simultaneously in Maharashtra. Cleamax Enviro Energy Solutions Pvt. Ltd. has installed GRPV system of 991 KW (against potential of 1027 KW, to meet the net metering criteria), at one of its client, Asahi India Glass limited (contract demand of 7000 KVA) who was also availing open access for 3000 KVA from conventional source under group active arrangement.

As the GRPV capacity was below 1 MW, Asahi made application for Net metering arrangement to Maharashtra State Electricity Distribution Company Limited (MSEDCL). Due to no response from MSEDCL, Cleanmax moved to MERC to provide clarification that no such limitation is placed for granting permissions to open access consumers for availing net metering arrangement. MERC in its order dated June 12, 2018 in case no. 163 of 2017 denied permission by saying that net metering and open access are two separate arrangement and cannot be availed simultaneously by the same consumer which will also arise various issues related grid security, accounting billing and settlement etc.

Order dated October 09, 2017 on determination of benchmark capital cost for solar PV and solar thermal power projects applicable during FY 2017-18 and resultant generic levelized tariff, Rajasthan Electricity Regulatory Commission (RERC)

RERC, in its suo-motu order dated October 09, 2017 while issuing generic tariff order for FY 2017-18 has determined generic tariff for grid connected solar roof-top projects; both, ground mounted and solar roof top for capacity less than 5 MW keeping in view the spirit of para 4.3.1 of the bidding guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects on long term basis issued by Government of India on August 03, 2017 which suggests competitive route for long term procurement of electricity by procurers from grid-connected solar PV power Projects having size of 5 MW and above.

<u>International perspective</u>

Internationally, based on experience earlier restrictions on system capacity were relaxed and higher size capacity were allowed for GRPV system. Like, Canada had removed cap of 500 KW of system size. In North Carolina states of USA, the system size limit was 20 KW for residential and 100KW for commercial consumers. In 2007, the North Carolina legislature, through Session Law 2007-397 requested that the PUC consider raising the net metering generation cap to 1 MW which the commission agreed stating the decision will help in furthering renewable energy deployment.

In California, higher limits are allowed for net metering up to 10 MW. In California higher system capacity (more than 1 MW) can be allowed depending upon the consumer category, their demand and technical feasibility of interconnection. Further, under the bill credit transfer program authorized by Public Utilities Code 2830 GRPV systems of higher capacity for e.g: 5 MW capacity owned by, operated by, or on property under the control of, a local government or university are allowed in California.

In Mississippi, USA, for residential customers, net Metering is limited to 20 kW and for non-residential customers, Net Metering is limited to 2 MW. Residential systems are limited to 20KW and must be located on customer's premises. Non-residential customers can aggregate generation systems within their premises up to 2 MW.

While in India the system capacity allowed based on sanctioned load vary from 40% to 100%, in countries like Brazil and few state in USA like California Virginia the limit is 100%. In case of other states like Colorado, especially for shared renewables the limit is 120% of the customer's average annual consumption.

In a nod to utility concerns that customer-sited distributed represents lost revenues, many states followed the practice of limiting the total aggregate capacity eligible for net metering based on peak demand. The most common program cap is based on a percentage of the utility or state's peak demand, capacity, or load in a given reference year. Typical range is from 1.5% to 5% in USA. Many states in USA have increased their caps over time as distributed PV penetrations have increased, or modifications have been made to net metering laws.

As seen from the international scenario and present cases coming up in India it is clear that:

- Higher capacity can be allowed as such provision has been amended in some countries and such higher capacities are also coming up in India and are expected to increase in near future.
- The dispensation for allowing higher capacity under net metering can be made based on consumer category or special cases where large campus is available like old government offices or commercial establishment, institutes and industries etc. to harness solar roof top potential as learnt from international cases mentioned above.
- There can be cases where the GRPV systems would be scattered within one premise or different premises within one city or within one utility area, aggregation model for all such capacities would be required.
- In some cases the consumer can avail additional benefit of open access or other scheme available under different regulations, other than solar roof top and decision whether the same can be allowed needs to be taken.

However, while allowing higher capacities will also raise certain issues. Addressing such issues would be critical for deployment of GRPV systems in the model regulation. Few of such Issues or challenges that need to be addressed and their mitigation measures are provided below:

- In case the consumer can consume most of energy generated from such high capacity GRPV plants (in case no restrictions are put on GRPV capacity), then adequate accounting and commercial settlement needs to be designed.
- In other case where consumer demand is very less than the GRPV capacity possible then to harness such potential, the DISCOM can be allowed to procure power from such GRPV systems on the basis of either gross metering or reverse bidding.
- It is also possible that GRPV capacity installed is very less than the sanctioned load/ contract demand , similar to the UP case mentioned in earlier chapter, then such capacity should be allowed
- The cost of upgrading existing infrastructure if required to accommodate higher capacity is a contentious issue as who will pay the cost; consumer or DISCOM. The cost can be recovered based on "beneficiary-to-pay" principle. Other option would be to allow recovery of such cost through Annual Revenue Requirement if DISCOM has benefit in serving more consumer or improve supply reliability by upgrading the existing infrastructure.
- If open access is allowed either partial or fully, adequate compensation would be required for DISCOMs such as cross subsidy surcharge and additional surcharge. Presently, these charges are exempted under present net metering regulatory framework.
- From system operator or DISCOM point of view, if GRPV systems of higher capacities are allowed then regulatory provisions are required for real time visibility of their solar generation. Presently, for certain capacity, say, 20 KW and above, to be decided after consultation, AMI arrangement can be installed. From future perspective, as technology is changing fast and also becoming affordable, smart meters can be made compulsory for each GRPV system.

2) DT connection capacity for Grid connected rooftop solar

The present regulatory framework has put restriction on maximum capacity that can be connected to single DT. The main reason was apprehension about possible reverse power flow. Also as the present distribution network was not designed for reverse power flow, it was envisaged that the limit can be reviewed after carrying out technical study at suitable point of time.

Practically, as learnt from the stakeholder consultation, the limit put on DT loading has not been exhausted so far, therefore, the exact impact of putting more solar generation on a particular DT has not been evaluated. Neither the DTs are monitored on real time. Also specific studies has not been carried by neither DISCOM nor has been seen as insisted by regulator.

Considering issue of reverse power flow and based on the technical study, following provisions can be considered of including in the model regulation:

- It is obvious that load flow study can help in understanding the impact of GRPV deployment on reverse power flow. Based on the load flow study the limit can be reset to acceptable level.
- Other option can be to put limit on GRPV systems than can be installed on a particular DT, but also make provision of additional DT if applications for GRPV more than the limit has been received on particular DT.
- Special monitoring of all such DTs will be required to collect real time data where GRPV systems are deployed which will help in further analysis to review the limit.
- Further suitable security measures are required at consumer level and at DT level so that monitor the power flow on real time basis.

3) Innovative and emerging business models

The existing regulations (both, model regulation and state regulations) promote largely self-consumption framework for the power generated by the GRPV system and set the principles for the energy accounting and commercial settlement for the net import/ export of electricity received/fed in to the grid. Internationally, additional business models, depending upon capital investment, responsibility of Operation and Maintenance and parties involved in settlement are very popular. Typical structures of the possible business models, prevalent in USA are provided in the table below:

Table 26: Structure of business models prevalent in USA

Ownership structure	Metering structure	Revenue structure
► **Self-owned**	► Gross metering	► Solar lease
► **Third party**	► Net metering	► PPA
► **Utility owned**	► Virtual	► Self-use

Thus, there is a need to look beyond the prevalent business models to promote and facilitate new and innovative models for installation of GRPV systems, for eligible consumers, e.g. in the urban centres of India like Delhi, with inadequate rooftop area/inaccessible rooftops but are willing to participate in group solar roof top and share the benefits.

Among emerging business models types, few are DISCOM anchored/centric model, which will critically cover the following areas:

- Standardisation of the mechanisms adopted by DISCOMs for real time monitoring of solar generation, capacity of interconnected systems and application status are necessary.
- Procurement practices for net meters, metering specifications for procurement, maintenance procedures, testing procedures for the DISCOM.
- Defining and standardising the investment recovery framework for the procured net-meters or upgraded infrastructure is necessary.

- Parameters defining quality of power such as harmonics, voltage, synchronization, flickers, DC injections and frequency etc. should be defined and standardised.

Unlike developed countries, the present regulatory framework does not support multiple parties willing to install solar roof-top like housing colony or apartment system and participate in commercial settlement. The role of DISCOMs is also limited whereas they can be more proactive in proliferation of GRPV system. Multiple options of metering and business models to select from, balancing interest of DISCOMs and consumers will require certain amendments in the present provisions and addition of new provisions which will provide regulatory framework for the new business models and their accounting and commercial settlement for GRPV.

Therefore, the model regulation need changes to accommodate new business models, provide fair and just energy accounting and commercial settlement mechanism, relax restrictions on GRPV system capacities possible based on technical study and adopting suitable safety and operational rules for stable grid operation and harmonize the regulatory framework across country which will help in proliferation of GRPV systems in India.

As seen earlier, the current regulation promotes only two business models; CAPEX & RESCO. Recent developments and market trends indicate that there is a need to include innovative business models in the current regulatory landscape to increase participation for DISCOMs, developers and end users. Thus, utility centric business models through which demand aggregation can be possible and other group/virtual net metering models may be considered in the upcoming regulation.

As different business modalities are working well in Canada, USA and Germany, the business models suitable in Indian context needs to be adopted. Thus, it is suggested to:

- Incorporate innovative business models after stakeholder consultation to understand possible key challenges against proliferation of new business models proposed.
- Devise risk mitigation strategies based on scenario analysis and incorporate those in the emerging business models proposed
- Design metering, accounting and commercial settlement principle for these business models

4) Premises, Solar Roof-top PV plant and inclusion of land in their definition

In few state regulations, the definition of ‘premises’ and ‘roof-top solar system’ has been modified than the definition provided in the net metering regulations 2013 as explained below:

- In case of Gujarat, the definition of ‘premises’ and ‘roof-top solar system’ have been modified where open area on the land is added in the above definition provided in the present net metering regulation, 2013.
- In case, open land is allowed under net metering along with building infrastructure, in some cases, it might be possible to install high capacity GRPV system than the present restrictions – sanctioned load, DT capacity and maximum capacity allowed – which present framework does not allow.

In case of Nagpur metro, above mentioned, around 9 MWp capacity was possible on lands available in their premises. If wall mounted GRPV systems are also added then another capacity of 2.2 MWp is possible.

The Nagpur metro case also raises issue if premises at different locations within same city or jurisdiction of same DISCOM whether the regulation may have provisions either allow it or not allow. It may be a case if a customer has two connection under same consumer category at different location, but, only one location is technically feasible which can cater demand of both the locations. Presently, there is no restriction on ground mounted solar projects. But, capacity above 1 MW can connect with grid trough either gross metering arrangement and reverse bidding. Therefore, in case present restrictions on GRPV systems are relaxed and ground mounted systems are allowed then there are chances that number of ground mounted systems will apply under net metering arrangement. Therefore, following issues needs to be considered while defining premise:

- Adequate regulatory provisions will be required to bring clarity on to what extent utilisation of open land in the consumer premises can be considered and how the generation will be qualified under solar roof-top regulations along with their metering principle, accounting and commercial settlement.
- If premises definition can be modified to accommodate more variations like adjacent premises or premises at different locations but owned by same person.
- If different premises of same consumer are to be allowed the same will be treated as open access which is not allowed for a consumer having sanctioned load/ contract capacity less than 1 MW. Therefore, in such cases, provisions of different regulations are also needed to be considered. Or the premise where the GRPV system is installed can be allowed under gross metering and commercial settlement can be done with its connection at different location. However, this is possible when both the premises are in the same DISCOM area.

5) Applicability clauses for grid interconnection and requirement for system operation

Large penetration of GRPV systems may create technical issues such as reverse power flow, over frequency or under frequency; over voltage or under voltage and reactive power management depending upon the length of network and supply demand situation. Therefore, systems operator must be aware of real time generation from GRPV systems, at least of large capacities. Germany, where the large GRPV system has been deployed, has formulated stringent grid interconnection guidelines and laws to maintain grid stability and standardize power qualities from distributed generation resources.

Presently, the utilities in India lag behind European utilities in terms of real time monitoring of its assets and distributed generation sources connected to their networks which can be attributed to the lower GRPV penetration level. Although, the real time data monitoring requires extensive capital expenditure and technological advancements, regulatory directive might be helpful for utilities which are slowly moving toward grid digitisation and enhancement of present communication protocols.

CEA Technical standard for interconnection to grid states with regard to generating stations using inverters that Measurement of harmonic content, DC injection and flicker shall be done at least once in a year in presence of the parties concerned and the indicative date for the same shall be mentioned in the connection agreement.

IEEE Standard 1547 (2003), which is the primary document on interconnection of systems also have reference to periodic tests among general requirements, responses to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning.

The upcoming regulation also needs provisions to refer such standards to address interconnection related issues.

<u>International perspective</u>

In Germany, the Renewable Resources Act provides guidelines for interconnection, and mandates the connection of renewable systems on priority basis. VDE 4105 Code of Practice is mandatory from January 2012 for interconnection with the low-voltage grid.

Mainly, there are three major directives in Germany that mandates GRPV plants to meet technical standards for their interconnection with the grid:

- The BDEW medium voltage directive
- The VDE code of practice
- The Renewable Energy Sources Act (EEG) 2012

The BDEW medium voltage directive

Since January 1, 2009, the revised medium voltage directive has been in effect for all distributed power generation plants that feed at the medium voltage level into the power distribution grid – i.e., typically for plants with approximately 200 kW of power and more. Its requirements may be divided into four stages, which successively came into effect.

- Participation in feed-in arrangement - If a section of the relevant medium-voltage grid or higher level transmission grid is temporarily overloaded, the distribution grid operator sends a ripple control signal which must be implemented as limitation of the fed-in active power (typically 60, 30 or zero percent of the rated power). The respectively required limitation must be implemented by the inverter within 60 seconds.
- Active power reduction in case of over frequency – Earlier, the PV inverters had to be disconnected from the grid immediately after the power frequency goes beyond he permitted range of frequency. However, due to sudden disconnection of large PV power generation capacities can have a negative effect on the grid stability. Therefore, the invertor now needs to reduce their current power with a gradient of 40 percent per Hertz from 50.2 through 51.5 Hz and only disconnect from the grid above 51.5 Hz. The disconnection limit in case of under frequency remains unchanged at 47.5 Hz.
- Provision of reactive power - The grid operator may demand a displacement power factor between 0.95 and 1 with three variations for the definition of the target value being available to that end:
  - The grid operator specifies fixed target values that the plant operator is required to set.
  - Various reactive power values are set on the basis of an agreed upon time schedule or specified via supervisory control signal by a central control centre of the grid operator.
  - The reactive power percentage is regulated via a characteristic curve – depending on the grid voltage measured at the connection point or the ratio of the currently supplied active power and the nominal power of the inverter.
- Dynamic grid support - The revised medium-voltage directive now requires PV inverters to support the grid in case of an incident by "riding through"[32] voltage drops of up to several seconds and then resuming normal feed-in immediately afterwards (so-called low-voltage ride-through, or LVRT). The inverter behaves passively throughout the course of the error in the limited version. The device also needs to feed reactive power into the power distribution grid during a voltage drop in the complete version of the LVRT, as it has been required since April 1, 2011. As a result, they contribute to the resolution of the incident and help to trigger the grid protection devices.

The VDE code of practice:

The VDE 4105 code of practice has been in place since August 1, 2011, and binding since January 1, 2012, and affects all GRPV plants that feed in to the low-voltage grid, which means the vast majority of them. The code requires following requirements to comply:

- Active power reduction in case of over frequency - PV plants are not disconnected immediately when the power frequency is too high, but is reduced gradually. The permissible frequency band will be then expanded to a range from 47.5 to 51.5 Hz. The current feed-in power must be reduced by 40 percent/Hz. The plant will be disconnected only if 51.5 Hz is attained.
- Connection criteria and permissible unbalanced load - A maximum plant power of 13.8 kVA results when using single-phase, uncoupled inverters (3 x 4.6 kVA) only. Therefore, at least the proportion of the power exceeding 13.8 kVA must be designed with three-phase or communicatively coupled single phase inverters in larger plants.
- Grid and GRPV plant protection - Set values for the G/P protection:

[32] In electrical power engineering, fault ride through (FRT), sometimes under-voltage ride through (UVRT) or Low voltage ride through (LVRT) , is the capability of electric generators to stay connected in short periods of lower electric network voltage

- Deactivation limits: Voltage drop protection (U < 184 V
- Voltage increase protection (U >) > 253 V
- Voltage increase protection (U >>) > 264.5 V Frequency drop protection (f < 47.5 Hz
- Frequency increase protection (f >) > 51.5 Hz Reconnection limits: Voltage greater than 195.5 V and less than 253 V Frequency greater than 47.5 Hz and less than 50.05 Hz

The Renewable Energy Sources Act (EEG) 2012:

The Renewable Energy Sources Act (EEG) as amended mid-2011 and valid from the beginning of 2012 included new requirements regarding the grid integration of PV plants.

- It stipulated that plants with more than 100 kW peak power must participate in feed-in management and, at the same time, extends this demand to smaller plants – of course in less stringent form
- Furthermore, operators of PV plants with less than 30 kWp of power were allowed to skip installing the device for remote power limitation if they agree to accept limitation of feed-in power to 70 percent of the installed generator power.
- As for the obligation to retrofit, both power categories also differ: plants between 30 and 100 kWp were to be retrofitted by the end of 2013, if they were commissioned after December 31, 2008.
- There was no obligation to retrofit plants with less than 30 kWp.

Based on the German Experience, especially in terms of safety of grid operations the key observations are summarised below:

- Visibility and control over solar generation beyond certain capacity is must to the DISCOM or system operator in view of requirement of stable grid operation. For low capacity systems certain restrictions should be put so that minimum level of feed-in is maintained
- The GRPV invertor system must be able to respond to the system requirement and follow instruction of the area system operator and their technical specifications needs to be designed accordingly
- Going forward, stringent interconnection standards and safety measures will be required when more and more GRPV systems will get added in distribution network
- A monitoring framework for system parameters, reactive power control are required – Mentioning allowable cumulative GRPV capacity connected to a DT only from reactive power injection perspective might be helpful
- It also needed to devise a short, medium and long term roadmap for actions required by DISCOMs at different levels of reactive power injection in the main grid based on the reporting/monitoring tool's data.

6) Existing PPAs/connection agreements clauses and mechanisms for renewal / cancellation

In the evolving scenario of GRPV segment in India, involvement of RESCOs has become more and more popular through OPEX models in which multiple beneficiaries take part in owning, maintaining GRPV systems and settling commercial agreements respectively. Thus DISCOMs and developers normally sign PPAs based on the mutually agreed terms and conditions for 25 years as useful life of solar panels is 25 years. In California, the agreement period is 20 years. However, there is no compulsion on 20 year contract period.

Also, in India, the GRPV market is still in its nascent stage with limited consumer awareness while looking at emerging business models, it is important to help consumers aware of different business modalities. Thus cognizance of different versions of PPAs for different business models will help consumers validate agreement clauses with DISCOMs or developers. Thus guidelines on agreement signing check list for different business models and also for different scenarios such as new agreement after existing PPA cancellation etc. need to be added in the coming regulations.

In few states like Tamil Nadu, Uttar Pradesh after serving 90 day notice the connection agreement can be cancelled. In J&K, Punjab, Manipur and Mizoram, the notice period is of one month.

International perspective

In Ontario NEM regulations existing PPAs/agreements/renewal is done in the following manner. The PPA should List down different possible scenarios on validity of the existing contracts. Few of them can be:

- Until the agreement expires
- Agreement expired but application for renewal has been submitted before final due date etc.
- Mention the cases against which agreements between a generator and distributor can be renewed. Few examples are:
- Both the parties agreed to renewal
- In case of system modifications/additions, though both parties agreed – the formal procedure followed during first time system commissioning needs to be followed
- The type of new agreements are analogous to the old one and there are no significant policy changes in between and the tariff agreed must be different and must reflect the reduced cost of solar plant.
- All features of agreements should conform to the NEM regulations and regulation should define criteria for the same (a template format may be given)

Considering the international experience, following modifications are suggested which can be incorporated in the proposed model regulation.

- Clauses on sold out GRPV premises.
- Guidelines in case of change of ownership structures in the plant life.
- Future possibility of additional capacity installations due to change in regulatory restrictions or purchase of adjacent area by consumer.
- Expiration of the current PPAs (if the business model or arrangement is for short duration like in case of modular plants where the contract period is till the payback period with clause of change in ownership).
- Provisions related to adequate notice period should be made if a consumer and developer want to discontinue with the present agreement

7) Energy accounting and commercial settlement mechanisms

Under present model regulation, 2013, the consumer accrues no benefits for excess generation. Therefore, the existing energy accounting and commercial settlement mechanism also needs suitable revision to compensate all stakeholders in a reasonable manner possible. The mechanism should also suitably capture the stakeholders' needs and also address their issues by forward looking at the sector's transition.

Few concepts, such as gross metering, community metering and virtual net metering are presently under discussion which can further enable uptake if it can be a part of the regulatory mandate. Few SERCs have notified the provisions of gross metering as part of their solar rooftop regulatory framework. Other metering methods needs to be suitably developed and adopted based on the new and emerging business models.

RERC (Connectivity and Net Metering for Rooftop and Small Solar Grid Interactive Systems) Regulations, 2015, the excess energy fed into grid is compensated at variable Feed-in-tariff to be determined by the Commission every year. The relevant excerpts are reproduced below:

> "Provided that in the event the electricity injected exceeds the electricity consumed during the billing period, such excess injected electricity shall be paid by the Distribution Licensee at feed in tariff determined by the Commission from time to time for Solar Photo Voltaic generation in next billing period provided that such export is above 50 units….."

Though the provision of variable rate for compensation will reflect market trend and benefit DISCOM if the current trend of reducing prices continue. However, from developer or consumer point of view, this can be treated as regulatory uncertainly as predicting future rate he will get will be dynamic. Therefore, balancing of stakeholder's interest in reasonable way is very critical for attracting consumer to opt the GRPV systems.

International perspective

In USA different state has followed different methods for energy accounting and commercial settlement. In Hawaii, Hawaii Public Utilities Commission eliminated the retail rate remuneration for new net metering customers. The new scheme replaces old net metering regulation and leaves PV system owners to choose between a grid-supply option and a self-supply option.

- In case of grid-supply option, the customers receive a fixed credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid.
- The self-supply option is primarily aimed at creating solar owners who do not export generation to the grid, though the commission stressed no non-export design should prevent solar systems from providing grid.
- In Denmark, premium tariff system promotes the generation of electricity from renewable sources based on bonus payments. The operators of renewable energy plants usually receive a variable bonus, which is paid on top of the market price. The sum of the market price and the bonus shall not exceed a statutory maximum per kWh, which depends on the source of energy used and the date of connection of a given plant. FiT for the excess electricity is guaranteed during 20 years, with a decreasing value after 10 years.

Commercial settlement period and rate for energy injection

A table on different provisions related to settlement period and rate in different states of USA are provided below:

Table 27: Settlement period and rate for excess energy in different states of USA

Sr. No.	Name of the state	Commercial settlement period and rate for energy injection
1.	Virginia	Credited to customer's next bill at retail rate. After 12-month cycle, customer may opt to roll over credit indefinitely or to receive payment at **avoided-cost rate**.
2.	Minnesota	Systems under 40 kW: Reconciled monthly; customer may opt to receive payment or credit on next bill at the **retail utility energy rate**. For systems 40 kW -1 MW, NEG is credited **at the avoided cost rate**, or customers may elect to be compensated in the form of a kWh credit. Excess credit will be reimbursed at the end of the calendar year at the avoided cost rate
3.	California	Credited to customer's next bill at retail rate. After 12-month cycle, customer may opt to roll over credit indefinitely or to receive payment for credit at a rate equal to the 12-month average spot market price for the hours of 7 am to 5 pm for the year in which the surplus power was generated.
4.	Indiana	Credited to customer's next bill at **retail rate**; carries over indefinitely
5.	New Mexico	Either credited to customer's next bill at avoided cost rate or excess kWh generated are credited to the account and rolled over indefinitely. If customer leaves the utility, unused credits are paid out at the **avoided cost rate**

In Canada, as per Ontario regulation, a DISCOM shall calculate, for a billing period, the amount of the bill of an eligible generator who is billed on a net metering basis in the following manner:

In any billing period when, $(D + E) \leq C$ the distributor shall use the following formula: $A = B + C – (D + E)$. In any billing period when, $(D + E) > C$ the distributor shall use the following formula: $A = B$

For the purposes of this section,

A is the amount of the eligible generator's bill for the billing period,

B is the total amount of those charges for the billing period that are not calculated on the basis of the eligible generator's consumption of or demand for electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class,

C is the total amount of those charges for the electricity consumed from the distributor's distribution system by the eligible generator during the billing period that are calculated on the basis of the eligible generator's consumption of electricity or demand for electricity, including charges for the commodity of electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class,

D is the total monetary value of the eligible electricity conveyed into the distributor's distribution system by the eligible generator during the billing period, calculated on the same basis as the eligible generator's consumption of electricity but not demand for electricity, including charges for the commodity of electricity, but without any adjustment for total losses as defined in the Retail Settlement Code, and

E is the amount of any accumulated electricity credits

For the purposes of B, C and D in subsection an eligible generator's consumption of electricity is to be measured in kilowatt hours. In calculating the values of B and C in the manner applicable in billing a customer in the same rate class, the distributor shall have no regard to the eligible generator generating eligible electricity or being bill on a net metering basis.

Retail tariff and charges applicable to GRPV system user

In developed countries, with proliferated GRPV systems, tariff design has moved from volumetric tariff to fixed cost basis. This was in response to increased distributed generation to ensure DISCOM's recovery of fixed cost. For demonstrating the way retail tariff are redesigned in the context of high level of penetration of distributed generation which might be the case in near future in India few examples has been provided in the table below:

Table 28: Tariff applicable for GRPV system users in USA

Sr. No.	Name of the state	Charge for recovery of fixed charge	Details
1.	Massachusetts	Monthly minimum reliability contribution	This minimum contribution shall ensure that all DISCOM customers contribute to the fixed costs of ensuring the reliability, proper maintenance and safety of the electric distribution system. This monthly minimum contribution is such that (i) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (ii) (ii) does not excessively burden ratepayers; (iii) (iii) does not unreasonably inhibit the development of GRPV
2.	California	Connection fee	Previously, PG&E connected residential customers' solar systems to the company's grid for free. When the 5% penetration milestone was passed for adopting solar energy in California, the PG&E customers were imposed fee of $75-145 if they want to connect their solar arrays to the PG&E electricity grid.
3.	Arizona	Residential Demand Charges	The Salt River Project (SRP), a utility in Arizona, is one of the few utilities in the country to impose residential demand charges, and they are

			mandatory only for customers with solar power systems. SRP levies a fixed charge of $32 per month for solar customers, plus a demand charge ranging from $8 to $33 per kilowatt in the summer, combined with an electric rate as low as only 3.9 cents per kWh off-peak.

Based on the discussion on above key factors besides others, there is adequate scope for revision in present model regulation based on experienced gained- both in India and from developed countries as well.

As per net metering regulation, 2013 the excess generation during the settlement period was not compensated. The SERCs who came up with net metering regulation afterwards tried to address the issue by allowing excess generation to be settled at some predefined rate like FiT , APPC so that consume will also get due benefit.

In India, where the present tariff structure is volumetric basis, and the tariff determination is altogether a different procedure followed under different regulatory framework and where fixed cost is charged in a different way, like, per connection basis or per KW basis, is constrained by legacy issues like cross-subsidy and inefficiencies and required to operate in a different socio-economic environment.

However, in future, more and more solar penetration is certain as the cost of GRPV systems is reducing and retail tariff is increasing in subsidized categories, but, is not reducing in subsiding category the way it should reduce. Therefore, the tariff re-design will be much needed exercise at that time.

From above discussion, it is clear that:

- The consumer should be compensated reasonably when excess generation is fed into the grid to promote solar roof top.
- Also, the DISCOMs should be allowed to recover their fixed cost in a way suitable in Indian context.
- The emerging business model will also require innovative settlement principles as the no. of parties will be more and the relative complexity will be higher for multi-stakeholder involvement which the regulation must address through commercial settlement.

Once new business models will be considered, sample cases needs to be provided to showcase how settlement will happen among various stakeholders. A sample case is provided above as per Ontario Regulation.

8) Metering, communication arrangements and procurement guidelines for DISCOMs

Under the current landscape, different states have specified varied specifications for metering, communication protocol and arrangements. From simple MRI to AMI compatible (for systems above certain capacity). Moreover, for real time monitoring of GRPV systems, it is required to have advanced metering and communication arrangement by DISCOMs, at least, for above certain capacity, say, 20 KW, to be decided after stakeholder consultations to monitor potential impact on grid stability and reactive power injections.

In view of real time monitoring of solar generation, smart meters or meters with AMI/AMR facility are required so that DISCOMs or system operator can have visibility over solar generation when large scale deployment of GRPV system is envisaged.

Presently, consumer can purchase meter from DISCOM or can also buy meter directly from the market. In case of Karnataka, the list of vendors and price is fixed by BESCOM and provided the information on their website for convenience of consumer. If DISCOM purchases meter of the required specifications, in bulk, then the cost may come down and will ultimately benefit consumer. Further, the meter will be tested and kept ready for provide interconnection when consumer applies. There can be option for consume to purchase meter from market, however, like, Karnataka, DISCOM should made available the list of vendor duly selected from competitive bidding meeting the technical specification and regulatory requirement.

International perspective

In California, the three big California utilities moved to smart meters around 2012-13. Thus, any consumer of these utilities also install smart meters for solar roof-top, though, not compulsory.

In case of Germany also, big German utilities such as E.ON and Energiewende are moving towards 100% smart metering as there's been a progressive shift in the energy mix with the inclusion of more distributed generation (mainly solar rooftop).

California Distributed Generation Statistics (California DG Stats) currently includes data for all solar photovoltaic (PV) systems interconnected through the California Investor Owned Utilities (IOUs) net energy metering (NEM) tariffs regardless of capacity. The biggest balancing authority in the Western Interconnection is the California Independent System Operator (CAISO) monitors nearly 10,000 MW of solar PV, mostly utility scale installations. SCADA systems along with allowing grid operators to initiate or update autonomous inverter functions at PV power plants whether a PV plant connects at the high-voltage (38 kV–500 kV) transmission or medium-voltage (4 kV–38 kV) distribution level helps CAISO in grid balancing. CAISO maintains only that Power plants that do not meet the grid operator's SCADA requirements cannot interconnect.

Considering need of real time monitoring from DISCOM and system operation point of view, and recent practice of procuring smart meters for single phase and three phase low tension consumer, following changes can be adopted in proposed model regulation:

- Smart meters/ meters compatible to AMI should be made compulsory for real time monitoring purpose looking at large scale deployment in future
- The DISCOM shall also develop their IT infrastructure for monitoring solar generation
- The regulation may develop a standardised meter procurement process/guidelines for DISCOMs and devise testing measures for them

Disclaimer

7 Disclaimer

- In the preparation of this Report, we have relied upon the information provided to us and have not independently verified any of such information. However, based upon the review of such information we have, wherever necessary, sought the explanations for the key trends and salient features in respect thereof.
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Annexure-IV

Suggested business models for rooftop solar and their impact on utilities

SUPRABHA
SUSTAINABLE PARTNERSHIP FOR ROOFTOPSOLAR ACCELERATION IN BHARAT

SUPRABHA

The World Bank SBI Rooftop Solar TA Program

WORLD BANK GROUP

SBI

GOVERNMENT OF INDIA
MINISTRY OF NEW AND RENEWABLE ENERGY

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Abbreviations

Abbreviations	Definition
BAU	Business As Usual
DT	Distribution transformer
CAPEX	Capital Expenditure
EPC	Engineering, Procurement and Construction
FoR	Forum of Regulators
GoI	Government of India
GRPV	Grid Connected Rooftop Solar
MNRE	Ministry of New & Renewable Energy
NEM	Net Energy Metering
NEM 2013	Net Metering Regulation, 2013
PMC	Project Management Consultant
PPA	Power Purchase Agreement
PSA	Power Sale Agreement
RESCO	Renewable Energy Service Company
RPO	Renewable Procurement Obligation
TA	Technical Assistance

1. Executive Summary

The cumulative rooftop installations capacity as of 31st September, 2017 is only 1861 MW vis-à-vis a cumulative installed solar capacity of 14,163 MW.

In order to support the Government of India (GoI) targets on widespread installation of rooftop solar PV, the World Bank is lending $625 million (under Perform for Results (P4R) lending instrument) to the State Bank of India (SBI) to debt finance Grid Connected Rooftop Solar (GRPV) projects and capacitate various stakeholder involved. As part of the loan, SBI has proposed a Technical Assistance (TA) program through a Project Management Consultant (PMC) under a Ministry of New & Renewable Energy (MNRE)-led Steering Committee to support strengthening market ecosystem with focus on areas of policy, regulation, process alignments and demand creation.

Under this TA program, a study has been commissioned to support Forum of Regulator (FOR) to update Model Net metering regulation developed in 2013 and to develop a "Comprehensive metering and Accounting framework for Rooftop Solar Photo Voltaic in India". The study aims to identify gaps in the regulatory framework based on upcoming business models and international review, available infrastructure for deployment, and impact on various stakeholders; and propose necessary changes in the existing model regulation.

The existing Net Energy Metering Model Regulations, 2013 largely promote self-consumption of the power generated by the rooftop solar system by the consumer. Capital Expenditure (CapEx) and Operational Expenditure (OpEx or RESCO) models are the dominant business models. Due to a few hurdles posed by the existing models, scale-up of the rooftop solar installations in the country has not been achieved.

The existing business models pose the following hurdles to the uptake of the rooftop solar sector:

- Limited capacity of outreach to large number of consumers
- Small unit size rooftop systems
- Lack of confidence among the consumers and financial institutions in the technology and developers due to limited dissemination of knowledge
- Unavailability of a known and reliable agency to back up the installations to improve confidence
- Contractual and payment risks

The low installation volumes in the sector can be attributed to the abovementioned hurdles from the sector. Increased volumes in the rooftop solar sector will allow:

- Lowering of transaction costs and better operations
- Building confidence amongst the stakeholders
- Streamlining the processes - customer acquisition, procurement, quality systems etc.
- Standardization of RTSPV systems and components
- Improving availability of funds from financial institutions
- Accelerating growth in the rooftop sector

Thus, there is a need to look beyond the prevalent business models. It is critical to promote and facilitate new and innovative models for installation of rooftop solar systems, for eligible consumers especially in the urban centres of India, with inadequate rooftop area/inaccessible rooftops etc. However, the present NEM 2013 regulation does not suitably address these challenges. In this dynamic landscape, the existing metering / accounting mechanisms need revision as well to accommodate new & innovative business models.

After detailed analysis of possible combination of business models, the following operationally possible business models are found more relevant in Indian context:

S. No.	Business model

A. Consumer-centric	
1.	Consumer Owned (Cap-Ex model)
2.	Third Party Owned (RESCO Model)
B. Utility-centric	
3.	Consumer Owned (Utility only aggregates)
4.	Consumer Owned (Utility aggregates and acts as EPC)
5.	Third Party Owned (Utility aggregates and acts as trader between the RESCO and Consumer)
6.	Third party Owned (Utility aggregates and acts as RESCO)

Brief about each above-mentioned models is provided below:

- **Consumer Owned (CAPEX model)**
  The consumer invests their own capital for installing a rooftop solar plant.

- **Third Party Owned (RESCO Model)**
  A renewable energy service company (RESCO) invests to install a rooftop solar plant on the roof of a consumer. The consumer in-return of deriving the benefits of rooftop solar pays rent to the RESCO.

- **Consumer owned model (Utility only aggregates)**
  The regular CAPEX model where-in the utility aggregates the demand and bids it out to the lowest bidder for performing EPC.

- **Consumer Owned (Utility aggregates and acts as EPC)**
  The regular CAPEX model where-in the utility aggregates the demand and bids it out to the lowest bidder for performing EPC. The utility signs a back-to-back contract with the EPC for a margin.

- **Third party owned (Utility aggregates and acts as RESCO)**
  The utility aggregates the demand and invests its own capital for acting as RESCO.

- **Third Party owned (Utility acts as a trader between the RESCO and the consumer)**
  The utility aggregates the demand and bids it out to the lowest bidder for acting as RESCO. The utility charges a trading fee for the kWh produced.

A summary of benefits analysis for each proposed business model is provided below:

Table 1: Summary of benefits of proposed business models

S. No	Model	Utility	Consumer	Developer
1	Consumer-owned model (CAPEX)	Loss of energy sale due to influx of rooftop solar	EPC fees	Profit on EPC fee received
			n*T	
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill. Gains the asset	Gains revenue as EPC fee
2	Third-party owned (RESCO) model	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC fees
				n*T'
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill.	Gains the Asset
3	Consumer owned model (utility only aggregates)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC fee received
		Loss of energy sale due to influx of rooftop solar	n*T	Facilitation fees (assuming 2-3% of the total investment)
	Overall	Utility loses consumer but makes revenue on facilitation fees	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current regulations.	Gains revenue as EPC fee and Saves on marketing cost.
4	Consumer Owned (Utility aggregates and acts as EPC)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC Fee (after a margin cut)
		p% on back to back agreements	n*T	p% on back to back agreements
		Loss of energy sale due to influx of rooftop solar		Facilitation fees (assuming 2-3% of the total investment)
	Overall	Utility loses consumer but makes revenue on facilitation fee for aggregation and margin on back to back EPC contract.	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current regulations.	Gains revenue on EPC. Although loses margin, saves on marketing cost and gains payment security.

S. No	Model	Utility	Consumer	Developer
5	Third Party owned (Utility acts as a trader)	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC Fee
		Facilitation fees (assuming 2-3% of the total investment)		Facilitation fees (assuming 2-3% of the total investment)
		p% on all units of energy traded		p% on all units of energy traded
				Revenues from energy sale
	Overall	Utility makes revenues due to energy trading and facilitation fees for aggregation	RESCO model beneficial due to no capital investment	Revenues due to energy sale and cheaper finance due to payment security. Low transaction costs and lower capital cost due to aggregated demand. Also, gains the asset.
6	Third party owned (Utility aggregates and acts as RESCO)	EPC Fee	n(T-T')	
		Revenue from energy sale (y*n)		
	Overall	Utility makes revenue on energy sale to the consumers. Lower cost of procurement due to economies of scale.	RESCO beneficial due to no capital investment	Developer plays no role

Where,

x_n – Gross meter reading for month "n"
y_n – Energy meter reading for month "n"
Δx – Total number of units (kWh) consumed i.e. $x_n - x_n$-1
Δy – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T' – Net billing tariff

2. Background

The existing model regulations, 2013 largely promote self-consumption of the power generated by the rooftop solar system by the consumer. Capital Expenditure (CapEx) and Operational Expenditure (OpEx or RESCO) models are the dominant business models. Due to a few hurdles posed by the existing models, scale-up of the rooftop solar installations in the country has not been achieved.

The existing business models pose the following hurdles to the uptake of the rooftop solar sector:

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The low installation volumes in the sector can be attributed to the abovementioned from the sector. Increased volumes in the rooftop solar sector will allow:

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- Streamlining the processes - customer acquisition, procurement, quality systems etc.
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- Accelerating growth in the rooftop sector

Thus, there is a need to look beyond the prevalent business models. It is critical to promote and facilitate new and innovative models for installation of rooftop solar systems, for eligible consumers especially in the urban centres of India, with inadequate rooftop area/inaccessible rooftops etc. However, the present NEM 2013 regulation does not suitably address these challenges. In this dynamic landscape, the existing metering / accounting mechanisms need revision as well to accommodate new & innovative business models.

The primary consideration for development of business models was based on three parameters namely, Ownership, Operation Expenditure Responsibility (Op-Ex) and Financial Settlement. The ownership is attributed to the party which incurs the entire capital expenditure for the asset. The next criterion – Operational Expenditure – is attributed to the party which pays for the operational expenditure. The settlement consists of only two options – Settlement with Utility or RESCO. In addition to these parameters, two additional conditions were considered -

- High Demand, Small Roof
- Multiple Beneficiaries

Possible combinations of business models for all the variable parameters were identified. A total of 72 combinations exist. Of the 72 identified combinations, four combinations have been identified as operationally possible. The identified business models are as follows -

- Consumer Owned (Cap-Ex model)
- Third Party Owned (RESCO Model)
- Third Party Owned (Utility aggregates and acts as trader between the RESCO and Consumer)
- Third party Owned (Utility aggregates and acts as RESCO)

Apart from these combinations, aggregation of demand by the utility has also been explored as an option. This has resulted into two additional business models which are as follows -

- Consumer Owned (Utility only aggregates)
- Consumer Owned (Utility aggregates and acts as EPC)

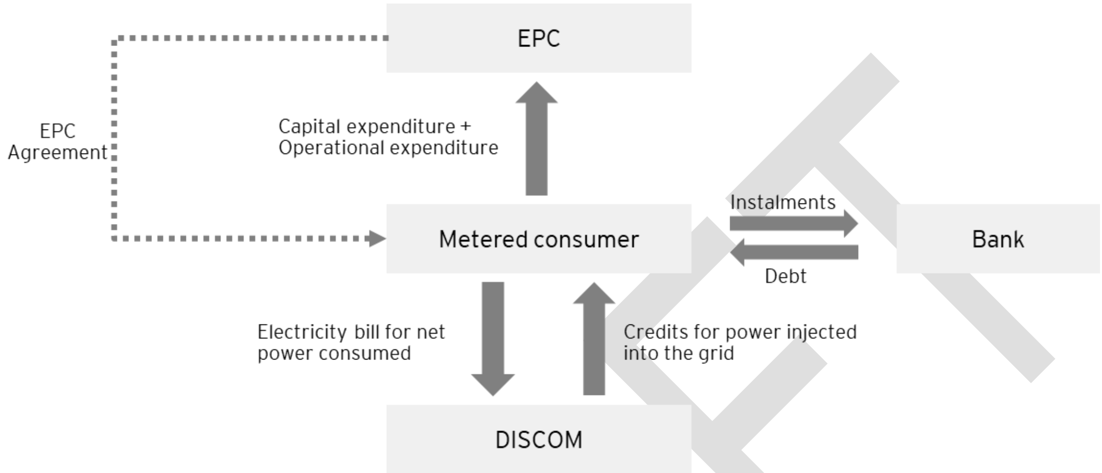
Detailed analysis of the six identified business models has been captured in the following section.

3. Consumer – centric models

1. Consumer owned model (CAPEX)

The consumer is responsible for the complete capital and operational expenditure for the rooftop solar plant. The consumer contracts an EPC firm to set up the plant at their premises. Based on the metering regulation, the commercial and energy settlement can be facilitated through either net or gross-metering arrangements.

Figure 1: Consumer owned model (CAPEX) - Money flow and Energy flow



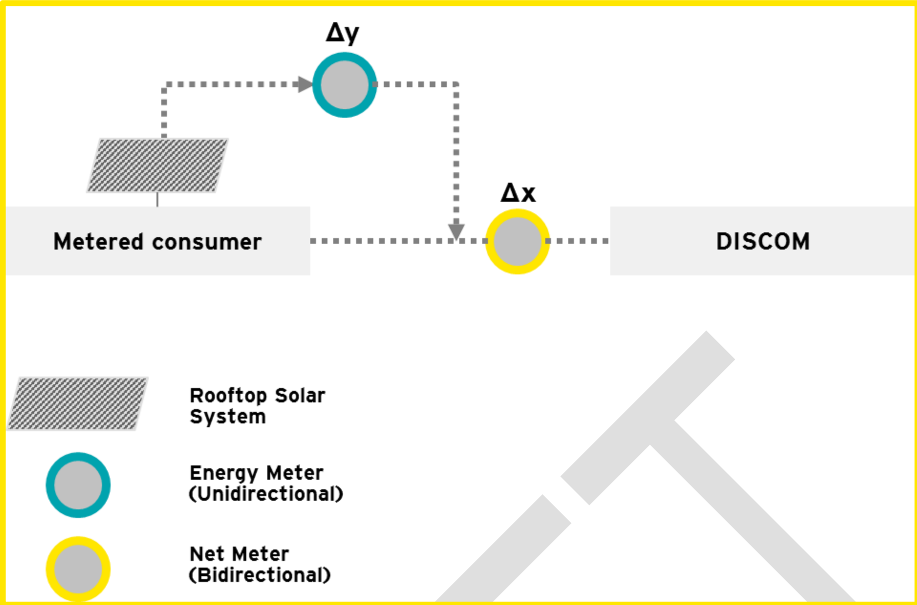
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely, net metering and net billing.

a. Net metering

Portion of the grid energy consumed by the site will be off-set by the energy generated by the rooftop solar plant. Net metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net – energy (units) consumed i.e. Total energy consumption – Total energy produced. The net metering mechanism utilises two meters, a bi-directional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustrative). **The utility bills the consumer based on the net meter reading**.

Figure 2: Energy flow under net metering - Consumer owned model (CAPEX)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of consumer - owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Number of units (kWh) consumed from the grid i.e. xn – (xn-1)

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows:

Electricity bill = Fixed charges + Δx*T

In case the net-generation in the billing period is greater than the total consumption, the Δx will be negative. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of Δx will be transferred as credits to the next month (subjective to state regulations).

The settlement and the cash flows have been described through the following cases:

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days

- Total consumption in the settlement period – 200 kWh
- Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
- Grid tariff – 10 INR / kWh

For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 2: Monthly cash flow under net metering for Consumer owned model (CAPEX)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to base case**
Utility	200 kWh X 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR	-	**Loss of INR 500 - 2000 = - INR 1500**
Consumer		200 kWh X 10 INR / kWh = 2000 INR	-	1. 50 kWh x 10 INR / kWh = 500 INR 2. Operation & maintenance expenditure (hereinafter referred to as OME)	**Savings of INR 2000 – (500 + OME)**

One-time expenditures / revenue

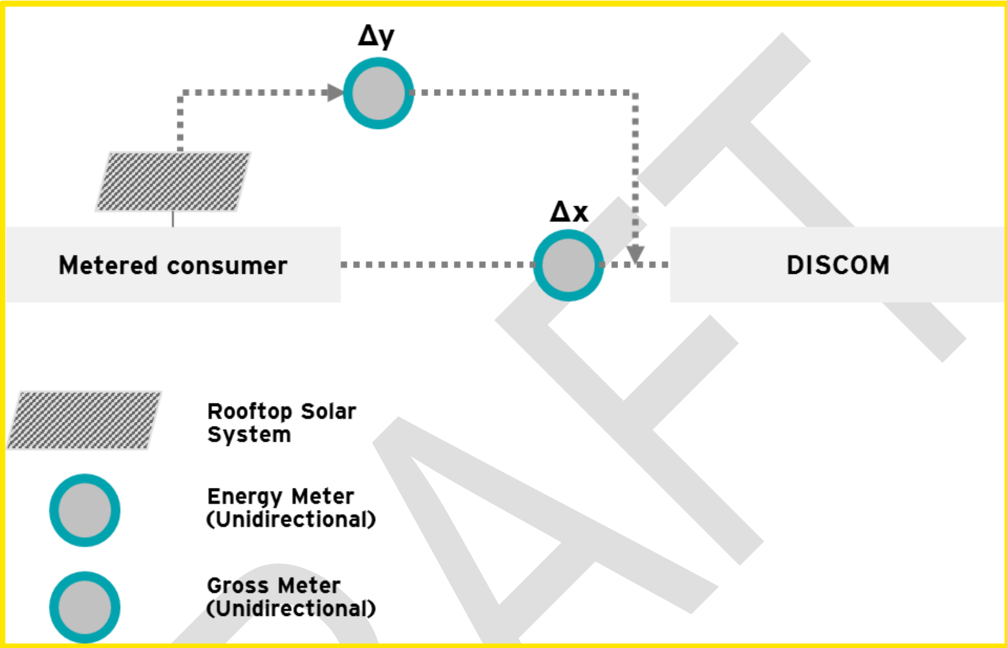
Table 3: One time expenditure/ revenue under net metering for Consumer owned model (CAPEX)

	Revenue	**Expenditure**
Consumer		EPC fees
EPC	EPC fees	

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through 2 unidirectional energy meters, one measuring the generation from the plant while the other measuring the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustrative).

Figure 3: Energy flow under net billing – Consumer owned model (CAPEX)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff.

Assuming that

- x_n – Gross meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n}$-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows:

Electricity bill = Fixed charges + Δx*T - Δy*T'

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case:

1. **Business as usual (hereinafter referred to as BAU)**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

   For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 4: Monthly cash flow under net billing for Consumer owned model (CAPEX)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	**Loss of INR (2000 – 1200) – 2000 = -1200 INR**
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	1. 200 kWh x 10 INR / kWh = 2000 INR 2. OME	**Savings of INR (1200 – 2000 – OME) + 2000 = INR 1200 – OME**

One-time expenditures / revenue

Table 5: One time expenditure/ revenue under net billing for Consumer owned model (CAPEX)

	Revenue	Expenditure
Consumer		EPC fees
EPC	EPC fees	

The consumer recovers the investment through:

1. Savings made by off-setting the grid consumption with the power produced by the rooftop solar plant (Net-metering).
2. Credits earned by injecting the excess generation into the grid. The credits can be utilised to offset the grid consumption of the site in that month.

Benefits:

1. Consumer completely owns the asset (rooftop solar system)

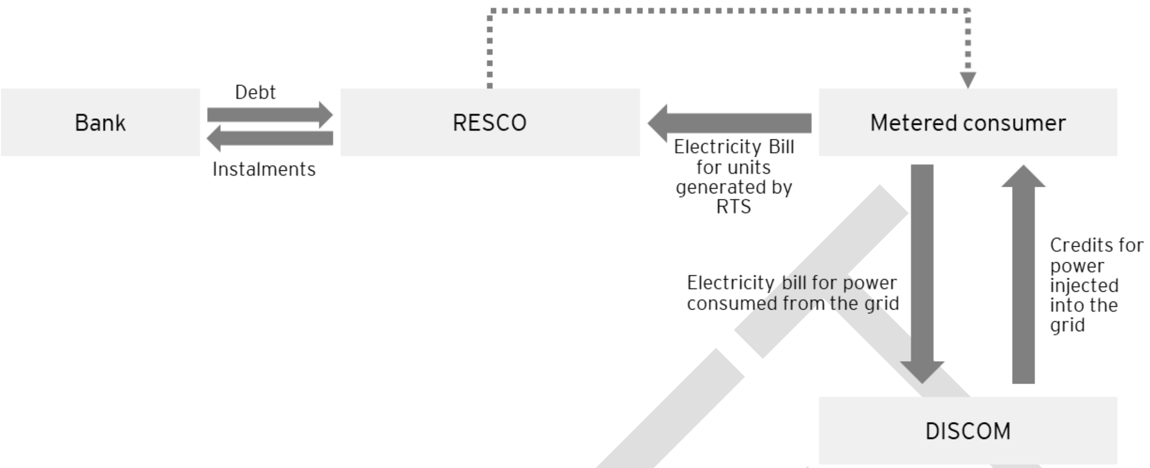
Dis-benefits:

1. Consumer faces an upfront capital expenditure
2. Operation and maintenance expenditure

2. Third-party owned model (RESCO)

A Renewable Energy Service Company or RESCO sets-up the rooftop solar system on the rooftop of the customer for no or low-cost. The RESCO, for its investment, gets a share of the savings being earned by the consumer by signing a PPA with the consumer.

Figure 4: Third party owned model (RESCO) – Money flow and Energy flow



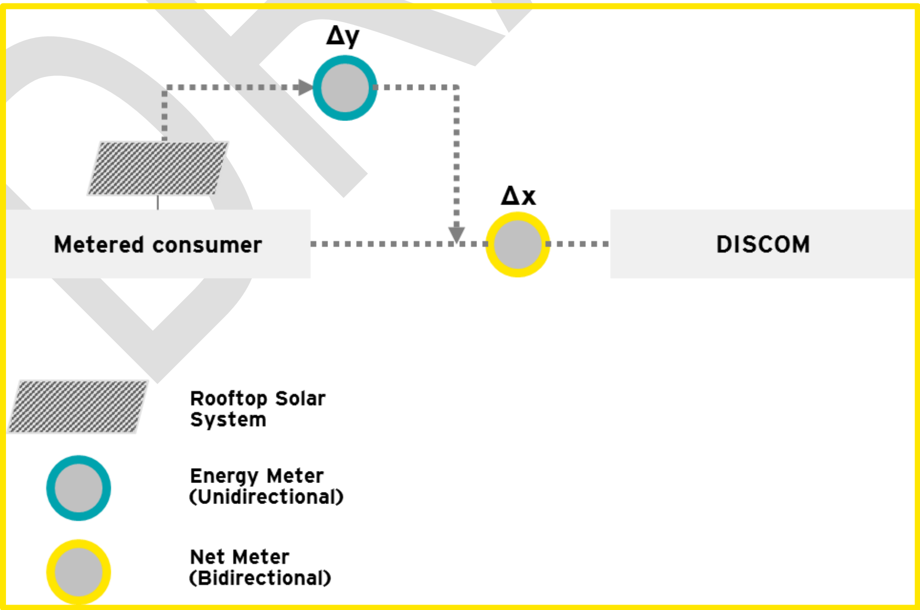
Commercial and energy settlement

Under this model, the financial and energy settlement can be performed through two modalities

a. Net metering

The commercial and the energy settlement between the consumer and the utility will be performed as in the consumer-owned model. The settlement between the consumer and the RESCO will be performed based on the signed PPA. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilised.

Figure 5: Energy flow under net metering - Third party owned model (RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the consumer and the RESCO is performed internally.

Assuming that

- xn – Net meter reading for month "n"
- yn – Energy meter reading for month "n"
- ∆x – Number of units (kWh) consumed from the grid i.e. xn – xn-1
- ∆y – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – PPA tariff

∆x is the value indicated by the net meter, while ∆y is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + ∆x*T
The consumer will pay the RESCO for the units generated by the rooftop solar system
Bill = ∆y*T', where T'<T

In case the net generation in the billing period is greater than the total consumption, the ∆x will hold a negative value. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of ∆x will be transferred as credits to the consumer for the next month (subjective to state regulations). The consumer will pay the RESCO for all the units generated rooftop solar system

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PPA tariff – 8 INR / kWh

   For the above assumptions, ∆x (net meter reading) will be 200 – 150 kWh = 50 kWh while ∆y (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 6: Monthly cash flow under net metering for Third party owned model (RESCO)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared with BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR	-	50 kWh x 10 INR / kWh = 500 INR	-	**Loss of INR 500 – 2000 = INR 1500**
Consumer	-	200 kWh x 10 INR / kWh = 2000 INR	-	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	**Savings of INR 2000 – (500 + 1200) = INR 300**
RESCO	-	-	150 kWh x 8 INR / kWh = 1200 INR	Operations and maintenance expenditure	**Savings of INR 1200 - OME**

One-time expenditures / revenue

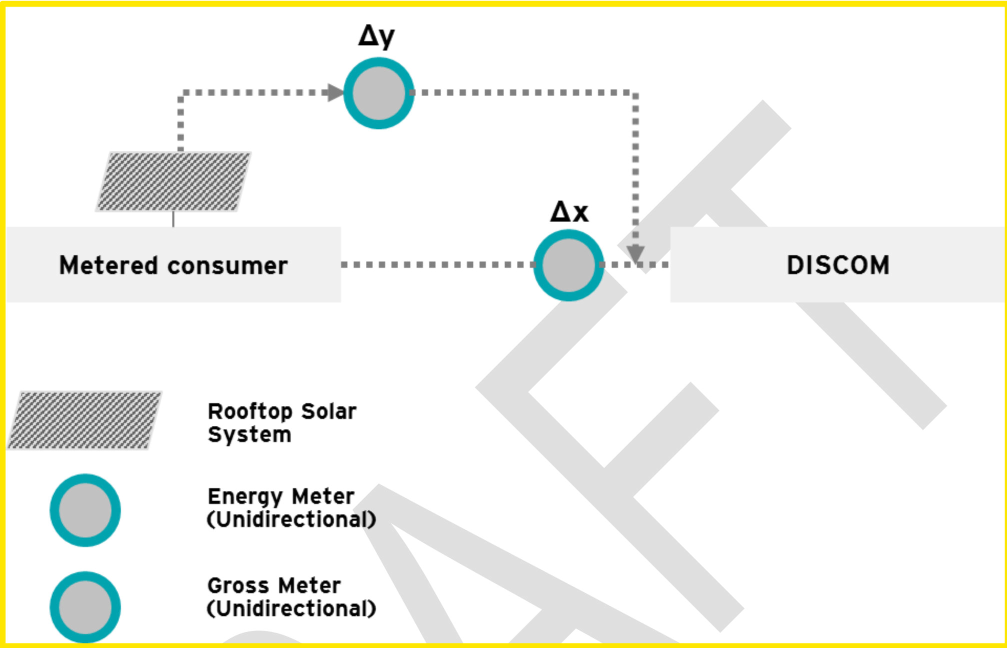
Table 7: One time expenditure/ revenue under net metering for Third party owned model (RESCO)

	Revenue	Expenditure
Consumer		
RESCO		EPC fees

b. Net billing

The energy and financial settlement between the consumer and the utility will be performed as in the consumer-owned model. The settlement between the consumer and the RESCO will be performed based on the signed PPA. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilised.

Figure 6: Energy flow under net billing - Third party owned model (RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the consumer and the RESCO is performed internally.

Assuming that
x_n – Gross meter reading for month "n"
y_n – Energy meter reading for month "n"
Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$
Δy – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T' – Net billing tariff
T'' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + Δx*T - Δy*T'

The settlement between Consumer and the RESCO is performed through a PPA, however in some cases roof rent may also be collected by the consumer from the RESCO. No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following cases

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh

   For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 8: Monthly cash flow under net billing for Third party owned model (RESCO)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared with BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	**Loss of INR – 2000 + (2000 – 1200) = INR 1200**
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	1. 200 kWh x 10 INR / kWh = 2000 INR 2. 150 kWh x 7 INR/ kWh = 1050 INR	**Savings of INR 2000 – (2000 – 1050) = INR 150**
RESCO			150 kWh x 7 INR/ kWh = 1050 INR	Operations and maintenance expenditure	**Revenue of INR 1050 - OME**

One-time expenditures / revenue

Table 9: One time expenditure/ revenue under net billing for Third party owned model (RESCO)

	Revenue	Expenditure
Consumer		
RESCO		EPC fees

Benefits:
1. No upfront capital expenditure for the consumer
2. Operation and maintenance is performed by the RESCO

Dis-benefits:
1. Payment default risk exists for the RESCO

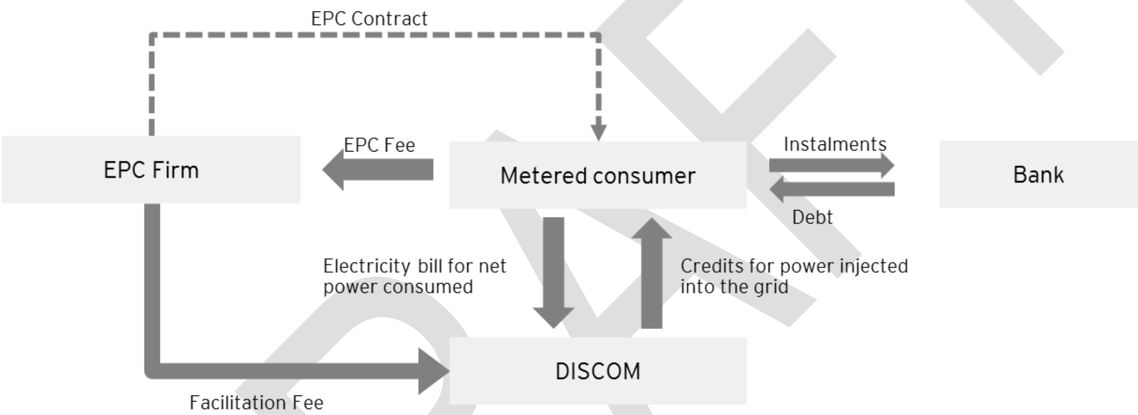
4. Utility-centric models

1. Consumer owned model (utility only aggregates)

The utility acts as an aggregator by identifying the demand for rooftop solar in its distribution circle. The demand can be identified through a single-window portal on the utility website or through other sources. The consumers willing to install rooftop solar will have to contact just the utility for installation. Once the demand has been aggregated, the utility will initiate a reverse bidding to provide EPC services to the aggregated demand. Only EPC service providers empanelled by the utility will be permitted to participate in the reverse bidding. The successful EPC service provider will sign EPC contracts with the interested consumers. The utility will charge a facilitation fee from the successful bidder for aggregating the demand and thereby decreasing the transaction cost spent by EPC providers for lead generation. The utility will also sign a project management services agreement with the consumers for monitoring the project till interconnection with the grid. The consumer will be responsible for the complete capital expenditure.

The commercial and energy settlement remain similar to the consumer owned model (business model 1).

Figure 7: Consumer owned model (Utility only aggregates) – Money flow and Energy flow



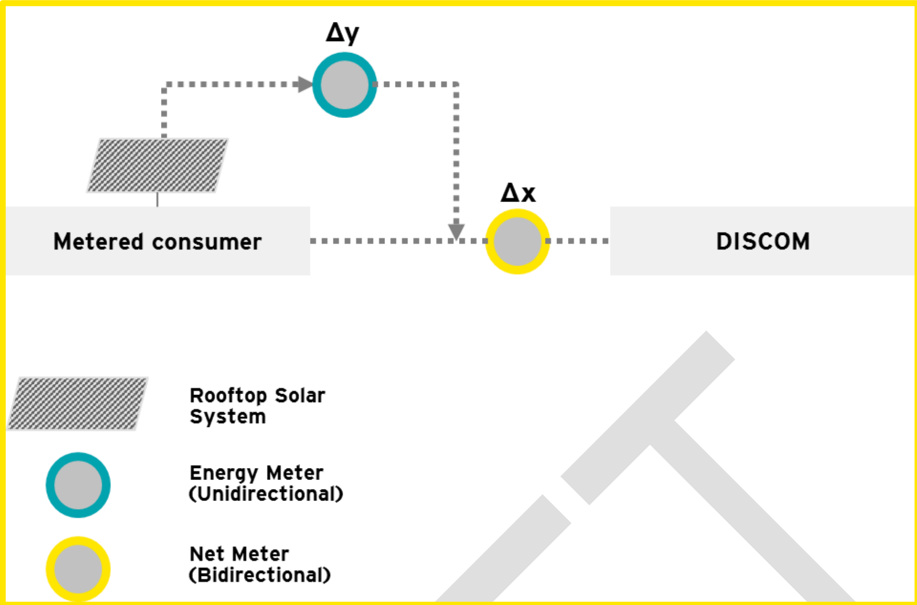
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely net metering and net billing.

a. Net metering

Portion of the grid energy consumed by the site will be off-set by the energy generated by the rooftop solar plant. Net-metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net – energy (units) consumed i.e. Total energy consumption – Total energy produced. The net – metering mechanism utilises two meters, a bi-directional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustrative). **The utility bills the consumer based on the net meter reading**.

Figure 8: Energy flow under net metering - Consumer owned model (Utility only aggregates)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of consumer - owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month “n”

yn – Energy meter reading for month “n”

∆x – Number of units (kWh) consumed from the grid i.e. xn – xn-1

∆y – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

∆x is the value indicated by the net meter, while ∆y is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows

Electricity bill = Fixed charges + ∆x*T

In case the net-generation in the billing period is greater than the total consumption, the ∆x will be negative. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of ∆x will be transferred as credits to the next month (subjective to state regulations).

The settlement and the cash flows have been described through the following cases -

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days

- Total consumption in the settlement period – 200 kWh
- Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
- Grid tariff – 10 INR / kWh

For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 10: Monthly Cash flow under net metering for Consumer owned model (Utility only aggregates)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to base case**
Utility	200 kWh X 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR	-	**Loss of INR 500 - 2000 = - INR 1500**
Consumer		200 kWh X 10 INR / kWh = 2000 INR	-	1. 50 kWh x 10 INR / kWh = 500 INR 2. Operation & maintenance expenditure (hereinafter referred to as OME)	**Savings of INR 2000 – (500 + OME)**

One-time expenditures / revenue

Table 11: One time expenditure/ revenue under net metering for Consumer owned model (Utility only aggregates)

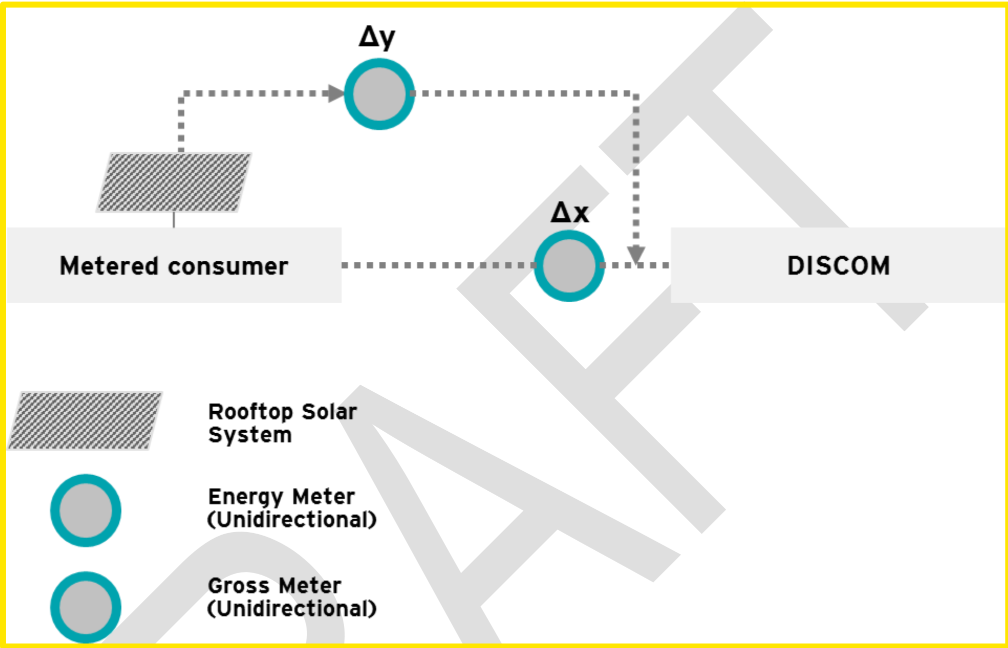
	Revenue	Expenditure
Consumer		EPC fees
EPC	EPC fees	Facilitation fees

Utility	Facilitation fees	

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through 2 unidirectional energy meters, one measuring the generation from the plant while the other measuring the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustrative).

Figure 9: Energy flow under net billing - Consumer owned model (Utility only aggregates)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff

Assuming that

xn – Gross meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows

Electricity bill = Fixed charges + Δx*T - Δy*T'

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

   For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 12: Monthly cash flow under net billing for Consumer owned model (Utility only aggregates)

	Case 1 (BAU)		**Case 2**		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	**Loss of INR (2000 – 1200) – 2000 = - 1200 INR**
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	3. 200 kWh x 10 INR / kWh = 2000 INR 4. OME	**Savings of INR (1200 – 2000 – OME) + 2000 = INR 1200 – OME**

One-time expenditures / revenue

Table 13: One time expenditure/ revenue under net billing for Consumer owned model (Utility only aggregates)

	Revenue	**Expenditure**
Consumer		EPC fees
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees	

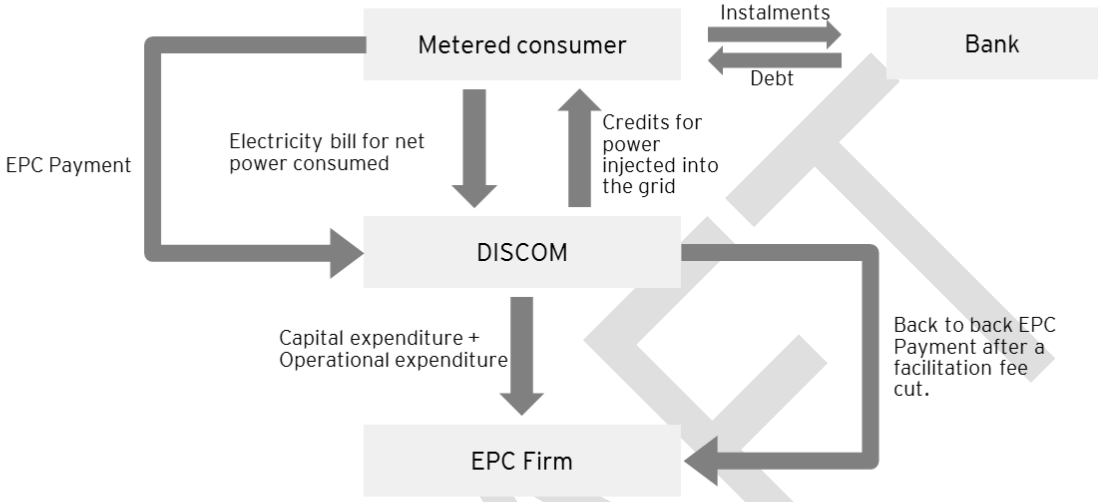
Benefits:
1. Single-window portal for the consumer for installation of rooftop solar
2. Reduced EPC costs due to economies of scale and competition amongst EPC providers
3. Streamlined interconnection process due to continued involvement of the utility through the installation stage
4. Verified quality of the installed systems due to setting up of procurement standards
5. Reduced financing costs due to lower risks

Dis-benefits:
1. Upfront capital expenditure is required from the consumer
2. Payment default risk for the lender

2. Consumer Owned (Utility aggregates and acts as EPC)

The model is similar to the previous model except that the EPC contract for the installation of the rooftop solar plants is signed between the consumer and the utility. The utility further signs back-to-back agreement with the successful EPC player identified through reverse bidding. The payment for the EPC services is paid to the utility, which further transfers the fee to the EPC services firm on a margin. The back-to-back agreements provides payment security to the service provider while ensuring better services to the consumer. The utility earns revenue in the form of a one-time facilitation fee and a margin on the back-to-back EPC agreements.

Figure 10: Consumer Owned (Utility aggregates and acts as EPC) – Money flow and Energy Flow



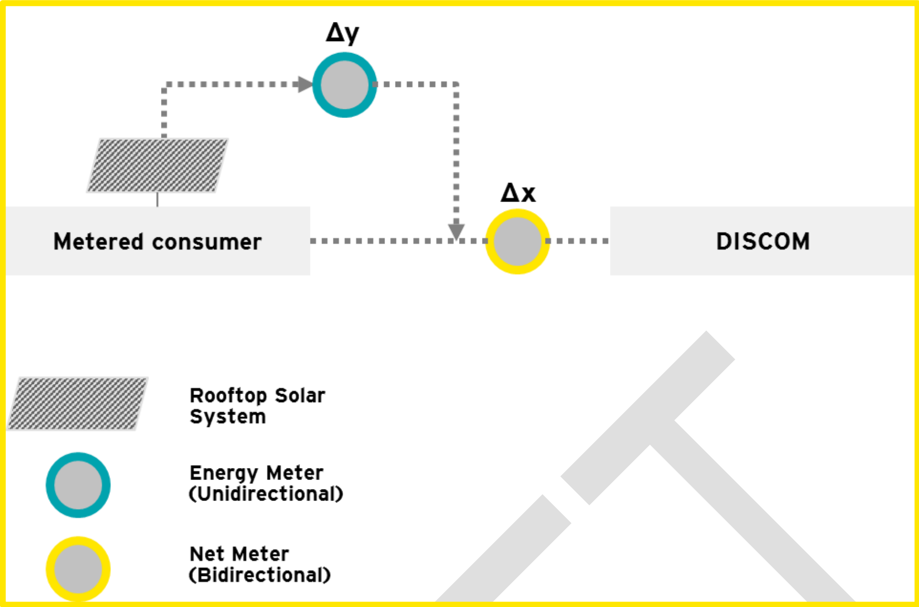
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely net metering and net billing.

a. Net metering

Portion of the grid energy consumed by the site will be off-set by the energy generated by the rooftop solar plant. Net-metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net – energy (units) consumed i.e. Total energy consumption – Total energy produced. The net – metering mechanism utilises two meters, a bi-directional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustrative). **The utility bills the consumer based on the net meter reading**.

Figure 11: Energy flow under net metering – Consumer Owned (Utility aggregates and acts as EPC)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of consumer - owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

∆x – Number of units (kWh) consumed from the grid i.e. xn – xn-1

∆y – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

∆x is the value indicated by the net meter, while ∆y is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows

Electricity bill = Fixed charges + ∆x*T

In case the net-generation in the billing period is greater than the total consumption, the ∆x will be negative. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of ∆x will be transferred as credits to the next month (subjective to state regulations).

The settlement and the cash flows have been described through the following cases -

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days

- Total consumption in the settlement period – 200 kWh
- Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
- Grid tariff – 10 INR / kWh

For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 14: Monthly cash flow under net metering for Consumer Owned (Utility aggregates and acts as EPC)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to base case**
Utility	200 kWh X 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR	-	**Loss of INR 500 - 2000 = - INR 1500**
Consumer		200 kWh X 10 INR / kWh = 2000 INR	-	3. 50 kWh x 10 INR / kWh = 500 INR 4. Operation & maintenance expenditure (hereinafter referred to as OME)	**Savings of INR 2000 – (500 + OME)**

One-time expenditures / revenue

Table 15: One time expenditure/ revenue under net metering for Consumer Owned (Utility aggregates and acts as EPC)

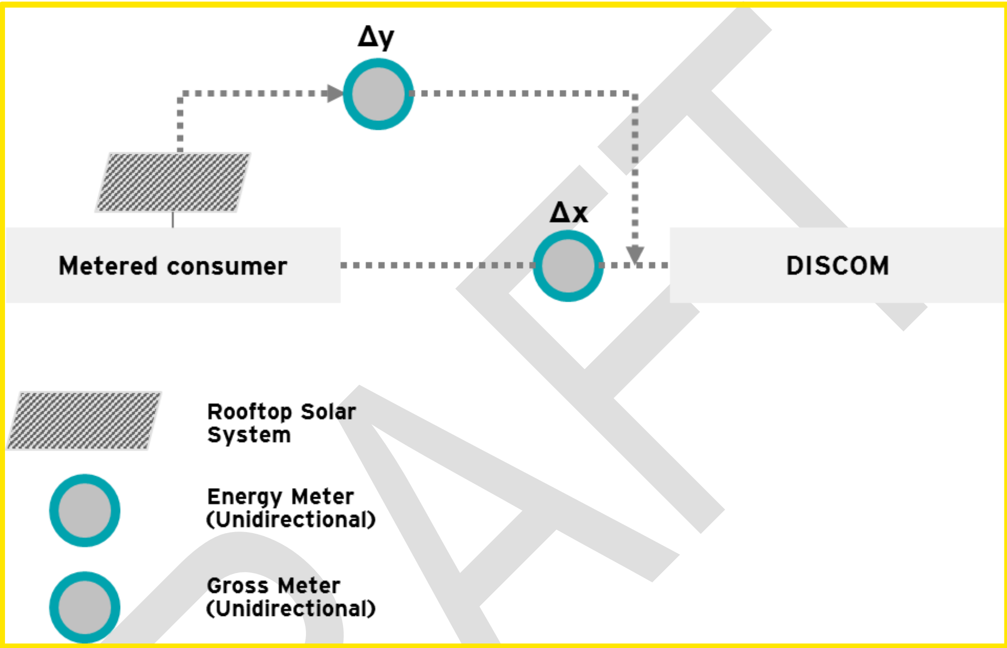
	Revenue	Expenditure
Consumer		EPC fees + EPC fees margin
EPC	EPC fees	Facilitation fees

Utility	Facilitation fees + EPC fees margin	

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through 2 unidirectional energy meters, one measuring the generation from the plant while the other measuring the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustrative).

Figure 12: Energy flow under net billing – Consumer Owned (Utility aggregates and acts as EPC)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff

Assuming that

xn – Gross meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows

Electricity bill = Fixed charges + $\Delta x \cdot T - \Delta y \cdot T'$

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions

   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions

   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

   For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 16: Monthly cash flow under net billing for Consumer Owned (Utility aggregates and acts as EPC)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	**Loss of INR (2000 – 1200) – 2000 = - 1200 INR**
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	5. 200 kWh x 10 INR / kWh = 2000 INR 6. OME	**Savings of INR (1200 – 2000 – OME) + 2000 = INR 1200 – OME**

One-time expenditures / revenue

Table 17: One time expenditure/ revenue under net billing Consumer Owned (Utility aggregates and acts as EPC)

	Revenue	Expenditure
Consumer		EPC fees + EPC fees margin
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees + EPC fees margin	

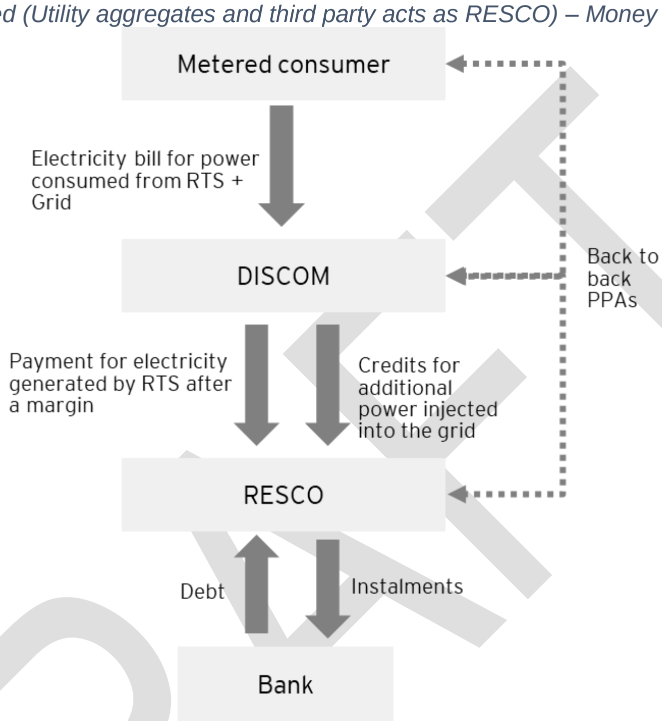
Benefits
1. Single-window portal for the consumer for installation of rooftop solar
2. Improved service experience for the consumer due to project management by the utility
3. Reduced EPC costs due to economies of scale and competition amongst EPC providers
4. Streamlined interconnection process due to continued involvement of the utility through the installation stage
5. Verified quality of the installed systems due to setting up of procurement standards
6. Securitised payments to the EPC providers
7. Reduced financing costs due to lower risks

Dis-benefits:
1. Upfront capital expenditure is required from the consumer.
2. Payment default risk for the lender

3. Third party owned (Utility aggregates and acts as trader)

Under this model, the utility does not set up, own or operate any rooftop solar plant. The utility aggregates the demand in its distribution circle. A RESCO, selected based on reverse bidding, invests in the asset. For securitising the payments to the RESCO from the consumer, the payment is routed through the utility. The utility signs a PPA with the RESCO and purchases all the energy generated by the rooftop solar plant at a pre-determined tariff mentioned in the PPA. The utility further signs a PSA with the consumer for sale of all the generated power. The utility adds a trading fees or a facilitating fees for aggregating the demand and ensuring the payment security on the electricity purchased from the RESCO.

Figure 13: Third party owned (Utility aggregates and third party acts as RESCO) – Money flow and Energy flow



Benefits:

1. Single-window portal for the consumer for installation of rooftop solar (including finance).
2. Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs.
3. Securitised payments to the financiers and the RESCO.
4. Reduced financing costs due to lower risks.

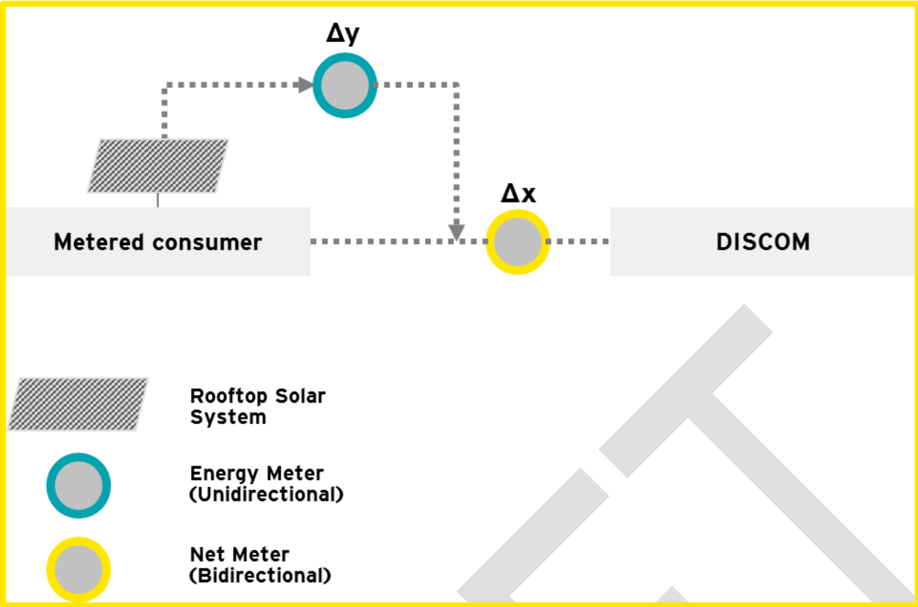
Commercial and energy settlement

Under this model, the commercial and the energy settlement can be performed through both, net and net billing.

a. Net metering

Settlement will be performed between RESCO and the utility, and the utility and the consumer. The settlement between the utility and the RESCO will be performed based on the signed PPA. The utility will pay the RESCO for all the energy generated by the rooftop solar system at a tariff mentioned in the PPA. The metering will be done similar to the conventional net metering as described below in the illustrative.

Figure 14: Energy flow under net metering – Third party owned (Utility aggregates and third party acts as RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the utility and the RESCO is performed based on the signed PPA.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

∆x – Number of units (kWh) consumed from the grid i.e. xn – xn-1

∆y – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – PPA tariff

T'' – PSA tariff

T'' – T' – Utility's trading margin

∆x is the value indicated by the net meter, while ∆y is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as the follows

Electricity bill = Fixed charges + ∆x*T + ∆y*T''

The utility will pay the RESCO for the units generated by the rooftop solar system

Bill = ∆y*T', where T'<T

In case the net generation in the billing period is greater than the total consumption, the ∆x will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and the energy generated by the rooftop solar plant, while the absolute value of ∆x will be transferred as credits to the consumer for the next month (subjective to state regulations).

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions

- No rooftop solar installation
- Total consumption in the billing period – 200 kWh
- Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions

   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PSA tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh
   - Utility trading margin – 1 INR / kWh

   For the above assumptions, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Figure 15: Monthly cash flow under net metering for Third party owned (Utility aggregates and third party acts as RESCO)

	Case 1 (BAU)		**Case 2**		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to base case**
Utility	200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	150 kWh x 7 INR / kWh = 1050 INR	**Loss of INR (1200 + 500 – 1050) - 2000 = - 1350**
Consumer		200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	**Savings of INR 2000 – 1700 = 300**
RESCO			150 kWh x 7 INR / kWh = 1050 INR	OME	**Revenue of INR 1050 - OME**

One-time expenditures / revenue

Table 18: One time expenditure/ revenue under net metering for Third party owned (Utility aggregates and third party acts as RESCO)

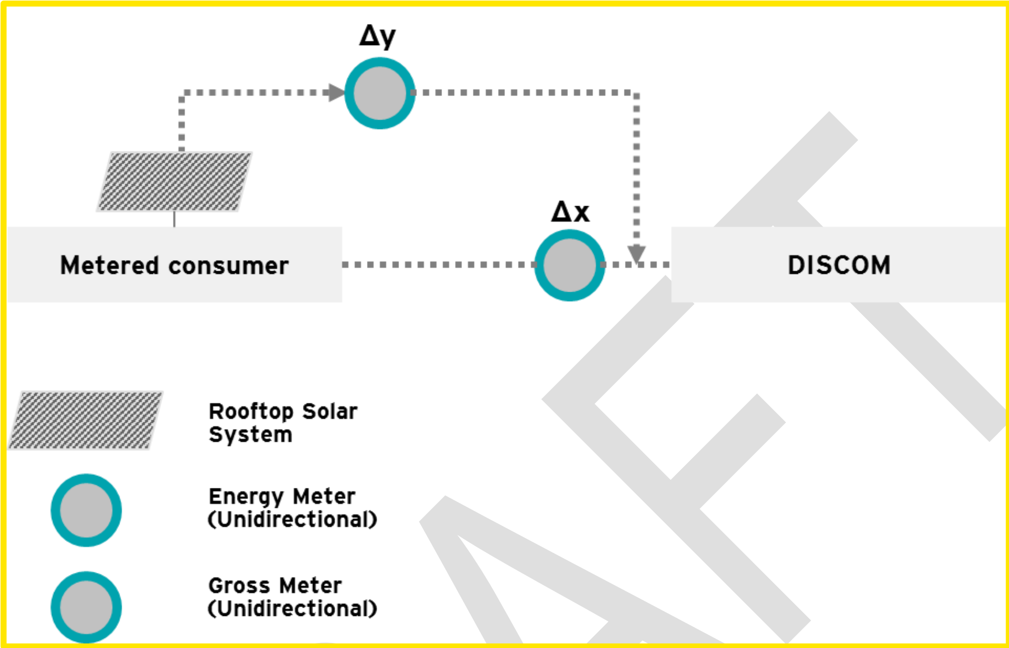
	Revenue	Expenditure
Utility	Facilitation Fee	

Consumer		
RESCO		EPC fees + Facilitation Fee

b. Net billing

Settlement will be performed between RESCO and the utility, and the utility and the consumer. The settlement between the utility and the RESCO will be performed based on the signed PPA. The utility will pay the RESCO for all the energy generated by the rooftop solar system at a tariff mentioned in the PPA. The metering will be done similar to the conventional net billing as described below in the illustrative.

Figure 16: Energy flow under net billing – Third party owned (Utility aggregates and third party acts as RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the utility and the RESCO is performed based on the signed PPA.

Assuming that
xn – Gross meter reading for month “n”
yn – Energy meter reading for month “n”
Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1
Δy – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T’ – PPA tariff
T’’ – PSA tariff
T’’ – T’ – Utility’s trading margin

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + Δx*T - Δy*T’’

The utility will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T’, where T’<T

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PSA tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh
   - Utility trading margin – 1 INR / kWh

   For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 19: Monthly cash flow under net billing for Third party owned (Utility aggregates and third party acts as RESCO)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared to base case**
Utility	200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	150 kWh x 7 INR / kWh = 1050 INR	**Loss of INR (1200 + 500 – 1050) - 2000 = - 1350**
Consumer		200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	**Savings of INR 2000 – 1700 = 300**
RESCO			150 kWh x 7 INR / kWh = 1050 INR	OME	**Revenue of INR 1050 - OME**

One-time expenditures / revenue

Table 20: One time expenditure/ revenue under net billing for Third party owned (Utility aggregates and third party acts as RESCO)

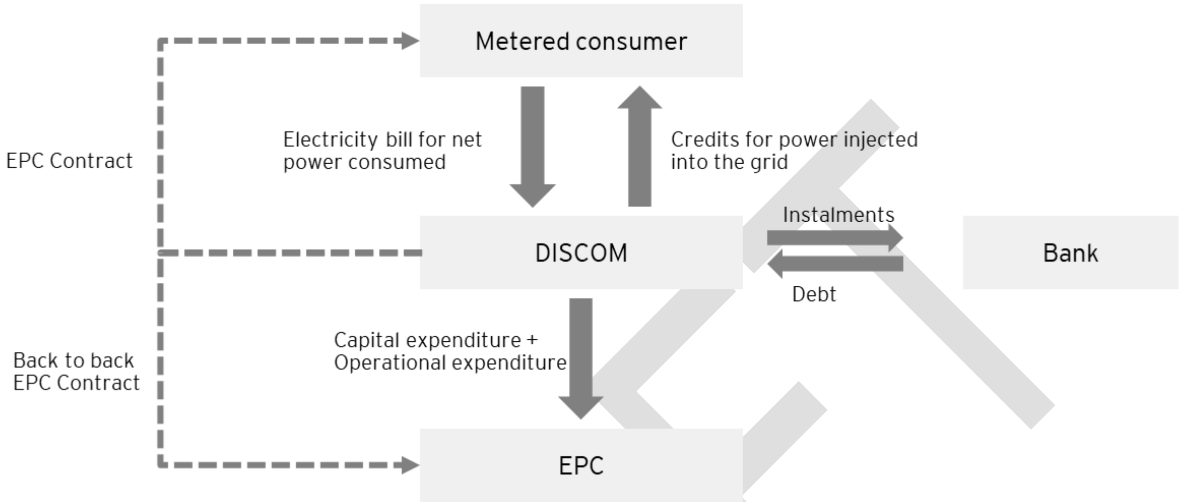
	Revenue	Expenditure
Utility	Facilitation Fee	
Consumer		

RESCO		EPC fees + Facilitation Fee

4. Third party owned (Utility aggregates and acts as RESCO)

The utility acts as an aggregator and aggregates the demand as in case of the aggregator model. It also raises debt for acting as a RESCO for the aggregated demand and installs the rooftop solar systems at the premises of the consumers. The utility in this model sets up, owns and operates the rooftop solar plant. PPAs are signed between the utility and the consumers. The utility may subcontract the EPC and the O&M components. It collects the charges for the electricity consumed from the grid and the rooftop solar plants through the monthly bill.

Figure 17: Third party owned (Utility aggregates and acts as RESCO) – Money flow and Energy flow



Benefits:

1. Single-window portal for the consumer for installation of rooftop solar (including finance)
2. Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs
3. Securitised payments to the financiers
4. Reduced financing costs due to lower risks

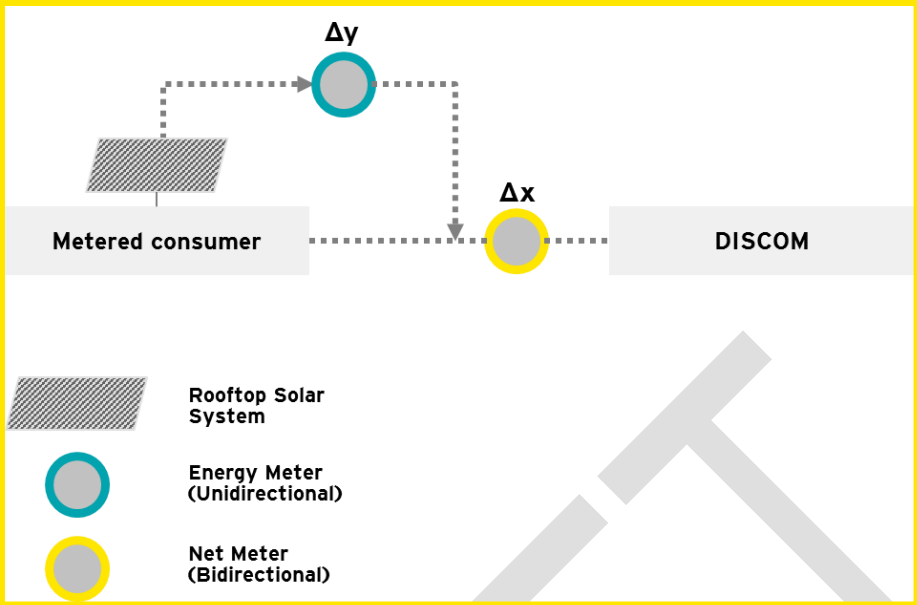
Commercial and energy settlement

Under this model, the financial and energy settlement can be performed through both, net metering and net billing.

a. Net metering

The commercial and the energy settlement between the consumer and the utility will be performed as in the consumer-owned model, except that the utility is the RESCO in this case. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilised.

Figure 18: Energy flow under net metering – Third party owned (Utility aggregates and acts as RESCO)



Settlement modality

The commercial settlement is performed between two stakeholders i.e. the consumer and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill.

Assuming that

xn – Net meter reading for month "n"
yn – Energy meter reading for month "n"
∆x – Number of units (kWh) consumed from the grid i.e. xn – xn-1
∆y – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T' – PPA tariff

∆x is the value indicated by the net meter, while ∆y is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + ∆x*T + ∆y*T'

In case the net generation in the billing period is greater than the total consumption, the ∆x will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and the ∆y*T', while the absolute value of ∆x will be transferred as credits to the consumer for the next month (subjective to state regulations).

The settlement and the cash flows have been described through the following case

1. **Business as usual (hereinafter referred to as BAU)**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System Capacity – 1 kW

- Number of units generated per day – 5 kWh
- Settlement period – 30 days
- Total consumption in the settlement period – 200 kWh
- Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
- Grid tariff – 10 INR / kWh
- PPA tariff – 8 INR / kWh

For the above assumptions, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 21: Monthly cash flow under net metering for Third party owned (Utility aggregates and acts as RESCO)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared with BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR	-	**1.** 50 kWh x 10 INR / kWh = 500 INR **2.** 150 kWh x 8 INR / kWh = 1200 INR	OME	**Loss of INR (500 + 1200 – OME) – 2000 = - (OME + 300)**
Consumer	-	200 kWh x 10 INR / kWh = 2000 INR	-	**1.** 50 kWh x 10 INR / kWh = 500 INR **2.** 150 kWh x 8 INR / kWh = 1200 INR	**Savings of INR 2000 – (500 + 1200) = INR 300**

One-time expenditures / revenue

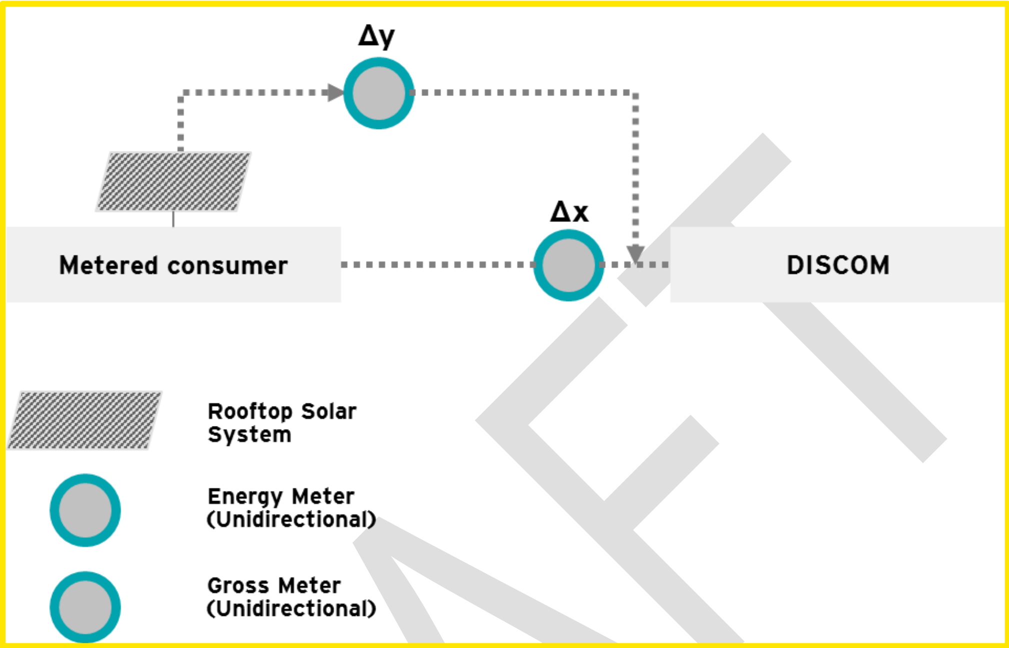
Table 22: One time expenditure/ revenue under net metering for Third party owned (Utility aggregates and acts as RESCO)

	Revenue	Expenditure
Consumer		
Utility		EPC fees

b. Net billing

The energy and financial settlement between the consumer and the utility will be performed as in the consumer-owned model The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilised.

Figure 19: Energy flow under net billing – Third party owned (Utility aggregates and acts as RESCO)



Settlement modality

The commercial settlement is performed between the consumer and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill.

Assuming that
x_n – Gross meter reading for month "n"
y_n – Energy meter reading for month "n"
Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$
Δy – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + $(\Delta x - \Delta y)*T + \Delta y*T'$

The settlement and the cash flows have been described through the following cases

1. **Business as usual (hereinafter referred to as BAU)**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

Assumptions

- System Capacity – 1 kW
- Number of units generated per day – 5 kWh
- Settlement period – 30 days
- Total consumption in the settlement period – 200 kWh
- Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
- Grid tariff – 10 INR / kWh
- PPA tariff – 8 INR / kWh

For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 23: Monthly cash flow under net billing for Third party owned (Utility aggregates and acts as RESCO)

	Case 1 (BAU)		Case 2		
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**	**Profit / loss as compared with BAU**
Utility	200 kWh x 10 INR / kWh = 2000 INR		**1.** 50 kWh x 10 INR / kWh = 500 INR **2.** 150 kWh x 8 INR / kWh = 1200 INR	OME	**Loss of INR (500 + 1200 – OME) – 2000 = - (OME + 300)**
Consumer		200 kWh x 10 INR / kWh = 2000 INR	-	**1.** 50 kWh x 10 INR / kWh = 500 INR **2.** 150 kWh x 8 INR / kWh = 1200 INR	**Savings of INR 2000 – (500 + 1200) = INR 300**

One-time expenditures / revenue

Table 24: One time expenditure/ revenue under net billing for Third party owned (Utility aggregates and acts as RESCO)

	Revenue	Expenditure
Consumer		
Utility		EPC fees

5. Benefit analysis

Table 25: Legends for Benefit analysis

Legend	
T	Grid tariff
T'	Discovered tariff
m	Total consumption (number of units)
n	Number of units of electricity consumed from the Rooftop Solar System

Table 26: Summary of benefits of proposed business models

S. No	Model	Utility	Consumer	Developer
1	Consumer-owned model (CAPEX)	Loss of energy sale due to influx of rooftop solar	EPC fees	Profit on EPC fee received
			n*T	
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill. Gains the asset	Gains revenue as EPC fee
2	Third-party owned (RESCO) model	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC fees
				n*T'
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill.	Gains the Asset
3	Consumer owned model (utility only aggregates)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC fee received
		Loss of energy sale due to influx of rooftop solar	n*T	Facilitation fees (assuming 2-3% of the total investment)

Suggested business models and their impact on utilities

S. No	Model	Utility	Consumer	Developer
	Overall	Utility loses consumer but makes revenue on facilitation fees	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current regulations.	Gains revenue as EPC fee and Saves on marketing cost.
4	Consumer Owned (Utility aggregates and acts as EPC)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC Fee (after a margin cut)
		p% on back to back agreements	n*T	p% on back to back agreements
		Loss of energy sale due to influx of rooftop solar		Facilitation fees (assuming 2-3% of the total investment)
	Overall	Utility loses consumer but makes revenue on facilitation fee for aggregation and margin on back to back EPC contract.	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current regulations.	Gains revenue on EPC. Although loses margin, saves on marketing cost and gains payment security.
5	Third Party owned (Utility aggregates and third party acts as RESCO)	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC Fee
		Facilitation fees (assuming 2-3% of the total investment)		Facilitation fees (assuming 2-3% of the total investment)
		p% on all units of energy traded		p% on all units of energy traded
				Revenues from energy sale
	Overall	Utility makes revenues due to energy trading and facilitation fees for aggregation	RESCO model beneficial due to no capital investment	Revenues due to energy sale and cheaper finance due to payment security. Low transaction costs and lower capital cost due to aggregated demand. Also, gains the asset.
6	Third party owned (Utility aggregates and acts as RESCO)	EPC Fee	n(T-T')	
		Revenue from energy sale (y*n)		
	Overall	Utility makes revenue on energy sale to the consumers. Lower cost of procurement due to economies of scale.	RESCO beneficial due to no capital investment	Developer plays no role

6. Analysing Feasibility of Business Models

Case Study 1 – Jharkhand - Jharkhand Bijli Vitran Nigam Limited

The commercial impact of rooftop solar penetration on the revenues of the DISCOM were assessed by developing an analytical model capturing the actual revenue loss due to rooftop solar and the benefits due to RPO, reduced procurement and reduced losses.

The inputs to the model were as follows –

- Existing DISCOM tariffs across consumer segments
- Energy sales annual escalation (assumption)
- Net metering / gross metering tariff
- Annual rate of rooftop solar penetration (assumption)
- Average cost of supply and annual escalation (assumption)
- Distribution loss and annual escalation (assumption)
- APPC and annual escalation (assumption)
- RPO targets and RPO deficit
- Solar EPC costs and other financials

The outputs to the model were as follows –

- Loss incurred by the DISCOM over the next 25 years due to reduced energy sales
- Benefits accrued due to RPOs and reduced losses
- Actual loss incurred by the DISCOM
- Benefits accrued due to each of the business models

MNRE targets for rooftop solar in Jharkhand have been considered as the penetration scenario for calculation. The key highlights of the study were as follows –

- The NPV of total revenue loss due to rooftop solar over the next 25 years is INR 2,885 crores. However the total benefits due to RPOs met, decreased procurement and reduced losses are around INR 2,400 crores. Therefore the actual loss over the next 25 years is only INR 486 crores. **The actual loss is ~15% of the perceived revenue loss**.

- In the additional scenarios, utility centric business models such as the following were considered
  - Utility aggregation
  - Utility aggregation and acting as EPC
  - Utility as a trader
  - Utility as a RESCO

- For each of the utility centric business models, the actual loss is reduced further due to an additional revenue stream. However, only “Utility as a RESCO” business model returns a profit or a no-profit-no-loss scenario. Sensitivity analysis was utilised to determine the PPA tariff for the utility for a no-profit-no-loss scenario under the “Utility as a RESCO” business model. For JBVNL, the PPA tariff was determined to be in the range of 5.74 – 5.75 INR/kWh.

Case Study 2 – Delhi – BSES Yamuna Power Limited

The commercial impact of rooftop solar penetration on the revenues of the DISCOM were assessed by developing an analytical model capturing the actual revenue loss due to rooftop solar and the benefits due to RPO, reduced procurement and reduced losses.

The inputs to the model were as follows –

- Existing DISCOM tariffs across consumer segments
- Energy sales annual escalation (assumption)
- Net metering / gross metering tariff
- Annual rate of rooftop solar penetration (assumption)
- Average cost of supply and annual escalation (assumption)
- Distribution loss and annual escalation (assumption)
- APPC and annual escalation (assumption)
- RPO targets and RPO deficit
- Solar EPC costs and other financials

The outputs to the model were as follows –

- Loss incurred by the DISCOM over the next 25 years due to reduced energy sales
- Benefits accrued due to RPOs and reduced losses
- Actual loss incurred by the DISCOM
- Benefits accrued due to each of the business models

MNRE targets for rooftop solar in Delhi have been considered as the penetration scenario for calculation. The key highlights of the study were as follows –

- The NPV of total revenue loss due to rooftop solar over the next 25 years is INR 7,773 crores. However the total benefits due to RPOs met, decreased procurement and reduced losses are around INR 2,400 crores. Therefore the actual loss over the next 25 years is only INR 2,026 crores. **The actual loss is ~25% of the perceived revenue loss**.

- In the additional scenarios, utility centric business models such as the following were considered
    - Utility aggregation
    - Utility aggregation and acting as EPC
    - Utility as a trader
    - Utility as a RESCO

- For each of the utility centric business models, the actual loss is reduced further due to an additional revenue stream. However, only "Utility as a RESCO" business model returns a profit or a no-profit-no-loss scenario. Sensitivity analysis was utilised to determine the PPA tariff for the utility for a no-profit-no-loss scenario under the "Utility as a RESCO" business model. For BYPL, the PPA tariff was determined to be in the range of 7.4 – 7.5 INR/kWh. The PPA tariff is higher in Delhi as compared with Jharkhand due to higher retail tariffs and lower AT&C losses in Delhi. The "Utility as a RESCO" model will be financially feasible on in the case of commercial consumer segment.

KPMG

Annexure-V

Electricity Regulatory Management System (ERMS)

Implementation for West Bengal Electricity Regulatory Commission (WBERC)

Presentation to FOR

(Forum of Regulators)

24-August, 2018

Agenda

- ❑ Challenges for Regulatory Commission
- ❑ Solution to the challenges
- ❑ ERMS Solution Vision
- ❑ Fuel Cost Determination Example
- ❑ Power Purchase Cost Determination Example
- ❑ Prototype Demonstration
- ❑ Appendices
  - Functional Modules in ERMS
  - Typical Regulatory Process
  - Value Adds
    - Petition Filing Process
    - Petition Data Validation Process – Value Adds
    - Internal Computation Process

Challenges for Regulatory Commissions

- How to verify the authenticity of the derived data
- How to exercise a systematic due diligence on those derived data set to ensure consistency across related parameters
- How to derive appropriate norms where all computations happen on engineered data sets
- Is there a way to find out if impact of inefficiency or errors are not passed on to consumers
- How to make projections on any technical parameter
- How to standardize the process of analysis and additional data requirement

Solution to the challenges

- Capturing granular data at source, a comprehensive set of un-engineered data
- Applying validation logic in a systematic way to check if aggregating granular data results into matching the derived data
- Applying correlation across related parameters to check if their trend is following the rule at monthly or further granular level
- The raw data set over a period of time helps in practical insights and thus enable sustainable norms derivation
- Granular data across technical parameters over a period of time enable identifying any anomalous behavior – thus enables further investigation on certain data points
- Various statistical models enable projections on various technical parameters
- A structured framework built into a system enable implementing all these checks

ERMS Solution Vision

Data warehouse for Utility Business Data

- Data repository capturing submitted and admitted values in ARR, APR
- Granular data store at monthly, seasonal level
- Historical data source for trend analysis, comparison

Data from External Data Source for comparison

- Data store capturing various rates e.g. PLR, inflation index WPI, CPI
- Escalation rates on various publications e.g. coal price escalation

Decision Support for internal computation

- Regulation norms driven rules
- Specific calculation model for each technical parameter based on business volume growth
- Analytics and rule driven models for insights and sensitivity analysis

Benchmarking for norms derivation

- With historical data set on various technical & financial parameters predictive models to enable deriving for future norms
- Rule driven insights to enable commission take decision to frame directives

Workflow Automation for petition filing

- A digital platform to enable online petition filing
- As per regulatory process, each step of petition filing to be tracked with date timestamp
- Automated notifications to stakeholders

System driven Order publishing

- Internal computation and justification for each regulatory process to be captured online
- System driven draft order generation with all outcomes of internal computation and their corresponding justifications

Example - Fuel Cost Determination

Key Elements to be determined

- Average Heat value of coal
- Average Heat value of oil
- Average price of coal
- Average price of oil

Granular Data Requirement

- Monthly gross generation
- Monthly grade-wise coal consumption
- Monthly coal invoices
- Monthly oil consumption
- Monthly oil invoices

Internal Computation Checks

- Annual, monthly, daily average GCV of coal billed, received and fired
- Correlation between monthly coal/oil consumption and gross generation
- Source wise grade wise coal procurement
- Justification of imported coals
- Analysis on penalty, demurrage
- Coal invoice analysis

Example - Power Purchase Cost Determination

Granular Data Driven Approach
• Validation of agreed generation availability plan as per long term PPAs (monthly break up) • Plant Availability Factor and Plant Load Factor validated against SLDC data • Computing monthly average load generation balance for 24 hour time block • Computation of shortfall and surplus and then categorizing them as scope of short term import/peak load management or export or non-drawal • Computation of backing down based on merit order of landed energy charges • Derivation of seasonal power purchase plan from the above calculations • Summary of power purchase cost

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Prototype Demonstration

Online Petition Form Submission

- Form fill up
- Auto calculation
- Document upload

Internal Computation

- Power Purchase Cost
- Coal Handling Charges
- Calculator based on escalation rate

Automatic Document generation for drafting Order

Appendix

Functional Modules in ERMS

Module 1
Aggregate Revenue Requirement/ Multi-Year Tariff

Module 2
Fuel Cost Adjustment (FCA)

Module 3
Fuel and Power Purchase Cost Adjustment (FPPCA)

Module 4
Annual Performance Review (APR)

Module 5
Monthly Fuel Cost Adjustment (MFCA)

Module 6
Monthly variable cost adjustment (MVCA)

Module 7
ARR Mid Term Review

Module 8
Investment proposal for Generation

Module 9
Investment proposal for T&D

Module 10
PPA for Distribution Licensees

Module 11
Compliance Monitoring

Module 12
Approval for Grant of Distribution Licensee

Module 13
Approval for Grant of Transmission Licensee

Module 14
Tariff Order Review

Module 15
Other Applications

Module 16
Application seeking exemption under section 13

Module 17
Rate charges for open access intervening transmission facilities

Module 18
Renewable Energy

Module 19
Micro grid

Module 20
Ancillary Services

Module 21
Approval of Grant of Power Trading Licensee

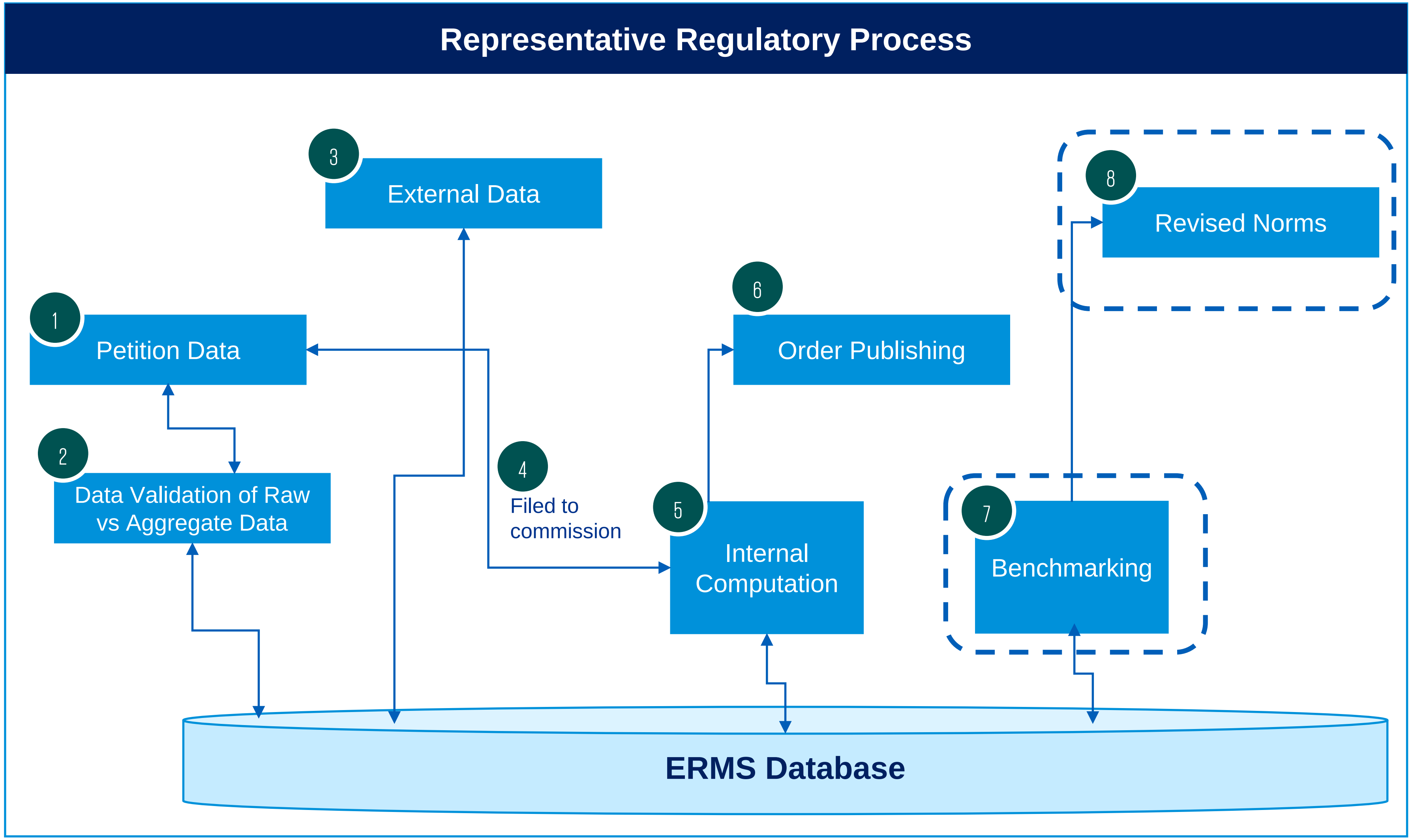
Module 22
MIS Reports

Module 23
Management Dashboard

Module 24
Document Management System

Module 25
Archival

Typical Regulatory Process



Process Steps

1. Petition data will be captured in ERMS database

2. Data validation between raw data and aggregate will be done

3. External data would be captured in the system on a regular basis

4. Licensee submits petition to commission

5. Commission conducts internal computation for admitting values on technical and financial parameters

6. Based on approved admitted values, commission publishes orders

7. Based on available data commission may conduct benchmarking exercise on various parameters

8. Commission may compute revised norms based on benchmarking

Petition Filing Process - Value Adds

Current State of the process

- Petition filing is manual through hard copy submission
- All communications, data correction, documentary evidences justifying petition data are done manually
- Tracking of petitions, progression of petition status are managed manually

To-Be State of the process

- Entire process from petition filing, admission, assessment, order publishing will be online
- All communications between commission and licensees would be through online system with audit trail of date timestamps. Hard copy letters would be available in ERMS repository.
- All communications can be accessed in ERMS in a systematic manner
- All the petition data and associated documents as attachment will be available logically for ease of access

Core Features in ERMS

- ERMS would track each stage such as petition submission, admission, internal computation, order publishing.
- At each stage completion, system generated notification will be sent to relevant stakeholders.
- Based on regulation defined due dates, automated reminders could be broadcast for activity completion
- All events such as submission, admission, order approval etc. will be captured in the system with date timestamp and user id.
- MIS report showcasing petition status, SLA compliance as per regulation defined deadlines will be available

Benefits

- No manual submission would be required and the instant petition is submitted by licensee, it would be visible to commission.
- Events like petition submission, admission etc. will be notified to applicable stakeholders through email and SMS
- Entire audit trail of all the activities in the petition filing process will be available in the system through a single click
- Proactive reminders on petition admission, assessment, approval enable commission to be on schedule
- Reports on petition status, aging, deadline breach etc. would enable measuring performance

Petition Data Validation Process - Value Adds

Current State of the process

- All data points as per regulation approved forms are submitted in hard copies.
- There is no easy way to validate if the common data points across different forms are same
- Submission of raw/ granular data lack standard templates and happens on a need basis, varies from licensee to licensee
- Validation of aggregate data as submitted in regulation approved forms and computed aggregated value from the raw data is completely manual
- There is repetitive submission of historical actual data due to manual process

To-Be State of the process

- The data submission for petition will happen through online forms
- Common data point occurring in multiple regulation approved forms would auto-populate in ERMS
- There won't be any duplicate entry of the same data
- Raw data submission will happen as per standardized templates
- The validation of aggregate data as per regulation approved forms and computed values based on raw data would be done by system
- ERMS would fetch historical actual data for each technical parameter so that repetitive submission of historical data won't be required

Core Features in ERMS

- System facilitates capturing annual as well as granular data at monthly/seasonal level as applicable
- System would automatically compute the annual data based on applying aggregation logic to the monthly granular data
- If the licensee input annual data does not match with system computed annual data from the monthly raw data, system flags the mismatches.
- Against such mismatches, system facilitate capturing justification by licensees unless it is corrected by licensees

Benefits

- The granular level data submitted by licensee in the system help calculate the annual values thus reducing possibilities of mismatches between transactional data and what is submitted to commission.
- Auto validation process enable licensee to correct any typo or wherever deviation is justified, licensee is mandated to provide justification.
- Since all deviations are accompanied with justification and typos are corrected based on system validations, no of queries from commission to licensees drastically reduce; - this overall reduces query cycle time and expedite petition admission.
- The deviation report enable commission to focus on specific technical/financial parameters for further analysis.

Internal Computation Process - Value Adds

Current State of the process

- Currently internal computation on any technical / financial parameter is manual.
- Finding and organizing requisite data for carrying out the computation is a tedious process and disjoint xls templates are used for calculation process.
- Other than a document or an xls, there is no central system where basis and justification of the computation carried out is captured.
- There is no standard way of deriving insights, dependencies and correlation between technical parameters.

To-Be State of the process

- System would by default conduct internal computation based on data submitted as part of regulation approved forms and additional raw data information. Wherever there are norms defined, it would be applied by the system and computation would happen automatically.
- On top of default set of computation, commission can change various parameters and tailor the computed values.
- Various statistical models, trends would enable commission users to derive insights as well as predict values for ensuing years
- Based on the internal computation conducted and admitted by commission, a document with prepopulated data tables, and justification would auto-generate from the system which can be used in drafting order.

Core Features in ERMS

- Based on the information submitted by Genco and licensee, various parameters will be plotted graphically to show the patterns and trends.
- Normative calculations will be automatically done by system.
- Multiple variables are also plotted to showcase correlation and dependencies.
- External data points such as WPI, CPI, PLR, Coal Price etc. are captured in the system to enable commission to configure its contribution % in a calculation.
- System would enable executing sensitivity analysis of selected technical/ financial parameter with respect to overall ARR or impact on tariff
- Commission can finalize the value to be admitted against the technical/financial parameters and would enter justification in the system in this regard.

Benefits

- All normative computations as per regulation will be done automatically through the system
- Data fetching for the purpose of computation, comparison with respect to any technical parameter for any year for any process e.g. ARR, APR etc. can be done through system in few clicks
- Commission can play around with various values for the purpose of admission to check how it is impacting other parameters. This enables commission to assess overall impact of admitting or disallowing certain cost elements.
- At a later point, any time commission wants to refer any calculation done earlier, commission can fetch the detailed calculation from the system including the justification given by commission as part of the calculation.

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Thank you

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Annexure-VI

Power Quality:
Report and Model Regulations

Meeting on 24.8.2018

Forum of Regulators

Sectt.: C/o. Central Electricity Regulatory Commission, New Delhi

Background of Working Group

- Electricity Act 2003 has enshrined the basic need of consumers to be provided with continuous, reliable and quality supply by the Distribution Utilities.

- Accelerated growth of renewable energy along with meteoric rise of non-linear loads pose challenges for quality of conventional unidirectional power flow from generation to consumption points.

- Poor quality of power lead to
  - premature failure or reduced/degraded performance of equipment.
  - Increased system losses.
  - Consumers are looking for clean and quality power to drive their sensitive equipment at all levels.

- 31st FOR meeting
  - need for greater regulatory intervention in ensuring quality of power supply
  - Need for effective compliance to power quality standards.

Constitution of the Working Group

1.	Chairperson, Central Electricity Regulatory Commission	Chairman of the Working Group
2.	Chairperson, Gujarat Electricity Regulatory Commission	Member
3.	Chairperson, Punjab Electricity Regulatory Commission	Member
4.	Chairperson, Assam Electricity Regulatory Commission	Member
5.	Chairperson, Arunachal Pradesh Electricity Regulatory Commission	Member
6.	Chairperson, Chattisgarh Electricity Regulatory Commission	Member
7.	Member (Technical) Bihar Electricity Regulatory Commission	Member
8.	APQI	Special Invitee

TOR of Working Group

I. Review of action initiated by various Regulating Agencies in line with Electricity Act 2003 provisions and international practice and to suggest possible further improvements.
II. Identify comprehensive study area to improve Power Quality (PQ) performance. The study may include :
    i. Benchmarking of Power Quality performance factors
    ii. Power Quality Improvement solutions
    iii. To identify polluting consumers by providing monitoring equipment in Distribution system
    iv. Adequacy of PQ compliance by RE Generators
    v. PQ in Smart Grid/Smart Transmission Grid/Green Energy Corridors
    vi. Power Quality performance indices linked to Annual Revenue Requirement (ARR)
    vii. Conduction of Power Quality audit
    viii. Cost of poor Power Quality affecting Indian Economy
    ix. Specifying PQ parameters which may be displayed by Licensees in the public domain
    x. Any other aspects which may influence PQ performance

TOR of Working Group (contd.)

III. The PQ performance factors may include:

(i)Voltage sags and swells

(ii)Voltage unbalance

(iii)Voltage harmonics and sub harmonics

(iv)Current Harmonics

(v)Flickers and fluctuation

(vi)Power Factor

IV. Any other items suggested by Chairperson FOR/members of Working Group.

Proceedings of Working Group

- First meeting: 27-02-2015, Bhuj
- Second meeting- 25-05-2015, New Delhi
- Third meeting-23-07-2018, New Delhi- Working group adopted the report of Subgroup and referred the report to FOR

Sub-Group on Power Quality

Shri A.S. Bakshi, Member, Central Electricity Regulatory Commission	Chairman of the Sub Group
Shri R.N. Nayak, Ex-Chairman-cum-Managing Director, Power Grid Corporation of India Ltd.	Co-Chair of the Sub Group
Shri R.N. Sen, Chairman, West Bengal Electricity Regulatory Commission	Member
Shri Anand Kumar, Chairman, Gujarat Electricity Regulatory Commission	Member
Shri P.S. Mhaske, Member-Power System, CEA	Member
Shri Manas Kundu, Representative of APQI	Member
Shri Akhil Kumar Gupta, Joint Chief (Engg.)	Member Secretary

Co-opted Members

Shri M.K. Iyer, Member, Central Electricity Regulatory Commission	Member
Shri Sukumar Mishra, IIT Delhi	Member
Shri S.C. Shrivastava, Chief (Engg.), CERC	Member Secretary
Ms. Anjuli Chandra, Member(PSERC)	Special Invitee

Proceedings of the Sub-group

- Six meetings
- 2.2.2016-6.7.2018
- Studies undertaken
  - LED bulbs testing by CPRI, Bangalore – PF, THD
  - TPDDL Study
  - POWERGRID Study – Swatch Power Report
- Expert Opinion
  - Professor Math Bollen, Lulea University, Sweden
    - At workshop during 4th meeting - 9.10.2017
  - EESL + BIS inputs on LED - IS 16102

Contents of Report

Chapter 5: Need for Model Power Quality Regulations

- Prescribed Limits for Harmonics, Voltage variation and Voltage Unbalance in different Regulations of SERCs
- What are different PQ Parameters which should be considered for Model Regulations on Power Quality?
  - Frequency Deviations
  - Harmonics
  - Voltage Variation and Flicker
  - Voltage Unbalance
  - Voltage Dips and Swells
  - Voltage Transients
  - Supply Voltage Interruptions
  - Power Factor

Chapter 8 : Case Studies and Observations

- Case study 1 – India's largest steel wire rope industry (Industry Sector)
- Case study 2 – Hospital (Service Sector)
- Case Study 3 – Food & Beverage Industry
- Case Study 4 – Utility Sector

Chapter 9: Recommendations

1. Need for Power Quality Regulations.
2. Should Reliability Indices be Part of the PQ Regulations?
3. Monitoring of Power Quality parameters at Transmission and Sub-Transmission System Level.
4. Which Power Quality Parameters need to be specified in PQ Regulations?
5. Locations for Power Quality Monitoring.
6. Incentive/ Dis-incentive Mechanism for Power Quality.
7. Integration of Power Quality with Smart Grid Applications in Distribution.
8. Power Quality Database.
9. Trainings in the area of Power Quality.
10. Power Quality Audits.

Recommendation 1: Need for Power Quality Regulations

- Separate Regulations covering
    - All Parameters (exhaustive list)
    - Incentive/Disincentive mechanism
    - Importance can be emphasized
    - Harmonious framework
    - Procedure for monitoring, management and control of all aspects of power quality.

Recommendation 2 – Reliability indices (SAIFI/ SAIDI also be part of PQ Regulations)

Recommendation 3: Monitoring of PQ parameters at Transmission and Sub-Transmission System Level.

- Few power Quality parameters is covered under CEA Standards/ CERC Grid Code / SERCs Supply code
- The entire value chain to be monitored to identify the polluter and install mitigating mechanism.
- Appropriate reporting and incentive/dis-incentive mechanism in their Grid/Supply Code for regular monitoring and control of the limits for power quality parameters at transmission and sub-transmission system level be taken up by Regulators.
- This report covers power quality parameters for the DISCOMs and the consumers connected at voltage level of 33kV and below in the distribution system.

Recommendation 4: Which PQ Parameters need to be specified in PQ Regulations?

- Harmonic Distortion,
- Voltage Variation & Flicker,
- Voltage Unbalance,
- Voltage Sags/Swells and
- Short & Long Supply Interruptions

- The limits for other power quality parameters could be included in Power quality Regulations by the SERCs based on their experience and specific system requirements
- The specified limits for various power quality parameters should be consistent and in line with the notified BIS Standards and/or applicable IEEE/IEC Standards
- The limits recommended for various power quality parameters as in Model Regulations on Power Quality may be specified till BIS/ CEA notifies their Distribution system supply voltage quality standards. Thereafter the BIS standards / CEA Standards limit may be implemented by SERCs

Recommendation 5: Locations for Power Quality Monitoring

- continuous monitoring and reporting at all the identified locations.
  - Phased Implementation
    - 50% of 33kV/11kV feeders, 25% DTRs
    - 100% 33kV/11 kV feeders, 60% DTRs
    - 100% DTRs
  - Arc furnace, Data Centres, Large Industries, Malls,
  - Distributed generation Source, Electrical vehicle Charging station, Prosumers
  - Input of transformer for solar/ wind generator
- The compliance may be reported in standard formats at regular intervals.
- For the initial phase, Regulators may direct Distribution Licensee to install Power Quality meters for all strategic locations and for bulk consumers with contract demand more than 1 MVA.

Recommendation 6: Incentive/ Dis-incentive Mechanism for Power Quality.

- Phased Implementation
- First year- compliance of all specified power quality parameters are reported in prescribed formats at regular intervals to the Regulators and put in public domain by posting on the website of the distribution licensees.
    - For identified industries within 6 months.
    - Existing mechanism should continue till new system is effective
- Second year - Incentive or Disincentive on the defaulters as per recommended Regulations.
- Third year- decide Incentive/Disincentive based on the experience and specific system requirements.
- Expenditure by licensee-pass through in ARR
- Disincentive paid by licensee cannot be pass through

Recommendation 7: Integration of PQ with Smart Grid Applications in Distribution

- Comprehensive metering is required
- Power quality be integrated with the smart grid application
  - advanced power quality meters,
  - wide-area power quality measurement,
  - power quality enhancement devices for system component and sensitive loads that can provide fast diagnosis and correction of PQ disturbances.
  - The power quality measurement for smart grid may be further extended for grid intelligence as part of the Power Quality Regulations.

Recommendation 8: Power Quality Database

- SERCs may fix the responsibility to maintain the PQ database by the distribution licensee or bulk consumers, as the case may be, for a sufficiently long period.
- Data security- not to be transferred/shared without permission

Recommendation 9: Trainings in the area of Power Quality

- Specify training requirements for DISCOM Engineers for effective implementations of the PQ standards.
- Consumer awareness
  - Effects of poor power quality
  - Disincentive
  - To install BIS compliant products

Recommendation 10: Power Quality Audits

- Compliance audit of PQ parameters by Independent agency.
- 100% audit by self once a year and 5% random audit through Independent Agency
- File results of Audit along with ARR True up.
- Power quality parameters should be published for awareness of the public and also ensures the stakeholders engagement through feedback system.

Model Regulations

- These Regulations shall apply to Distribution Licensee(s) including Deemed Distribution Licensee(s), distribution franchisees and all Designated Customer(s) of electricity connected at or below 33kV voltage level.

- Any failure by the Distribution Licensee or Designated Customer to achieve and maintain the power quality parameters specified in these Regulations shall render the Distribution Licensee or Designated Customer liable to payment of compensation under the EA 2003 to an affected entity claiming such compensation.

- Distribution licensee shall identify strategic locations in their electrical network and install the power quality meters at all such locations to maintain power quality in their supply area.

- Measurement methods for assessment of Power Quality under these Regulations shall be as per applicable notified IS and in absence of IS, IEC 61000-4-30:2015 namely 'Testing and measurement techniques – Power quality measurement methods' and as amended from time to time.

Power quality parameters to be controlled by

- distribution licensee :
  - Supply voltage variations
  - Supply voltage flicker
  - Supply voltage unbalance
  - Supply voltage dips and swells
  - Supply voltage harmonics
  - Supply Interruptions

- designated customers : Current harmonics

Other Aspects

- **Redressal of Consumer Complaints with regard to Power Quality:**
  - **2 days / 10 days / 180 days**

- Distrbution Licensee shall take following actions:
  - Submit the monthly and quarterly report of PQ parameters extracted from power quality meters and reliability data to the Commission.

  - Make efforts to improve power quality in their supply area by deploying devices to mitigate power quality issues such as filters or controllers etc. The expenses incurred towards deploying these devices by the distribution licensee shall be considered in the ARR.

- In case the designated customer does not take measures to reduce the level of current harmonics, he shall be made liable to pay higher compensation progressively on each continued violation as decided by the Commission separately. When there is no improvement in power quality even after 6 months, such consumers shall be served notice of dis-connection from the supply network and shall be disconnected after approval of the Commission.

Reliability Aspects

Reliability Indices	Limits *
SAIDI	600 Minutes per customer
SAIFI	15 interruptions per customer

*Limits may be decided based on area on supply and local conditions by SERC

- The feeders must be segregated into rural and urban and the value of the indices must be reported separately for each month.
- While calculating the given reliability indices, the following types of interruptions shall not be taken into account:
  - Momentary outages of duration less than three minutes.
  - Outages due to Force Majeure events such as cyclone, floods, storms , war, mutiny, civil commotion, riots, lightning, earthquake, lockout, grid failure, fire affecting licensee's installations and activities;
  - Outages that are initiated by the National Load Despatch Centre/ Regional Load Despatch Centre/State Load Despatch Centre during the occurrence of failure of their facilities;

Reliability Aspects

- Interruptions due to scheduled or planned outages shall be taken into account.
- Reliability indices to be based on data captured directly from the feeder monitoring system and there should not be any manual interventions as far as possible.
- The Distribution Licensee shall maintain data on the reliability indices specified above for each zone/circle/division/sub-division on a monthly basis.
- Monthly information on reliability indices to be put up on website of the Distribution Licensee and shall submit such report quarterly to the Commission.

Table 10: Level of compensation

PQ Parameter	Standard	Compensation Payable	Compensation Payable by
Voltage Variation	As per Table-1, 2 and 3	Rs.100/- per week or part thereof for which voltage variation was beyond the specified limits	Distribution Licensee to each consumer connected on the feeder/ designated DTR. These compensations shall be cumulative for each violation.
Voltage unbalance	$V_{unbalance} \leq 2\%$	Rs.100/- per week or part thereof for which voltage unbalance was beyond the specified limits	
Voltage dips or swells	Number of events per year as per Table- 4 and 5	Rs.50/- per event for which voltage dips or swell was beyond the specified limits	
Voltage Harmonics	$THD_V < 8\%$ for LV $THD_V < 5\%$ for MV and as per Table – 6	Rs.100/- per week or part thereof for which voltage harmonics was beyond the specified limits	

Current Harmonics	As per Table-7	Compensation shall be 50 paisa per unit for the duration for which current harmonics was beyond the specified limits.	Designated Customer to distribution licensee
Short Voltage Interruptions	Number of events per year as per Table- 8	Rs.50/- per instance for which voltage dips or swell was beyond the specified limits	Distribution Licensee to each consumer connected on the feeder/ designated DTR. These compensations shall be cumulative for each violation.
Long Supply Voltage Interruptions	SAIDI in Minutes per Customer as per Table- 9	5 paisa/min/kW of contract demand for which SAIDI was beyond the specified limits	
Long Supply Voltage Interruptions	SAIFI in interruption per customer as per Table- 9	Rs.50/- per interruption for which SAIFI was beyond the specified limits	

Treatment of compensation

- Compensation received by the distribution licensee from the designated customers shall be utilized only on the measures taken to improve power quality such as installation of filters, controllers etc.;

Thank You!

Supply Voltage Variation Limits

- For LV Systems Interconnected with Transmission System.

Supply Voltage Characteristic	Reference Time Frame	Limits
Mean r.m.s. value of the supply voltage over 10 min	95% of each period of one week	Un ± 10 %
	100% of time	Un + 10 % / - 15%

- MV Systems Interconnected with Transmission System.

Supply Voltage Characteristic	Reference Time Frame	Limits
Mean r.m.s. value of the supply voltage over 10 min	99% of each period of one week	Un ± 10 %
	100% of time	Un ± 15%

- LV and MV Systems not interconnected with Transmission System

Supply Voltage Characteristic	Reference Time Frame	Limits
Mean r.m.s. value of the supply voltage over 10 min	100% of time	Un +10 % / -15 %

- The supply voltage unbalance shall be maintained less than or equal to 2% by the distribution licensee.
- Supply Voltage Dip Limits for LV and MV Networks in Terms of Number of Events per Year

Residual Voltage (%)	**Duration t (ms)**				
	10 ≤ t ≤ 200	200 < t ≤ 500	500 < t ≤ 1000	1000 < t ≤ 5000	5000 < t ≤ 60000
90 > u ≥ 80	30	40	10	5	5
80 > u ≥ 70	30	40	5	5	5
70 > u ≥ 40	10	40	5	5	5
40 > u ≥ 5	5	20	5	5	5

Values of Individual Harmonic Voltages of the Supply Voltage in Percent of the Fundamental Voltage

Odd Harmonics (%)						Even Harmonics (%)		
Not Multiple of 3			Multiple of 3					
harmonic	LV	MV	harmonic	LV	MV	harmonic	LV	MV
5	6	6	3	5	5	2	2	1.9
7	5	5	9	1.5	1.5	4	1	1
11	3.5	3.5	15	0.5	0.5	6 to 24	0.5	0.5
13	3	3	21	0.5	0.5			
17	2	2						
19	1.5	1.5						
23	1.5	1.5						
25	1.5	1.5						

Values of Current distortion limits (TDD)

Maximum harmonic current distortion in percent of I_L						
Individual harmonic order (odd harmonics)a, b						
I_{SC}/I_L	$3 \le h < 11$	$11 \le h < 17$	$17 \le h < 23$	$23 \le h < 35$	$35 \le h \le 50$	TDD
< 20*	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0
> 1000	15.0	7.0	6.0	2.5	1.4	20.0

Short Voltage Interruptions Limits (number of events per year) for LV and MV Networks.

Residual Voltage (%)	Duration t (ms)				
	10 ≤ t ≤ 200	200 < t ≤ 500	500 < t ≤ 1000	1000 < t ≤ 5000	5000 < t ≤ 60000
5 > u	5	20	30	10	10

Annexure-VII

MODEL REGULATION ON POWER QUALITY FOR STATE – APPLICABLE FOR DISTRIBUTION SYSTEM

(STATE) ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Dated _________________

DRAFT NOTIFICATION

In exercise of powers conferred under section 181 of the Electricity Act, 2003 (36 of 2003) read with section 61, section 57 and section 59 thereof and all other powers enabling it in this behalf, and after previous publication, the [State] Electricity Regulatory Commission hereby makes the following regulations, namely:

CHAPTER - 1
PRELIMINARY

1. Short Title, Extent and Commencement

(1) These regulations may be called the [State] Electricity Regulatory Commission (Power Quality) Regulations, 2018;

(2) These Regulations shall extend to the whole of the [State].

(3) These Regulations shall come into force from the date of their publication in the Official Gazette.

2. **Definitions and Interpretations.**–In these regulations, unless the context otherwise requires -

(1) **'Act'** means the Electricity Act, 2003 (36 of 2003);

(2) **'Authority'** means the Central Electricity Authority;

(3) **'Consumer'** means any person who is supplied with electricity for his own use by a licensee or the Government or by any other person engaged in the business of supplying electricity to the public under the Act or any other law for the time being in force and includes any person whose premises are for the time being connected for the purpose of receiving electricity with the works of a licensee, the Government or such other person, as the case may be;

(4) **'Central Commission'** means the Central Electricity Regulatory Commission;

(5) **'Commission'** means the [State] Electricity Regulatory Commission;

(6) **'Continuous Phenomenon'** means deviations from the nominal value that occur continuously over time;

(7) **'Contract Demand'** means demand in kilowatt (kW)/kilovolt ampere (kVA)/Horse Power (HP) as mutually agreed between Distribution Licensee and the Consumer and as entered into in the agreement for which Distribution Licensee makes specific commitment to supply from time to time in accordance

with the governing terms and conditions contained therein or equal to the sanctioned load, where the contract demand has not been provided through /in the agreement;

(8) **'Declared Supply Voltage (Uc)'** means the voltage at the consumers supply terminals declared by the supplier of electrical energy. Declared supply voltage is usually equal to the nominal voltage;

(9) **'Designated Customers'** means the customers identified as major power quality polluters due to their installed non-linear loads or generation or otherwise under these Regulations and shall interalia include commercial buildings (Healthcare, Hotels, Airports, malls etc.), IT/ITES and Banking, Finance & Service Industries (BFSI), Automobiles, Iron & Steel, Aluminium, Textile, Paper & Pulp, Chlor-Alkali, Petro-Chemical, Cement, Pharmaceuticals, Fertiliser, Food Processing, Plastic & Rubber and Railways/Metros, grid connected distributed generating resource and Electric Vehicle Charging infrastructure etc.;

(10) **'Flicker'** means the impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time. It is caused under certain conditions by voltage fluctuation changing the luminance of lamps;

(11) **'Flicker Severity'** means intensity of flicker annoyance evaluated by the following quantities:

a) Short term severity (P_{st}) measured over a period of 10 min;
b) Long term severity (P_{lt}) calculated from a sequence of twelve P_{st}-values over a 2 hour time interval;

(12) **'Forum'** means as defined under [State] Electricity Regulatory Commission (Consumer Grievance Redressal Forum & Electricity Ombudsman) Regulations including any amendment thereto in force from time to time ;

(13) **'Frequency'** means the number of alternating cycles per second [expressed in Hertz (Hz)];

(14) **'Grid Code'** means the Grid/Distribution Code as specified by the [State] Electricity Regulatory Commission;

(15) **'Grid Standards'** means the Grid Standards specified by the Authority;

(16) **'Harmonics'** means the sinusoidal component of a periodic wave, either Voltage or Current waveform, having a frequency that is an integral multiple of the fundamental frequency of 50 Hz;

(17) **'High Voltage'** means the voltage whose nominal r.m.s. value is more than 33000 volts but less than or equal to 150000 volts as per IS 12360:1988 standard;

(18) **'Indian Standards (IS)'** means standards specified by Bureau of Indian Standards;

(19) **'IEC Standard'** means a standard approved by the International Electrotechnical Commission;

(20) **'Interconnection Point (Distribution System)'** a point on the electricity system, including a sub-station or switchyard, where the interconnection is established between the customer and the electricity system of the distribution licensee and where electricity injected into or drawn from the electricity system can be measured unambiguously for the customer;

(21) **'licensee'** means the distribution licensee;

(22) **'Low Voltage (LV)'** means the voltage whose nominal r.m.s. value is less than or equal to 1000 Volts as per IS 12360:1988 standard;

(23) **'Medium Voltage (MV)'** means the voltage whose nominal r.m.s. value is more than 1000 volts but less than or equal to 33000 volts as per IS 12360:1988 standard;

(24) **'Maximum demand load current'** means the current value at the point of common coupling calculated as the sum of the currents corresponding to the maximum 15 minute demand during each of the twelve previous months divided by 12;

(25) **'Nominal voltage (of the Distribution System) (Un)'** means the value of voltage by which the electrical installation or part of the electrical installation is designated and identified;

(26) **'Normal Operating Condition' means o**perating condition for an electricity network, where generation and load demands meet, system switching operations are concluded, faults are cleared by automatic protection systems

and in the absence of:

i. temporary supply arrangement;

ii. exceptional situations such as:

a. exceptional weather conditions and other natural disasters;

b. force majeure;

c. third party interference;

d. acts by public authorities;

e. industrial actions (subject to legal requirements);

f. power shortages resulting from external events

(27) **'Nominal Frequency'** means the frequency of 50.00 Hz of the supply voltage.

(28) **'Point of Common Coupling (PCC)'** means the point of metering, or any other point on supply system of distribution licensee, electrically nearest to the particular load at which other loads are, or could be, connected. For service to industrial users (i.e., manufacturing plants) via a dedicated service transformer, the PCC is usually at the HV side of the transformer. For commercial users (office parks, shopping malls, etc.) supplied through a common service transformer, the PCC is commonly at the LV side of the service transformer.

(29) **'Power Factor' or 'Displacement Power Factor'** means the cosine of the electrical angle between the voltage and current vectors in an AC electric circuit;

(30) **'Power Quality Meter'** means a device suitable for monitoring and recording of power quality. It shall be capable of accurate measurement, monitoring and recording of harmonics, sags, swells, flickers and other power quality parameters;

(31) **'Rural areas'** mean the areas covered by Gram Panchayats, including major and minor Panchayats;

(32) **'r.m.s. (root-mean-square) value'** means square root of the arithmetic mean of the squares of the instantaneous values of a quantity taken over a specified time interval and a specified bandwidth;

(33) **'Sanctioned load'** means load in kilowatt (kW)/kilovolt ampere (kVA)/Horse Power (HP) for which the Distribution Licensee had agreed to supply from time

to time subject to governing terms and conditions;

(34) **'Supply Area'** means the area within which a Distribution Licensee is authorised by his License to supply electricity;

(35) **'Supply Terminals'** means point in a distribution system designated as such and contractually fixed, at which electrical energy is exchanged between the Customer and distribution licensee. This point can differ from the electricity metering point or the point of common coupling.

(36) **'Supply Voltage'** means the r.m.s. value of the voltage at a given time at the supply terminal, measured over a given interval;

(37) **'Supply Voltage Interruption'** is a condition in which the voltage at the supply terminals is completely lost or lower than 10% of the nominal voltage condition. It can be classified as:

a) **Planned or Prearranged Supply Interruptions** means a supply interruption when network users are informed in advance;

b) **Forced or Accidental Supply Interruptions**, caused by permanent or transient faults, mostly related to external events, equipment failures or interference.

c) A Planned or forced supply interruption is classified as:

   1) **Sustained or long interruption** means supply interruption is longer than 3 min;

   2) **Short interruption** means supply interruption is from 20ms to 3 min;

d) For poly-phase systems, a supply interruption occurs when the voltage falls below 10% of the nominal voltage on all phases (otherwise, it is considered to be a dip).

(38) **'Supply voltage dip'** means a temporary reduction of the r.m.s. supply voltage at a given point in the electrical supply system of 10 to 90% of the declared voltage for a duration from 10 ms up to and including 1 min. Typically a dip is associated with the occurrence and termination of a short-circuit or other extreme current increase on the system or installation connected to it;

(39) **'Supply voltage dip duration'** means time between the instant at which the r.m.s. voltage falls below the start threshold and the instant at which it rises to

the end threshold. For poly-phase events, a dip begins when one voltage falls below the dip start threshold and ends when all voltages are equal to or above the dip end threshold.

(40) **'Supply voltage dip end threshold'** means r.m.s. value of the supply voltage specified for the purpose of defining the end of a supply voltage dip;

(41) **'Supply voltage dip start threshold'** means r.m.s. value of the supply voltage specified for the purpose of defining the start of a supply voltage dip;

(42) **'Supply voltage dip Residual Voltage'** means minimum value of r.m.s. voltage recorded during a voltage dip;

(43) **'Supply voltage swells (temporary Power Frequency Overvoltage)**' means temporary increase in the r.m.s. supply voltage at a given point in the electrical supply system above 110 of the declared voltage for a duration from 10 ms up to and including 1 min;

(44) **'Supply voltage swell duration'** means time between the instant at which the r.m.s. voltage exceed the start threshold and the instant at which it falls below the end threshold;

(45) **'Supply voltage swell end threshold'** means r.m.s. value of the supply voltage specified for the purpose of defining the end of a supply voltage swell;

(46) **'Supply voltage swell start threshold'** means r.m.s. value of the supply voltage specified for the purpose of defining the start of a supply voltage swell;

(47) **'System Average Interruption Duration Index' (SAIDI)** means the average duration of sustained interruptions per consumer occurring during the reporting period, determined by dividing the sum of all sustained consumer interruptions durations, in minutes, by the total number of consumers;

(48) **'System Average Interruption Frequency Index' (SAIFI)** means the average frequency of sustained interruptions per consumer occurring during the reporting period, determined by dividing the total number of all sustained consumer interruption by the total number of consumers;

(49) **'True Power Factor'** means the ratio between total active power used in a circuit (including harmonics) and the total apparent power (including harmonics) supplied from the source. True power factor is always less than

displacement power factor if harmonics are present in the system;

(50) **'Transient over voltages'** means short duration oscillatory or non-oscillatory over voltages usually highly damped and with duration of few ms or in microseconds;

(51) **'Total Demand Distortion (TDD)'** means the ratio of the root mean square of the harmonic content, considering harmonic components up to the 50th order, expressed as a percent of the maximum demand current;

(52) **'Total Harmonic Distortion' or 'THD'** means the ratio of the root mean square of the current harmonic content, considering harmonic components up to the 50th order, expressed as a percent of the fundamental;

(53) **'Voltage Events'** means sudden and significant deviations from normal or desired wave shape. Voltage events typically occur due to unpredictable events (e.g. faults) or due to external causes (e.g. weather conditions);

(54) **'Voltage Fluctuation' or 'Voltage Variations'** means series of voltage changes or a cyclic variation of the voltage envelope, the magnitude of which does not normally exceed the specified voltage ranges;

(55) **'Voltage unbalance'** means a condition in a poly-phase system in which the r.m.s. values of the line-to-line voltages (fundamental component), or the phase angles between consecutive line voltages, are not all equal. The degree of inequality is usually expressed as the ratios of negative and zero sequence components to the positive sequence component;

(56) **'Urban Areas'** means the areas covered by all Municipal Corporations and other Municipalities including the areas falling under the various Urban Development Authorities, Cantonment Authorities and Industrial Estate and Townships including those specified by the[State] Government;

The words and expressions used in these regulations and not defined herein but defined in the Act or any other regulation of the Commission shall have the meaning assigned to them under the Act or any other regulation of the Commission respectively.

CHAPTER – 2

GENERAL

3. Objectives

(1) The Power Quality of the electrical system refers to both the extent of deviation or distortion in pure supply waveform and the continuity of supply. An ideal power supply is never interrupted, always within voltage and frequency tolerances and has a noise free sinusoidal waveform. Poor power quality causes performance degradation and premature failures of electrical equipment. It also results in increased system losses.

(2) Different type of disturbances that affects the power quality include Harmonics (waveform distortion), frequency deviations, voltage unbalance, voltage fluctuations, flicker, supply interruptions, transient overvoltage or surges, voltage dips and voltage swell etc. Each of these disturbances has different causes and effects.

(3) Power quality disturbances can propagate upstream or downstream and could affect other customers connected in the same supply network. Power quality monitors are available to measure all aspects of power quality.

(4) The objective of standards specified in these Regulations is to ensure the quality and reliability of electricity supplied by the distribution licensee to the end consumers and by the designated customers.

(5) Any failure by the Distribution Licensee or Designated Customer to achieve and maintain the power quality parameters specified in these Regulations shall render the Distribution Licensee or Designated Customer liable to payment of compensation under the EA 2003 to an affected entity.

4. Assessment of Power Quality

(1) The assessment of Power Quality shall consist of measuring the various parameters of the power quality and comparing them with the standards specified in these regulations.

(2) Measurement methods for assessment of Power Quality under these Regulations shall be as per applicable notified IS and in absence of IS, it shall be as per IEC 61000-4-30:2015 namely 'Testing and measurement techniques – Power quality measurement methods' and as amended from time to time.

(3) For three phase four-wire connections, the line to neutral voltages shall be considered. For three phase three-wire connections the line to line voltages shall be considered. For single phase connections, the supply voltage (line to line or line to neutral, according to the network user connection) shall be considered

5. **Scope and extent of application**

(1) These Regulations shall apply to Distribution Licensee(s) including Deemed Distribution Licensee(s), distribution franchisees and all Designated Customer(s) of electricity connected at or below 33kV voltage level.

(2) The scope of these Regulations is to specify the main characteristics of power quality of electrical supply at point of common coupling (PCC) or at supply terminals of Customers in distribution system. The characteristics of power quality of electrical supply considered in these Regulations to be controlled by distribution licensee are:

i. Supply voltage variations

ii. Supply voltage flicker
iii. Supply voltage unbalance
iv. Supply voltage dips and swells
v. Supply voltage harmonics
vi. Supply Interruptions

The characteristic of power quality of electrical supply considered in these Regulations to be controlled by designated customers is:

vii. Current harmonics

(3) These regulations unless reviewed earlier, shall remain in force from the date of notification in official gazette.
(5) The limits specified in these Regulations for power quality parameters shall apply only under normal operating conditions.

6. Roles and Responsibilities
(1) Distribution licensee shall be responsible to their consumers for supplying electricity with adequate power quality levels as defined in these Regulations.

(2) Distribution licensee shall identify strategic locations in their electrical network and install the power quality meters at all such locations to maintain power quality in their supply area.

(3) Distribution licensee to identify the designated customers which are major power quality polluters and inject harmonics into the distribution system beyond the limits specified in these Regulations.

(4) The designated customers shall be responsible to control the harmonic injection into the distribution system within the limits specified in these Regulations.

7. Redressal of Consumer Complaints with regard to Power Quality: The consumer complaints in relation to the Power Quality shall be redressed in the following manner in accordance with these Regulations as under:
(1) On receipt of a power quality complaint, the distribution licensee shall demonstrate and satisfy that it meets the requirement of Power Quality standards specified in these Regulations.
(2) In case of complaint on voltage variations, unbalance and voltage harmonics, distribution licensee shall –

i. ensure that the power quality parameters are brought within the specified limits within 2 days of the receipt of a complaint, provided that the fault is identified to a local problem.
ii. ensure that the power quality parameters are brought within the specified

limits, within 10 days of the receipt of a complaint, provided that no expansion/enhancement of the network is involved; and

iii. resolve the complaint within 180 days, provided that if up-gradation of the distribution system is required.

(3) Where, the designated customer is required to demonstrate that he meets the requirement of Power Quality standards, a reasonable period may be given to the designated customer on case to case basis.

(4) The consumer, who is aggrieved by non-redressal of his grievances of Power Quality, may make a representation for the redressal of his grievance to Grievance Redressal Forum and Ombudsman.

(5) The cost of the verification shall be borne by the distribution licensee.

CHAPTER – 3
STANDARDS OF POWER QUALITY

8. Supply Voltage Variations

(1) The supply voltage variations in LV and MV networks from declared voltage shall comply with Table given below and specified with reference to mean r.m.s. values of supply voltage measured over 10 min.

Table 1 – Supply Voltage Variation Limits for LV Systems Interconnected with Transmission System.

Supply Voltage Characteristic	**Reference Time Frame**	**Limits**
Mean r.m.s. value of the supply voltage over 10 min	95% of each period of one week	*Un* ± *10 %*
	100% of time	*Un + 10 % / - 15%*

Table 2 – Supply Voltage Variation Limits for MV Systems Interconnected with Transmission System.

Supply Voltage Characteristic	**Reference Time Frame**	**Limits**
Mean r.m.s. value of the supply voltage over 10 min	99% of each period of one week	*Un* ± *10 %*
	100% of time	*Un* ± *15%*

Table 3 – Supply Voltage Variation Limits for LV and MV Systems not interconnected with Transmission System

Supply Voltage Characteristic	**Reference Time Frame**	**Limits**
Mean r.m.s. value of the supply voltage over 10 min	100% of time	*U*n +10 % / -15 %

Provided that:

The measurements shall be undertaken in accordance with applicable notified IS and in absence of IS, IEC 61000-4-30:2015 as amended from time to time;

For statistical evaluation, voltage variations shall be assessed for the period not less than 7 continuous days. The short time 10 min values (measured as per IEC) are accumulated over periods of one week and the 95th and 99th percentile values (i.e., those values that are exceeded for 5% and 1% of the measurement period) are calculated for each 7-day period for comparison with the recommended limits. The values are measured in normal operating condition.

For poly-phase systems, the voltage variations shall be measured in all phases of supply.

9. Supply Voltage Flicker (P_t)

(1) The voltage flicker shall be assessed in two different severity level: Long-Term severity (P_{lt}) and Short-Term severity (P_{st}). Short term severity shall be measured over a period of 10 min and long term severity shall be calculated from a sequence of twelve P_{st}-values over a 2 hour time interval, according to the following expression:

$$P_{lt} = \sqrt[3]{\sum_{i=1}^{12} \frac{P_{st}^3}{12}}$$

The permissible limits of short-term voltage flicker and long-term voltage flicker severity for distribution licensee shall be 1.0 and 0.8 at all supply terminals 100% of the time respectively.

Provided that:

The measurements shall be undertaken in accordance with IEC 61000-4-30;

For statistical evaluation, voltage flicker shall be assessed for the period not less than 7 continuous days. The short time 10 min values are accumulated over periods of one week and the 95th percentile values (i.e., those values that are exceeded for 5% of the measurement period) are calculated for each 7-day period for comparison with the recommended limits. The values are measured in normal operating condition excluding the time period of a voltage dip.

For poly-phase systems, the voltage flicker shall be measured in all phases of supply.

10. Supply Voltage Unbalance (UB)

(1) The supply voltage unbalance in respect of three phase supply shall be assessed from the ratio of rms value of negative phase sequence component (fundamental) to the rms value of positive phase sequence component (fundamental) of the supply voltage. The supply voltage unbalance shall be maintained less than or equal to 2% by the distribution licensee.

Provided that:

For statistical evaluation, voltage unbalance shall be assessed for the period not less than 7 continuous days. The short time 10 min values are accumulated over periods of one week and the 95th percentile values (i.e., those values that are exceeded for 5% of the measurement period) are calculated for each 7-day period for comparison with the recommended limits. The values are measured in normal operating condition.

11. Voltage Dip or Sag

(1) The Supply voltage dips shall comply with Table given below and are specified with reference to:

i. Number of events per year
ii. Event duration (t)
iii. Residual Voltage (u)
iv. Declared voltage (Uc)

Table 4: Supply Voltage Dip Limits for LV and MV Networks in Terms of Number of Events per Year

Residual Voltage (%)	**Duration t (ms)**				
	10 ≤ t ≤ 200	**200 < t ≤ 500**	**500 < t ≤ 1000**	**1000 < t ≤ 5000**	**5000 < t ≤ 60000**

90 > u ≥ 80	30	40	10	5	5
80 > u ≥ 70	30	40	5	5	5
70 > u ≥ 40	10	40	5	5	5
40 > u ≥ 5	5	20	5	5	5

Provided that:

The voltage dips shall be measured in accordance with IEC 61000-4-30 and shall not fall outside the duration from 10 ms up to and including 1 min;

The voltage dips shall be measured in all phases of supply.

12. Voltage Swells

(1) The Supply voltage swell shall comply with Table given below and are specified with reference to:

i. Number of events per year
ii. Event duration (t)
iii. Swell Voltage (u)
iv. Declared voltage (Uc)

Table 5: Supply Voltage swell Limits for LV and MV Networks in Terms of Number of Events per Year

Swell Voltage u (%)	**Duration t (ms)**		
	10 ≤ t ≤ 500	**500 < t ≤ 5000**	**5000 < t ≤ 60000**
u ≥ 120	--	--	--
120 > u ≥ 110	--	--	--

Values may be as per relevant IEC/IEEE Standard

Provided that:

The voltage swell shall be measured in accordance with IEC 61000-4-30 and shall not fall outside the duration from 10 ms up to and including 1 min;

The voltage swell shall be measured in all phases of supply.

13. Voltage Harmonics

(1) The voltage harmonic distortion of the supply voltage shall be assessed in terms of the Total Harmonic Distortion (THD_V) considering harmonic components up to the 50^{th} order. THD_V shall be taken as square root of the sum of squares of all voltage harmonics expressed as a percentage of the magnitude of the fundamental measured with following formula:-

$$THD_V = \sqrt{\sum_{h=2}^{N} V_h^2}$$

Where,

V_h represents the percent rms value of the h^{th} harmonic voltage component, and N represents the highest harmonic order considered in the calculation.

The distribution licensee shall control the value of THD_V measured at Point of Common Coupling (PCC) for LV and MV network to less than or equal to 8% and 5% respectively for 100% of time.

(2) The distribution licensee shall also control the mean rms values of each individual harmonic voltage measured over 10 minutes period up to the 25th harmonic order component to the values as given in table below:

Table 6: Values of Individual Harmonic Voltages of the Supply Voltage in Percent of the Fundamental Voltage

Odd Harmonics (%)						Even Harmonics (%)		
Not Multiple of 3			Multiple of 3					
harmonic	**LV**	**MV**	**harmonic**	**LV**	**MV**	**harmonic**	**LV**	**MV**
5	6	6	3	5	5	2	2	1.9
7	5	5	9	1.5	1.5	4	1	1
11	3.5	3.5	15	0.5	0.5	6 to 24	0.5	0.5
13	3	3	21	0.5	0.5			
17	2	2						
19	1.5	1.5						
23	1.5	1.5						
25	1.5	1.5						

(3) For statistical evaluation, voltage harmonics shall be assessed for the period not less than 7 continuous days. The short time 10 min values are accumulated over periods of one week and the 95th percentile values (i.e., those values that are exceeded for 5% of the measurement period) are calculated for each 7-day period for comparison with the recommended limits. The values are measured at PCC in normal operating condition.

Provided that:

The limits of each individual voltage harmonics by the distribution licensee in its electricity system, point of harmonic measurement i.e. Point of Common Coupling (PCC), method of harmonic measurement and other matters shall be in accordance with per applicable notified IS and in absence of IS, the IEEE 519-2014 namely 'IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems', as modified from time to time.

14. Current Harmonics

(1) The designated customers shall limit the value of harmonic currents measured at Point of Common Coupling (PCC) measured over 10 minutes period to the values as given in table below:

Table 7: Values of Current distortion limits (TDD)

Maximum harmonic current distortion in percent of I_L						
Individual harmonic order (odd harmonics)[a, b]						
I_{SC}/I_L	$3 \leq h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h \leq 50$	TDD
< 20*	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0

> 1000	15.0	7.0	6.0	2.5	1.4	20.0

Note: * All power generation equipment is limited to these values of current distortion, regardless of actual I_{SC}/I_L;

[a]Even harmonics are limited to 25% of the odd harmonic limits above;

[b]Current distortions that result in a dc offset, e.g., half-wave converters, are not allowed;

where

I_{SC} = maximum short-circuit current at PCC;

I_L = maximum demand load current (fundamental frequency component);

(2) For statistical evaluation, current harmonics shall be assessed for the period not less than 7 continuous days. The short time 10 min values are accumulated over periods of one week and the 95th and 99th percentile values (i.e., those values that are exceeded for 5% and 1% of the measurement period) are calculated for each 7-day period for comparison with the recommended limits. The values of TDD are measured at PCC in normal operating condition.

Provided that:

The weekly 95th percentile short time 10 min harmonic current values should be less than the value given in above Table-7. However, the weekly 99th percentile short time 10 min harmonic current values should be less than 1.5 times the value given in above Table-7.

The limits of current harmonics injected by the designated customer, point of harmonic measurement i.e. Point of Common Coupling (PCC), method of harmonic measurement and other matters shall be in accordance with per applicable notified IS and in absence of IS, the IEEE 519-2014 namely 'IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems', as modified from time to time.

The measurements undertaken to determine compliance shall be carried out in accordance with the requirements as specified in IEC 61000-4-7 and IEC 61000-4-30.

15. Short Supply Voltage Interruptions

(1) Short voltage interruptions shall comply with Table given below and are specified with reference to:

i. Number of events per year
ii. Event duration (t)
iii. Declared voltage (Uc)

Table 8: Short Voltage Interruptions Limits (number of events per year) for LV and MV Networks.

Residual Voltage (%)	**Duration t (ms)**				
	10 ≤ t ≤ 200	**200 < t ≤ 500**	**500 < t ≤ 1000**	**1000 < t ≤ 5000**	**5000 < t ≤ 60000**
5 > u	5	20	30	10	10

Provided that:

The short voltage interruptions shall be measured in accordance with IEC 61000-4-30 and shall not fall outside the duration from 10 ms up to and including 1 min;

The voltage swell shall be measured in all phases of supply.

16. Long or Sustained Supply Voltage Interruptions

(1) The Distribution Licensee shall calculate the reliability of its distribution system on the basis of number and duration of sustained or long supply voltage interruptions (longer than 3 min) in a reporting period, using the following indices:

i. System Average Interruption Frequency Index (SAIFI);

ii. System Average Interruption Duration Index (SAIDI);

(2) The Indices shall be computed for the distribution licensees for each month for all the 11kV and 33kV feeders in the supply area, and then aggregating the number and duration of all interruptions in that month for each feeder. The Indices shall be computed using the following formulae:

$$SAIFI = \frac{\sum_{i=1}^{N} A_i * N_i}{N_t}$$

$$\mathrm{SAIDI} = \frac{\sum_{\mathrm{i=1}}^{\mathrm{N}} \mathrm{B_i} * \mathrm{N_i}}{\mathrm{N_t}}$$

Where,

A_i = Total number of sustained interruptions (each longer than 3 min) on i^{th} feeder for the month;

Bi = Total duration in minutes of all sustained interruptions (longer than 3 min) on i^{th} feeder for the month;

N_i = Number of Customers on i^{th} feeder affected due to each sustained interruption;

N_t = Total number of customers served by the Distribution Licensee in the supply area;

n = number of 11kV and 33kV feeders in the licensed area of supply;

(3) The distribution licensee shall maintain the reliability on monthly basis within the limits specified in table below:

Table 9: Limits for Reliability indices

Reliability Indices	Limits *
SAIDI	600 Minutes per customer
SAIFI	15 interruptions per customer

*Limits may be decided based on area on supply and local conditions by SERC.

Provided that:

The feeders must be segregated into rural and urban and the value of the indices must be reported separately for each month.

While calculating the given reliability indices, the following types of interruptions shall not be taken into account:

i. Momentary outages of duration less than three minutes.

ii. Outages due to Force Majeure events such as cyclone, floods, storms , war, mutiny, civil commotion, riots, lightning, earthquake, lockout, grid failure, fire affecting licensee’s installations and activities;

iii. Outages that are initiated by the National Load Despatch Centre/ Regional Load Despatch Centre/State Load Despatch Centre during the occurrence of failure of their facilities;

While calculating the given reliability indices, the interruptions due to scheduled or planned outages shall be taken into account.

The distribution licensee shall capture reliability indices data directly from the feeder monitoring system and there should not be any manual interventions as far as possible.

The Distribution Licensee shall maintain data on the reliability indices specified above for each zone/circle/division/sub-division on a monthly basis.

The Distribution Licensee shall put up, at the end of each month, such monthly information on reliability indices, on website of the Distribution Licensee and shall submit such report quarterly to the Commission.

CHAPTER – 4

MONITORING AND REPORTING OF THE POWER QUALITY

17. Monitoring of Power Quality

(1) PQ measurement shall be implemented in phased manner and during first phase, PQ meters shall be installed at selective representative locations based on voltage level, type of consumers and significance of the power quality in such a way that such measurements should adequately represent the Power Quality and Reliability in the area of supply.

(2) The distribution licensee for the purpose of requirements for the quality of electricity supplied shall identify the locations of 33kV/11kV feeders, Distribution Transformers (DTRs) and designated customers to ensure the measurement of the power quality parameters at sufficient locations in their electrical networks to adequately characterize and report performance in terms of these Regulations. The feeders and DTRs should be identified for PQ monitoring based on type of load connected.

(3) The distribution licensee shall enforce the continuous monitoring of power quality standards at the inter-connection point of identified locations at or below 33kV voltage level for development of profile of power quality measurement in the area of supply;

(4) In the first phase, the distribution licensee shall install Power Quality meters for 50% of total 33kV/11kV feeders, 25% of total DTRs and at all designated customers supply terminals or at point of common coupling (PCC). In the second phase, Distribution Licensee shall cover 100% of 33kV/11kV feeders and at least 60% DTRs. In the third phase 100% DTRs shall be covered.

(5) The measurements undertaken to determine compliance shall be carried out in accordance with the requirements as specified in IEC 61000-4-7 and IEC 61000-4-30. There shall be continuous metering of harmonics with permanent Power Quality meters complying with the IEC 61000-4-30 Class-A meters for all new installations/connections of identified locations. For existing installations/ connections at identified locations where CTs/PTs are of lower accuracy class than mandated by IEC 61000-4-30 Class-A meters, the meters complying with the IEC 61000-4-30 Class-B may be installed. These meters should be capable of detecting direction of Harmonics (whether it is upstream or downstream) for all new installations at identified locations.

(6) In the event when the distribution licensee receives a customer complaint concerning Power Quality, the distribution licensee shall deploy power quality meter for a particular period for the purpose of verification. Distribution licensee can also measure the level of harmonics generation at PCC of any consumer(s) on receipt of complaint(s) from other affected consumer(s).

(7) These Regulations specifies the minimum requirements for Power Quality meters for measurement at sites directly affecting the quality of the power supplied to the consumer(s). The distribution licensee may require the additional PQ meters to establish the power quality at other bulk supply points and at other major network nodes and to investigate consumer(s) complaints, for which these additional PQ meters may be installed temporarily.

(8) The distribution licensee may opt to integrate the smart grid meters compatible for measurement of the PQ parameters for economic and operational optimization.

18. Compliance of the Power Quality and Reliability Standards

(1) The distribution licensee shall submit the monthly and quarterly report of information collected on PQ parameters extracted from power quality meters and machine based reliability data in standard formats (as specified separately) to the Commission.
(2) It shall be the prime responsibility of the distribution licensee to comply with these Regulations and submit the compliance report every 6 months in standard formats (as specified separately), including transparent data disclosure regarding electrical system, to the Commission. Commission may direct designated agencies to be notified separately, to carry out PQ audit on the basis of compliance reports filed by distribution licensee for verification. The distribution company shall carry out 100% audit by itself once a year and 5% random audit by the independent agency and shall file the audit report along with ARR truing up petition.

(3) The distribution licensee shall publish the reports indicating the compliance with the standards under these Regulations and post all the reports on its website. The distribution licensee shall also seek comments, if any, on the same from the customers availing supply from the distribution licensee.
(4) The Commission from time to time may seek reports on PQ improvements from distribution licensee.
(5) The distribution licensee shall make efforts to improve power quality in their supply area by deploying devices to mitigate power quality issues such as filters or controllers etc. The expenses incurred towards deploying these devices by the distribution licensee shall be considered in the ARR.
(6) The distribution companies shall ensure the data security and the data should only be used for identified purpose and should not be transferred to any other person without the consent of the specific consumer.

CHAPTER – 5

INCENTIVE / DIS-INCENTIVE MECHANISM FOR POWER QUALITY

19. Incentive/dis-incentive mechanism for Power Quality

(1) During the first year after notification of Power Quality Regulations, there shall be monitoring and reporting of power quality parameters by distribution licensee in prescribed standard formats at regular intervals. Therefore, there shall not be any incentive/dis-incentive for the stakeholders during the first year after notification or as may be specified by SERCs.

(2) The expenses incurred towards implementation and monitoring of power quality parameters by the distribution licensee shall be considered in the ARR.

(3) From the second year after notification of PQ Regulations, an incentive/dis-incentive mechanism shall be implemented for distribution licensees and for designated customers. The distribution licensees or designated customers shall be liable to pay compensation.

Provided that the Distribution Licensee shall compensate the affected person(s) in second-next billing cycle. In case the Distribution Licensee fails to pay the compensation or if the affected person is aggrieved by non-redressal of his grievances, he may make a representation for the redressal of his grievance to the concerned Consumer Grievance Redressal Forum.

Provided further that such compensation shall be based on the classification of such failure as determined by the Commission and the payment of such compensation shall be paid or adjusted in the consumer's future bills (issued subsequent to the award of compensation) within thirty (30) days of a direction issued by the Forum or by the Ombudsman, as the case may be.

(3) The Distribution Licensee shall not be excused from failure to maintain the power quality parameters under these Regulations, where such failure can be attributed to negligence or deficiency or lack of preventive maintenance of the distribution system or failure to take reasonable precaution on the part of the Distribution Licensee.

(4) The designated customers shall be liable to pay compensation for injecting current harmonics in to the supply system beyond the specified limits as given in Table below. In case the designated customer does not take measures to reduce the level of current harmonics (which is measured in terms of total demand distortion), he shall be made liable to pay higher compensation progressively on each continued violation as decided by the Commission separately. When there is no improvement in power quality even after 6 months, such consumers shall be served notice of dis-connection from the supply network and shall be disconnected after approval of the Commission.

(5) Level of compensation payable for failure to meet power quality standards are given in table below:

Table 10: Level of compensation

PQ Parameter	**Standard**	**Compensation Payable**	**Compensation Payable by**
Voltage Variation	As per Table-1, 2 and 3	Rs.100/- per week or part thereof for which voltage variation was beyond the specified limits	Distribution Licensee to each consumer connected on the feeder/
Voltage	$V_{unbalance} \leq 2\%$	Rs.100/- per week or part	

unbalance		thereof for which voltage unbalance was beyond the specified limits	designated DTR. These compensations shall be cumulative for each violation.
Voltage dips or swells	Number of events per year as per Table- 4 and 5	Rs.50/- per event for which voltage dips or swell was beyond the specified limits	
Voltage Harmonics	$THD_V < 8\%$ for LV $THD_V < 5\%$ for MV and as per Table - 6	Rs.100/- per week or part thereof for which voltage harmonics was beyond the specified limits	
Current Harmonics	As per Table-7	Compensation shall be 50 paisa per unit for the duration for which current harmonics was beyond the specified limits.	Designated Customer to distribution licensee
Short Voltage Interruptions	Number of events per year as per Table- 8	Rs.50/- per instance for which voltage dips or swell was beyond the specified limits	Distribution Licensee to each consumer connected on the feeder/ designated DTR. These compensations shall be cumulative for each violation.
Long Supply Voltage Interruptions	SAIDI in Minutes per Customer as per Table- 9	5 paisa/min/kW of contract demand for which SAIDI was beyond the specified limits	
Long Supply Voltage Interruptions	SAIFI in interruption per customer as per Table- 9	Rs.50/- per interruption for which SAIFI was beyond the specified limits	

Provided that such compensation as given in above Table-10 shall not be claimed in ARR by distribution licensee and further the compensation received by the distribution licensee from the designated customers shall be utilized only on the measures taken to improve power quality such as installation of filters, controllers etc.;

CHAPTER – 6

MISCELLANEOUS PROVISIONS

20. Power to Relax. The Commission, for reasons to be recorded in writing, may relax any of the provisions of these regulations on its own motion or on an application made before it by an interested person.

20. Power to Remove Difficulty: If any difficulty arises in giving effect to the provisions of these regulations, the Commission may, by order, make such provision not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these regulations.

Secretary

Annexure-VIII

FORUM OF REGULATORS (FOR)
64^{th} Meeting

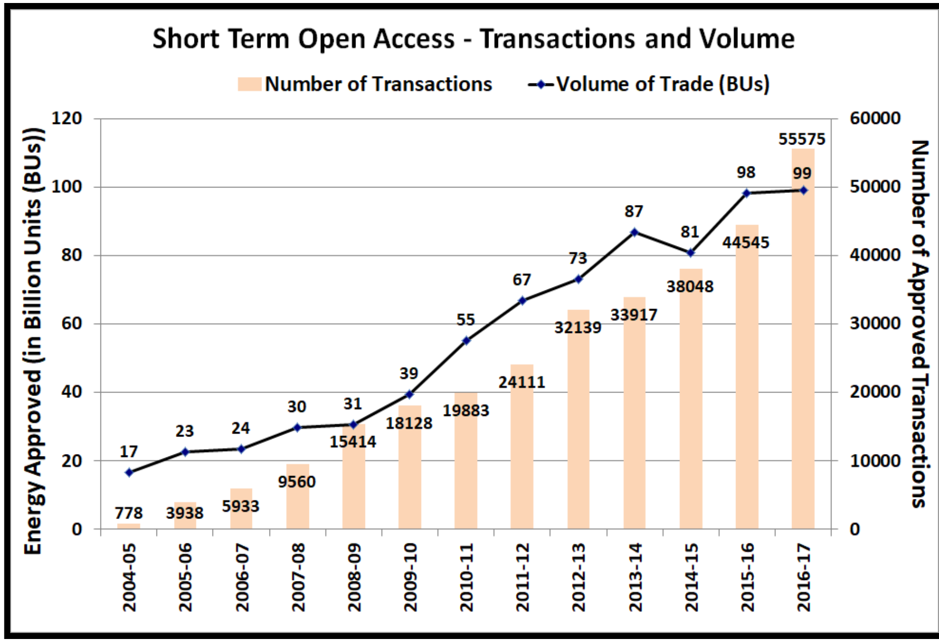
Ranchi, Jharkhand
24^{th} August, 2018

National Open Access Registry (NOAR) - Brief

Need for Registry

- Inter-State Open Access Participation
  - Annual ~ 50,000 Nos. Transactions; ~ 105 BU Energy

- Administering Market at Inter-State level
  - Common interface
  - Security and Reliability
  - Speed and Scale
  - Transparency and Accuracy
  - Information System
  - Market monitoring



- Future
  - Distributed Renewables, Electric Vehicles, Storage, Aggregators, Cross Border Transactions

Background

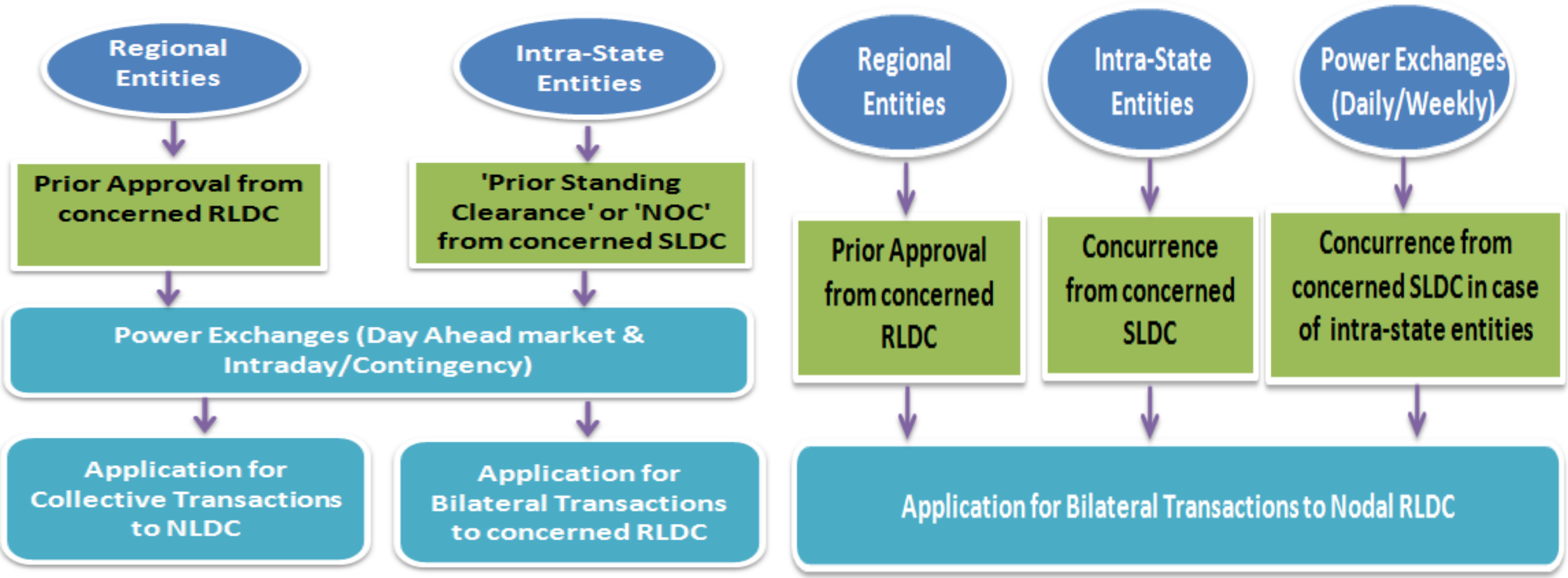
- CERC order - 08th April, 2015
  - Extended Market Session on Power Exchanges
  - Creation of National Open Access Registry (NOAR)

- CERC Central Advisory Committee(CAC) – 20th Meeting, 18th April, 2016
  - Deliberations on need for an electronic platform for facilitating Open Access

- CERC Staff Paper on NOAR - 25th November, 2016
  - Focus on short-term open access
  - Integrated IT based system accessible to stakeholders

- Draft CERC (Open Access in inter-State Transmission) (Fifth Amendment) Regulations – 08th August, 2018
  - Regulatory Framework for Implementation of NOAR
  - Single Window Technological Solution
  - Improvements in Efficiency and Transparency

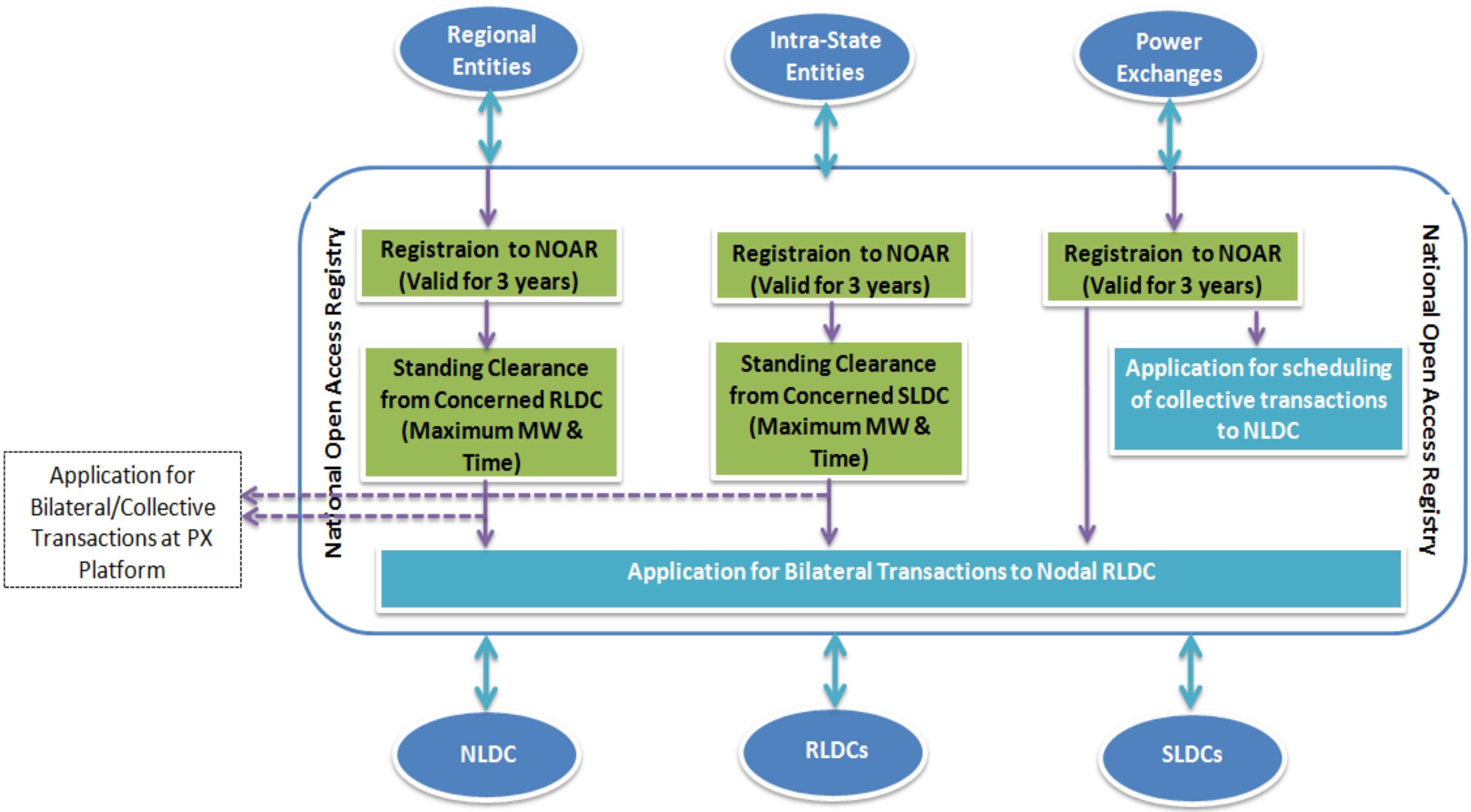
Existing System



Prior Standing Clearance or NOC

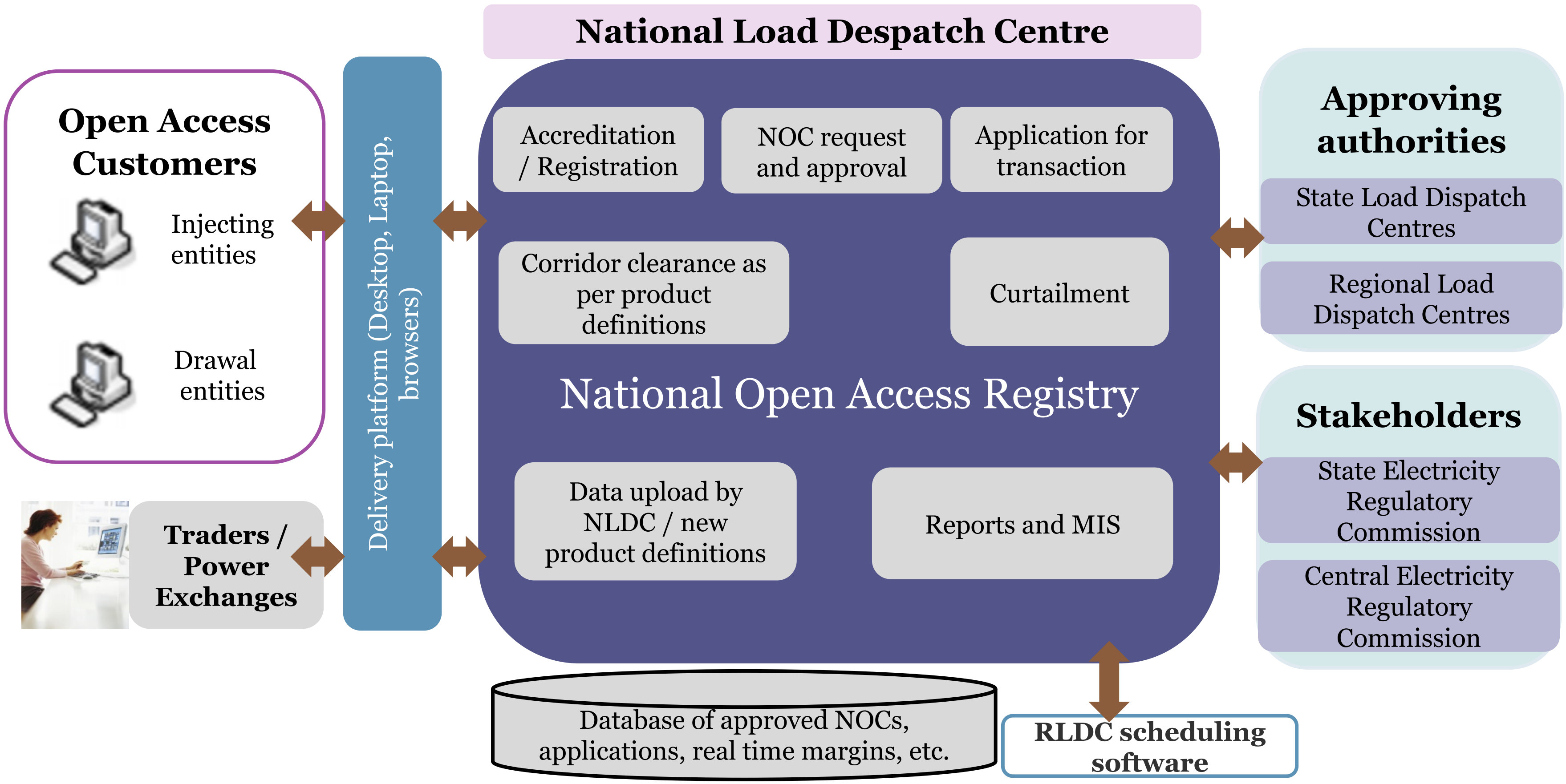
Concurrence

Proposed System through NOAR



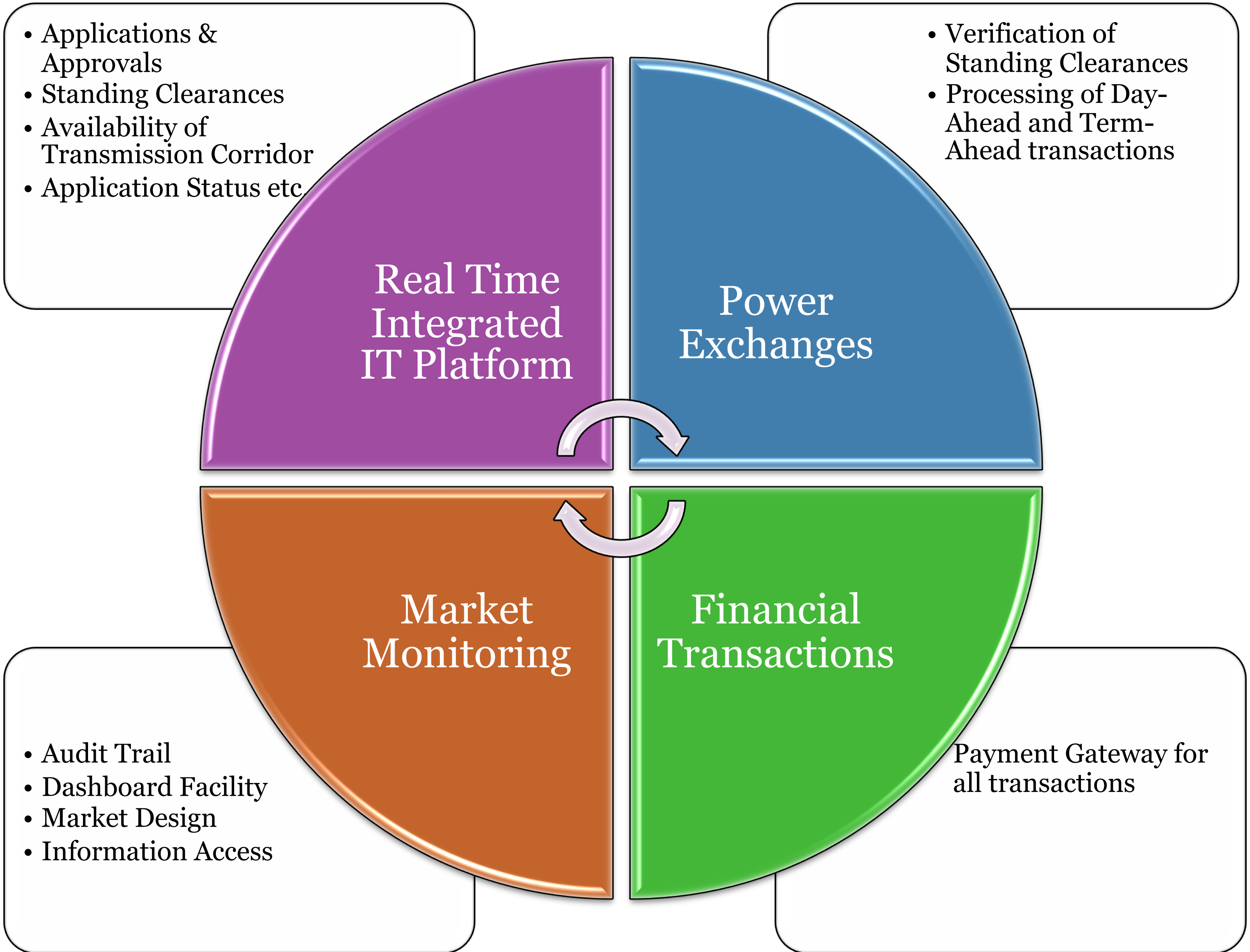
High level Overview of NOAR

- Interactions with multiple stakeholders

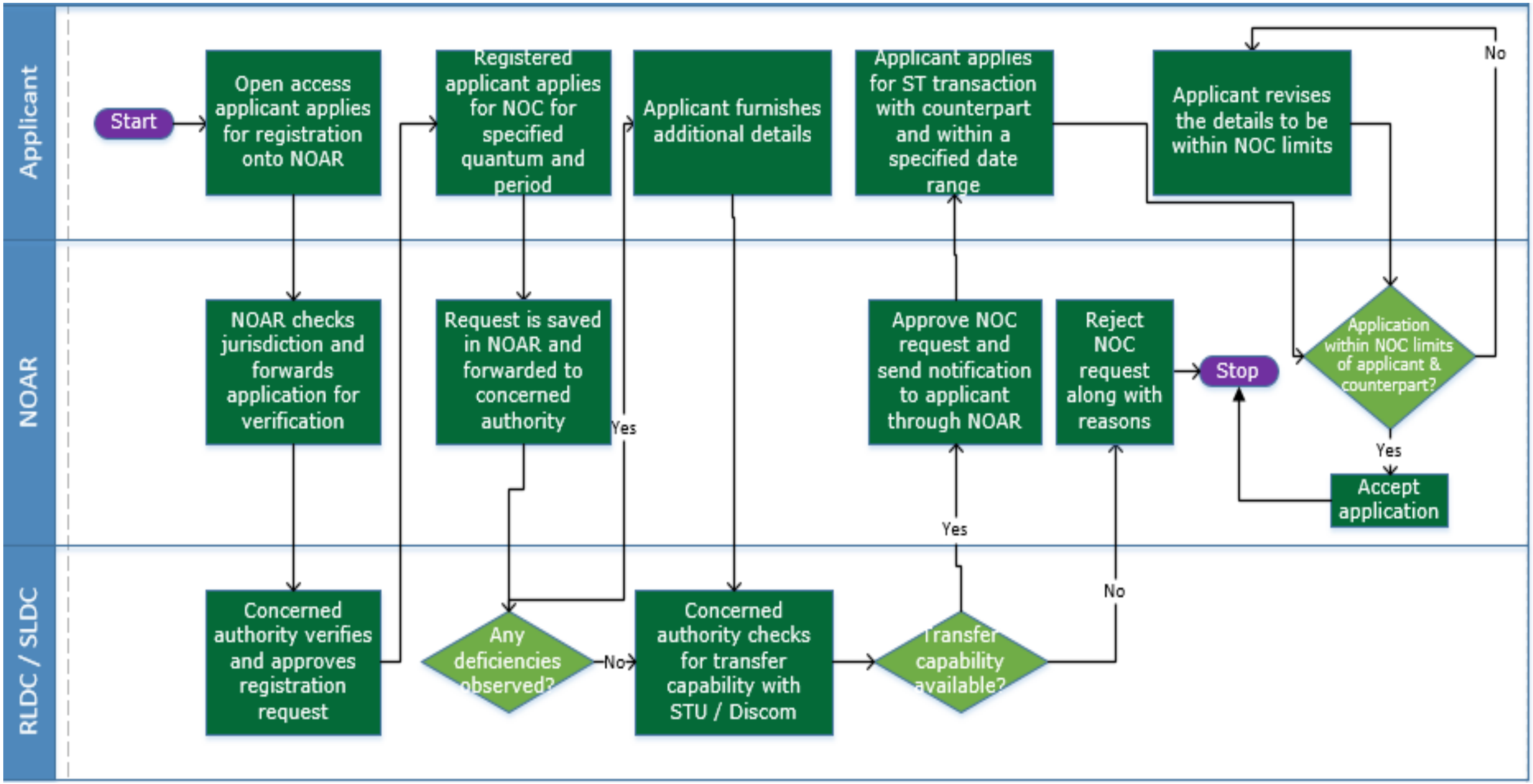


- National Load Despatch Centre will be the responsible Authority for integrated operations of the NOAR
- NOAR will interact with multiple stakeholders and have multiple data export / import points

Key Objectives

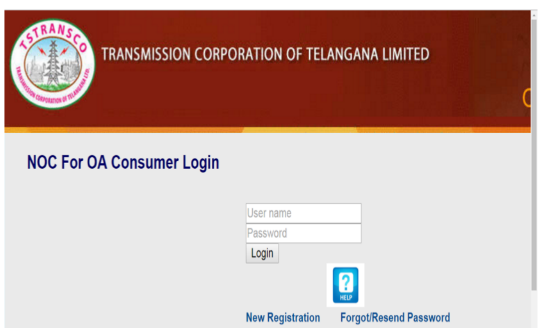


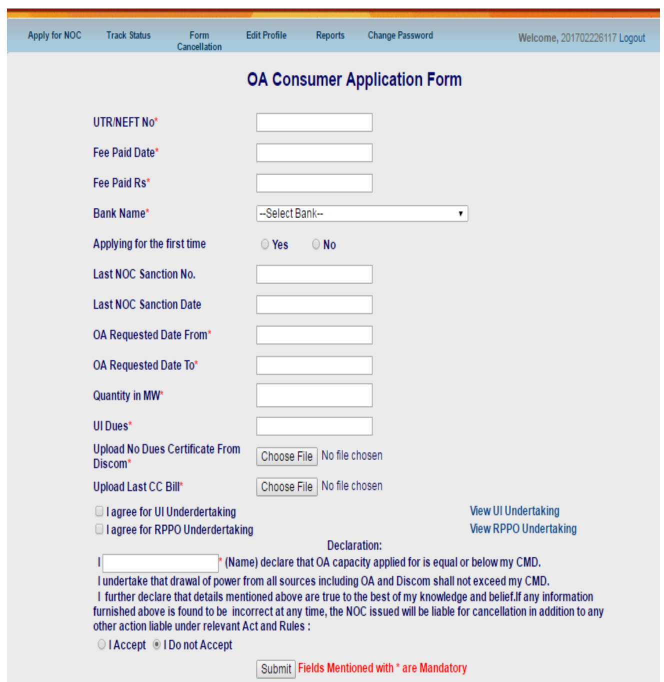
High level overview of NOAR
Flowchart from Registration to Application for transaction

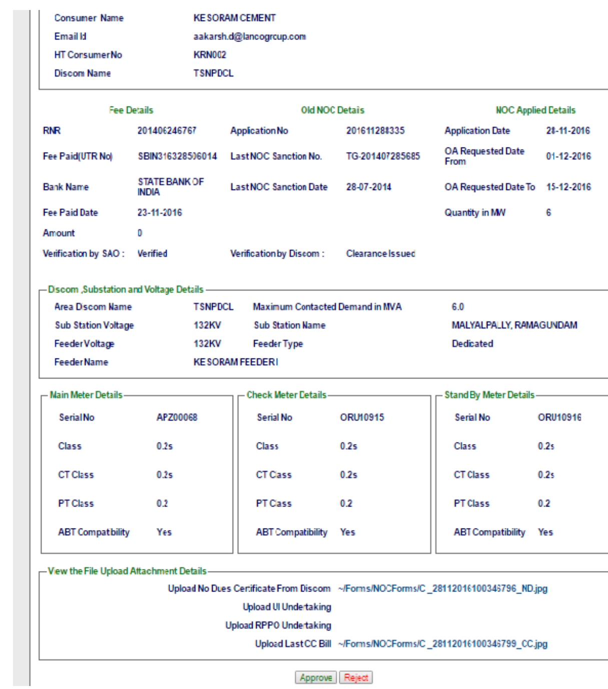


States at the Forefront of Technology
Telangana SLDC

- Developed a software for processing of Open Access Applications from Consumers/ Generators through Power Exchange
- Around 100 NOC's are being issued every month using this application in just a single click.



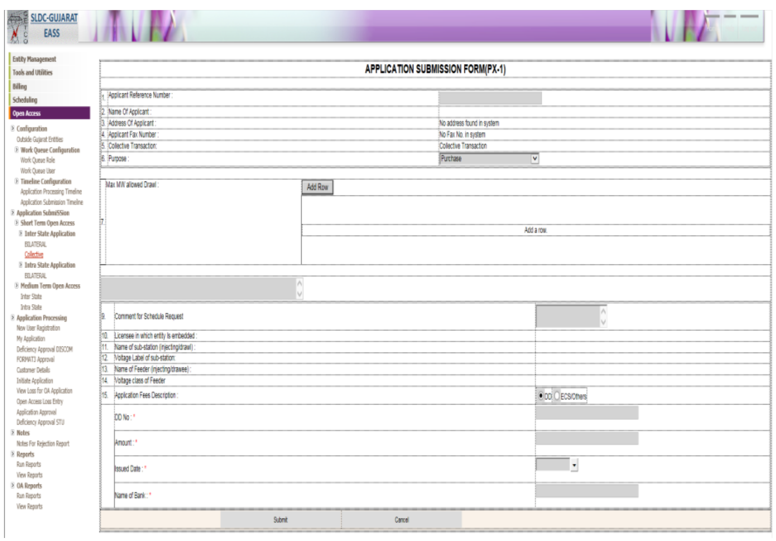


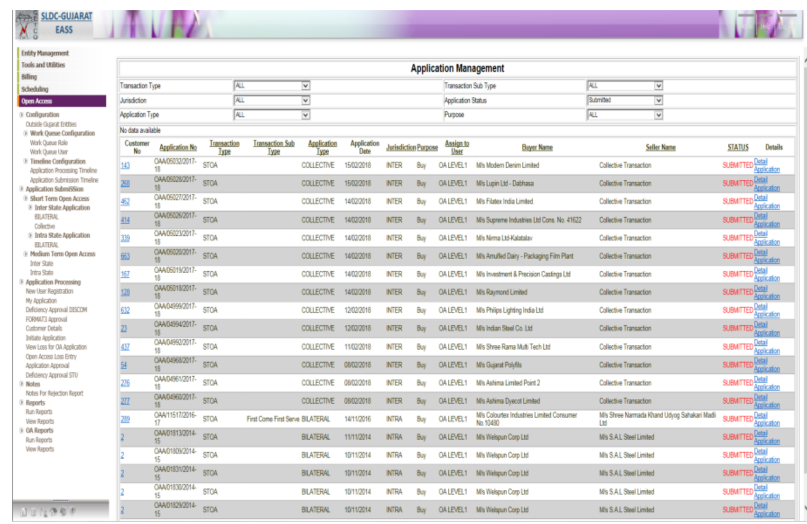


States at the Forefront of Technology

Gujarat SLDC

- Web based EASS software
  - End to End web based solution for scheduling, open access and energy accounting with AMR facility
  - USER can access and submit the data from any where across the globe
  - Auto confirmation mail for submission and approval of data
  - Minimum human intervention
  - Web service for back to back data transfer from RLDC to SLDC





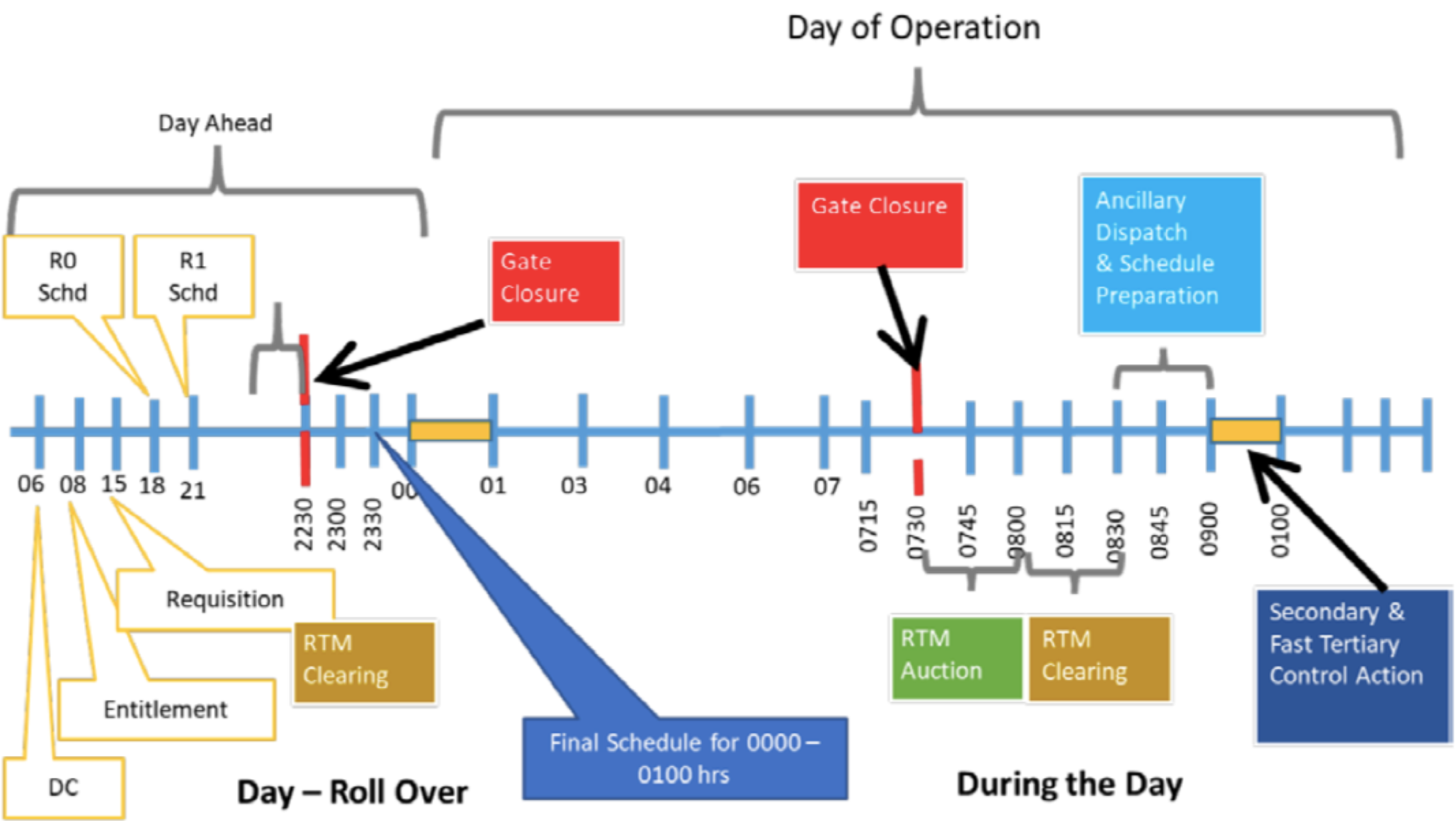
Real Time Market

CERC Staff Paper on "Redesigning Real Time Electricity Markets in India, 25th July 2018

Market Operation – Framework			
Categories of Market	**Day Ahead Market (DAM)**	**Real Time Market (RTM)**	**System Imbalance/Ancillary Services Market**
Purpose	Energy Trade	Energy Trade	Inadvertent deviation management
Market Operation – India			
Current	DA (self-scheduling + Power Exchange (PX))	Deviation settlement Mechanism (DSM) + Ancillary Services (AS) + Intra-Day (PX) + Re-Scheduling (4 time blocks prior to dispatch)+ Intra-day contingency	
Desirable	DA (self-scheduling + PX)	Real Time Market (Hourly), with gate closure	DSM + AS

Gate - Closure

CERC Staff Paper on "Redesigning Real Time Electricity Markets in India, 25th July 2018



Present Status of NOAR Implementation

- Discussions and deliberations on various processes of NOAR
  - FOLD Meeting
  - Feedback from RLDCs/NLDC on processes and functionalities
- Preparation of Process Maps and Information Flows
  - Support being provided by CERC
- Infrastructure Requirement
  - IT Systems Study under progress
- Regulatory Framework under consultation process
  - Open Access 05th Amendment
- Procedures under NOAR under formulation

Thank You!