February, 2018

USER DOCUMENTATION

Version 1.0.1

Revenue and Tariff Analysis for Electric Utilities of Andhra Pradesh (RATE-AP) Model

Prayas (Energy Group)

Prayas (Energy Group)

About Prayas

Prayas (Initiatives in Health, Energy, Learning and Parenthood) is a non-Governmental, non-profit organization based in Pune, India. Members of Prayas are professionals working to protect and promote the public interest in general, and interests of the disadvantaged sections of the society, in particular. Prayas (Energy Group) works on theoretical, conceptual, regulatory and policy issues in the energy and electricity sectors. Our activities cover research and intervention in policy and regulatory areas, as well as training, awareness, and support to civil society groups. Prayas (Energy Group) has contributed in the energy sector policy development as part of several official committees constituted by Ministries and Planning Commission. Prayas is registered as SIRO (Scientific and Industrial Research Organization) with Department of Scientific and Industrial Research, Ministry of Science and Technology, Government of India.

Prayas (Energy Group)

Unit III A & III B, Devgiri,

Joshi Railway Museum Lane, Kothrud

Pune 411 038. Maharashtra Phone: 020 - 2542 0720

Email: energy@prayaspune.org; Website: http://www.prayaspune.org/peg

Authors

Ann Josey, Manabika Mandal, Srihari Dukkipati

Acknowledgements

RATE–AP was developed with the valuable support of the Andhra Pradesh Electricity Regulatory Commission (APERC). We are grateful to Justice Bhavani Prasad, Chairperson, Dr. Pervela Raghu, Member, and Sri. Pendyala Rama Mohan, Member of APERC. We would especially like to thank the Commission staff, Late Sri Rama Rao, Sri PM Murali Krishna, and Sri MS Vidyasagar for their support which facilitated the process of customizing the model.

Version History

Version	Date	Remarks
1.0	January 2018	- Initial version
1.0.1	February 2018	- Improved readability - Compatible with model version 1.0.1

For Private Circulation only

Suggested citation: Prayas (Energy Group). (2018). User Documentation for RATE-AP (ver. 1.0.1)

This is the user documentation for the Revenue and Tariff for Electric Utilities of Andhra Pradesh model or RATE-AP. This document should be read in conjunction with the excel-based RATE-AP model and the presentation on the model submitted to APERC on the 29th of January, 2018. For information on the model, please contact energy@prayaspune.org.

Table of Contents

List of Figures

List of Tables

List of Screenshots from RATE-AP

1 Background and Context

The power sector faces multiple challenges including burgeoning financial losses, inefficiencies in power generation and power purchase planning and tariffs not being commensurate to costs. Additionally, emerging trends make it more difficult to ensure power sector utilities are able to provide reliable, affordable access for all. With rising cost of supply, uncertainty in demand, falling prices of renewable energy sources utility business models are at a cross-roads and it is pertinent to discuss various policy and regulatory responses to emerging trends.

Revenue and Tariff Analysis for Electric Utilities (RATE) model can be a crucial tool in this context. RATE is a dynamic, sense making model which helps understand the cumulative, order of magnitude impact of various trends, regulatory/policy decisions, especially on the finances of the utilities. The model was initially developed by Prayas (Energy Group) or PEG for the state of Maharashtra. Subsequently, PEG customised the model for Andhra Pradesh at the request of, and with inputs and assistance from, the Andhra Pradesh Electricity Regulatory Commission (APERC).

This manual provides a brief overview of the structure of the RATE model for AP, henceforth referred to as RATE-AP, and details the various functions of the model. Further, the manual also has detailed descriptions and examples of how to input and change parameters and values in the model to aid users. In order to demonstrate the utility of the model, PEG ran a few example scenarios. These scenarios, together with the associated assumptions and results, are not prescriptive and are instead meant to showcase the type and range of analyses possible with RATE-AP.

In addition to this document, a short presentation was made to the APERC on the 29th of January 2018. Together they form the reference documentation for the RATE-AP model.

2 About Revenue and Tariff Analysis for Electric Utilities (RATE)

RATE is a spread sheet based transparent model which has been developed by Prayas (Energy Group) or PEG. It is a sense making model to help policy makers and regulators get a better understanding of the impact of various possible trends, changes and policy responses. The model has provisions for disaggregated inputs for various components of utility operations. It is structured to assess impacts of changes, especially cumulative impacts of changes on key financial and performance parameters on a medium term horizon i.e-five to seven years.

In a time of uncertainty, the objective of the RATE model is to provide early warning signals for areas which need attention. Sense making based on the model can also help avoid adverse impact due to impending changes by informing adequate policy responses. RATE can be used to explore possible options for efficiency improvements and operations, evaluate the impact of innovative proposals and regulatory changes. Additionally, one of the key uses of the RATE model could be to set expectations among various actors and build consensus regarding various policy and regulatory options.

3 Key Features

Following are some of the features of RATE-AP:

a. Station-wise disaggregation of generation and costs for power procurement
b. Reconciliation of RE capacity addition with RPO targets
c. Annual order of magnitude estimates for backing down in the face of surplus
d. Options for purchase/sale in case of annual shortage/surplus
e. Separate treatment for DISCOMs in Andhra Pradesh, namely APEPDCL and APSPDCL
f. Category wise, voltage wise, sales and revenue from tariff estimates
g. Option to input tariff increase and change tariff design
h. Category wise sales migration due to Open Access, Captive from renewable and conventional generators as well as rooftop solar. It also includes estimation of revenue from charges
i. Capital expenditure estimation based on tariff regulations and Operation and Maintenance expenses estimated based on past trends.
j. All inputs are given and all results are reported on an annual basis for a five year time period.

RATE is not designed for analysis of diurnal and seasonal variations in demand and supply (such as changes in load profile due to use of energy efficient appliances, ToD tariffs or sales migration due to short term open access), which are better analysed with production cost simulation models. RATE is also not intended to replace the ARR models used by the regulatory commission or utilities, which are more accurate and relevant for periodic tariff revision. RATE-AP does not focus on transmission and hence analysis on transmission pricing and investment is not possible with the model.

Even so, RATE can offer useful insights on cost impacts and impact of financial losses to due changes in sales mix, tariff design, generation mix, backing down of contracted capacity, fuel cost escalation, and capacity addition. It is a dynamic and active tool and thus should be updated to account for latest policy and regulatory changes, price trends and sales migration on a periodic basis.

The period for the analysis is from 2016-17 to 2021-22. The model relies on historical data, existing policies, regulations and future expectations in order to determine likely future trends and design scenarios for this time period. As the model is designed to be dynamic, the time period can be extended as well.

4 Model Structure

As the Andhra Pradesh power sector has a single buyer model with the DISCOMs being allocated power, the treatment for the power procurement business and the distribution business are distinct. The energy procurement and the costs incurred as a consequence are estimated together for both DISCOMs and is then allocated to each DISCOM. This includes power procurement from Andhra Pradesh Power Generation Corporation (APGENCO), Central Sector Generating Stations (NTPC, NHPC etc.) as well as Independent Power Producers with cost-plus and competitively bid tariffs. The procured power and costs are then allocated to the DISCOMs, Southern Power Distribution Corporation of Andhra Pradesh Limited (SPDCL) and Eastern Power Distribution Corporation of Andhra Pradesh Limited (EPDCL). The sales, revenue and distribution costs for the SPDCL and EPDCL are estimated separately in the model. Thus, RATE-AP provides the Aggregate Revenue Requirement (ARR), cumulative revenue gaps for SPDCL and EPDCL separately.

4.1 Model conventions used in RATE-AP

The sheets in the model have blue, grey, and white cells. Blue cells are those which can be used by the user to input values. The input values can be escalation rates, growth rates, multipliers, or numerical values, which can be changed. Grey cells are input value cells as well, but contain historical values (values that essentially will not change in the future). White cells (and cells of any other colour) in the model contain formulae. This has been summarised in Table 1.

Table 1: Functions of different types of cells in the Model

Cell Type in Model	Function
Blue Cells	*Input Values*
Grey Cells	*Input historical values*
White Cells	*Output Values*

4.2 Brief Overview

Figure 1 depicts the structure of the model. Table 2 provides a brief overview of the various parameters and features related to the blocks depicted in the structure, and maps the blocks to sheets in RATE-AP.

Figure 1: Structure of RATE-AP

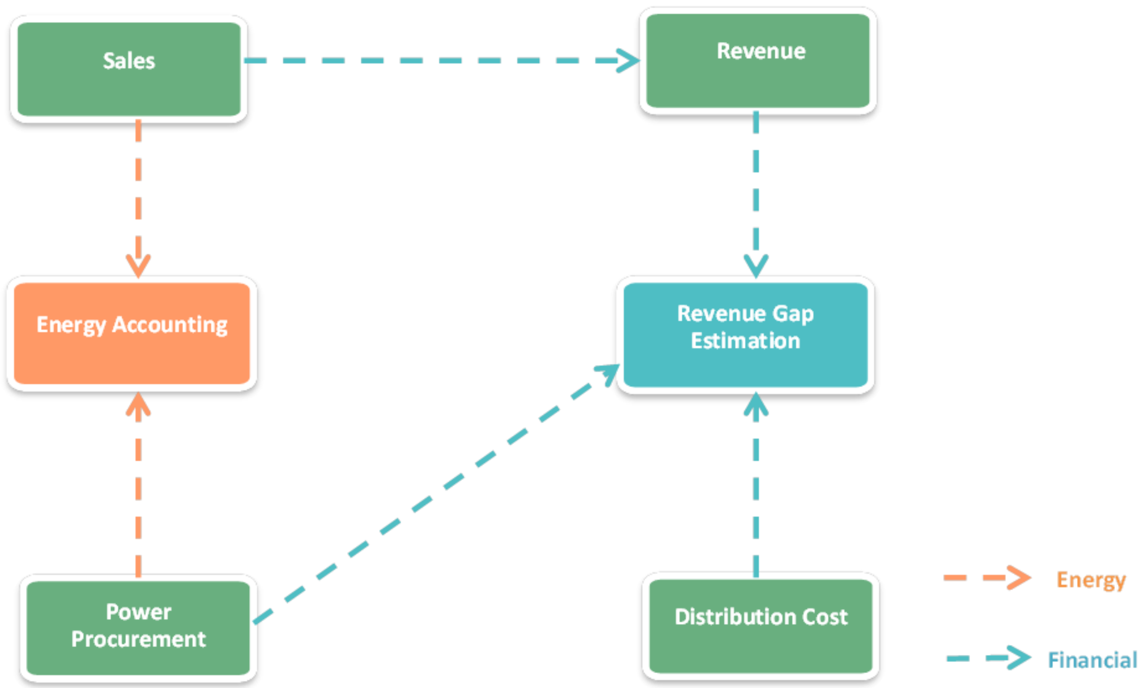


Table 2: Structure of RATE-AP

BLOCK	DESCRIPTION/PARAMETERS	Corresponding Sheets in the Model
Overview	• Index of sheets, Structure outline • Definitions and Notes	Index A| Definition and notes B| Discom Summary C| PP Summary
Sales	• Category wise, voltage wise projections • Sales migration through open access, captive and rooftop solar	S1| SP Sales and Migration E1| EP Sales and Migration S2| SP Migration Option Rates E2| EP Migration Option Rates H3| Open Access Calculator

Power Procurement	• Station-wise capacity, generation and cost • Disaggregated fuel costs • Backing down by adjustment of PLFs	P0| PP Assumptions P1| PP All P2| GenCo Thermal P3| GenCo Hydro P4| Central P5| Private P6| NCE H1| Backdown Helper H2| RPO
Energy Accounting	• Power surplus /shortage based on procurement, voltage wise losses • RPO requirement and assessment of excess/shortfall capacity addition • Sale of surplus power/ purchase of short term power	S5| SP Energy Accounting E5| EP Energy Accounting
Distribution costs	• Capital Expenditure • Operation and Maintenance • Other expenses	S4| SP Distribution Cost E4| EP Distribution Cost
Revenue and Tariffs	• Revenue from retail tariffs based on tariff projections, tariff design • Separate estimation of category wise fixed and variable costs, revenue from sales migration • Revenue gap carry forward with applicable carrying cost	S3| SP Revenue E3| EP Revenue S6| SP ARR E6| EP ARR H4| Cross Subsidy Calculator

The station-wise or unit-wise power procurement and the costs for the same are detailed in the sheets named "P2| Genco Thermal", "P3| PP Genco Hydro", "P4| PP Central", "P5| PP Private" and "P6| PP NCE". This is described in greater detail in sections 5.1 to 5.3.

The estimation of future sales for SPDCL and EPDCL after considering sales growth rates, sales migration via open access and captive options are carried out in sheets named “S1 | SP Sales” and Migration for SPDCL and “E1 | EP Sales and Migration” for EPDCL. The sales for small, medium and large consumers in each category is projected separately based on assumed growth rates and assumed migration of sales in each year. The assumptions for Cross Subsidy Surcharge (CSS), additional surcharge, wheeling charges and concessions provided for renewable energy open access can be specified in the sheets named “S2 | SP Migration Option Rates” for SPDCL and “E2l EP Migration Option Rates” for EPDCL. Based on the charges specified, the revenue earned due to sales migration charges is also estimated in the Sales and Migration sheets. This is described in greater detail in section 5.4.4.

The energy accounting sheets, named “S5l SP Energy Accounting” for SPDCL and “E5l EP Energy Accounting” for EPDCL perform multiple functions in the model as detailed below:

a. **Estimation of total energy requirement give T&D losses**: Based on the sales considered, the energy requirement is estimated given inputs for inter-state and intra-state transmission losses and applicable distribution losses.
b. **Surplus/Shortages and their treatment**: Given the energy requirement and the apportioned power procurement for EPDCL and SPDCL, the energy accounting sheets estimate the energy surplus which needs to be addressed via the sale of surplus power, the short term power purchase needed to address shortages or the load shedding needed in the absence of such purchases. Based on the considered quantum and assumed price of purchase or sale through trading licensees, power exchanges or settlements via the DSM mechanism, the revenue from sale of surplus or the cost of short term power purchase is also estimated. Surplus power can also be addressed through backing down of thermal power plants and this is done by adjusting PLFs in the power procurement sheets. This is described in greater detail in sections 5.3.2 and 5.3.3.
c. **RPO compliance and its impact**: Based on the energy requirement or consumption estimated and the procurement of renewable energy power estimated in “P6l PP NCE” sheets, RATE-AP also calculates additional REC purchase requirement and cost of RPO compliance.
d. **Estimation of transmission costs**: The applicable transmission costs are estimated based on the energy wheeled using the intra-state and inter-state transmission network and an assumed per unit intra-state or inter-state transmission charge, which can be specified in this sheet.

The energy accounting sheet is described in greater detail in Section 5.5.

The distribution costs, notably the capital expenses and the operation and maintenance expenses are estimated in the sheet named "S4l SP Distribution Cost" for SPDCL and "E4l EP Distribution Cost" for EPDCL. The estimation is based on APERC Regulations and historical trends. This is described in detail in Section 5.6

Distribution companies are able to recover revenue from various sources to meet their growing expenses. The primary source of revenue is the revenue from retail tariffs charged to consumers of the DISCOM. In the sheets named "S3l SP Revenue" for SPDCL and "E3l EP Revenue" for EPDCL the user can estimate:

a. **Revenue from retail tariffs**: The category-wise average tariffs for small, medium and large consumers can be specified for the base and subsequent years. Adjustments to the average category-wise tariffs can also be used to change the cross subsidy design. Based on the sales and the average tariff, category-wise revenue from retail tariffs is estimated. In addition, users can specify the proportion of revenue recovered from fixed charges and energy charges whose adjustment can also change the tariff design.
b. **Non-tariff income**: There is provision for estimating non-tariff incomes and these are projected based on growth rates entered by the user
c. **Revenue from subsidies**: Revenue from government subsidy is an input for each DISCOM and can be specified on an annual basis.
d. **Revenue gaps and associated carrying costs**: Revenue from retail tariffs, subsidies and non-tariff income is estimated in various "revenue" sheets. This is added to the revenue from sales migration estimated in the Sales and Migration sheets and the revenue from sale of surplus power estimated in the Energy Accounting sheets to estimate the total revenue recovered by the DISCOM. Based on distribution costs, power procurement costs (including short-term power purchase costs) and transmission costs from the relevant sheets, the total expenses of the DISCOM are also calculated. The annual revenue gap or surplus is then estimated as a difference between the revenue from various sources and the total expenses. Revenue gaps are carried forward for recovery in the subsequent years along with the applicable carrying cost, based on the interest rate specified by the user. The cumulative revenue gap is estimated along with carrying cost on an annual basis.

More details on the structure of the model as well as details on how to use RATE-AP are provided in section 5.

4.3 Helper Sheets: What are they?

As there are multiple disaggregated inputs that the user needs to specify for each of the blocks, helper sheets are provided in RATE. These sheets named "H1| Backdown Helper", "H2| RPO", "H3| Open Access Calculator" and "H4| Cross Subsidy Calculator" are disconnected from the model and are there to assist users in providing multiple inputs for the model. Given below is a brief description of each of these helpers:

a. **Backdown Helper**: In case there is a significant surplus power as per the energy accounting sheet, the user may choose to back down plants by adjusting the average annual plant load factors (PLFs) which are inputs in the power procurement sheets. The "Backdown Helper" sheet aids the user in adjusting the PLFs based on the merit order stack until the surplus is down to the desirable level. Please see Section 5.3.3 for more details.
b. **RPO or RE Capacity Addition**: This helper assists the user in deciding the annual capacity addition based on renewable purchase obligation (RPO) trajectories or policy targets (such as the state-wise targets for capacity addition suggested by MNRE to meet the national goal of adding 175 GW of RE power by 2022). Please see Section 5.3.6 for more details.
c. **Open Access Calculator**: More accurately, this is a sales migration calculator. RATE-AP has options for migration of sales through multiple avenues such as open access from renewable/conventional power generators, migration to captive plants which are located at the site of consumption or away from it or migration to rooftop solar options. The proportion of sales migration in each category needs to be filled by the user for every year. This calculator can help the user specify the total sales migration every year on a cumulative basis which can be used to decide the proportion of the total migration through each of these avenues. Please see Section 5.4.5 for more details.
d. **Cross Subsidy Calculator**: Category-wise tariff changes are input by the user in the model. In order to facilitate changes in tariff design, this calculator translates the category-wise tariff changes into the proportion of the average cost of supply being recovered from each category. This in turn can help the user in changing the cross subsidy model or evaluating the impact of tariff changes on the current cross subsidy model. Please see Section 5.7.2 for more details.

4.4 Summary Sheets in RATE-AP

RATE-AP has various summary sheets where results are collated and important parameters are documented, which can be used to assess impacts of the changes modelled. These summary sheets are described below:

a. **Aggregate Revenue Requirement (ARR)**: Akin to the ARR Summary used by the APERC and DISCOMs during the tariff determination process, the sheets named "E6| EP ARR" for EPDCL and “S6| SP ARR” for SPDCL provide summaries of itemized expenses and revenues, and the estimated revenue gap.

b. **Power Procurement**: There are two summary sheets for power procurement. The first is “P1 |PP All” which has a station wise summary of capacity, net generation, fixed and variable costs for all generators with which the DISCOMs has long-term contracts. The second is the “C |PP Summary” sheet which provides a more concise summary focusing on ownership-wise (state, central, private etc.), fuel/technology-wise breakup of power procurement, average PLFs and associated costs. This sheet also provides estimates for backing down and fixed costs payments for backed down capacity. The allocation of power procured to each of the DISCOMs based on an assumed share is also done in this sheet.

c. **DISCOM Summary:** The “B|DISCOM Summary” sheet provides key statistics for both the DISCOMs including sales, sales migration, various costs and revenues, the average cost of supply, average power procurement cost and the average billing rate.

5 Using RATE-AP: Detailed Description of the model

Section 4 provides a brief outline of the model. In this section, a detailed description of each block with instructions on how to enter inputs has been provided along with examples to explain how the model works. The descriptions map to the major blocks described in Table 2.

5.1 Entering power procurement details

Power procurement costs are treated differently for different types of contracts. Generators can have a cost-plus regulated tariff where the ERC fixes the tariff and the generators earn a fixed rate of return. These plants usually have a two-part tariff: a variable cost which is a function of the net generation of the plant billed on a per unit rate and a fixed cost which is a lump sum annual payment made on the basis of availability of the capacity irrespective of generation.

In each of the power procurement sheets, inputs are entered in the left-to-right order of contracted capacity (MW), availability and net PLF (%), fixed costs (Rs/kW/year) and variable costs (Rs/kWh) for each station for each year.

The net generation is estimated using capacity and net PLF. The user also has to specify average annual availability (%) and the normative availability of the station. If the availability is lower than the normative availability, the fixed cost is adjusted on a pro-rata basis. If the PLFs of the plant are higher than the actual PLFs, then a PLF based incentive is provided to the generators. The incentive is obtained at a rate as determined by the SERC/CERC for the efficiency gain over and above the norm (as input in the “ERC norms” section in the “P0|PP Assumptions” sheet).

The user specifies the fixed and variable costs for the base year along with an annual escalation rate to project fixed and variable charges for future years (there are exceptions to this, particularly for competitively bid projects, as is explained in the rest of this section). The fixed cost payments made for contracted capacity are input in units of Rs/kW/year. The unit of measurement of fixed cost payments in Andhra Pradesh, as stated in regulatory formats is generally in Rupees crores. The input value for fixed cost payments in the model is arrived at by dividing this amount by the contracted capacity. Variable cost payments are input in units of Rs/kWh. The variable cost of power purchase is calculated based on the net generation multiplied with the per unit variable cost (input value).

Subsequent to accounting for fixed and variable costs, provisions have been made in the model for additional costs for each generating station on a per unit basis. This cost can be input by the user to account for any additional costs impact as a consequence of ERC review orders, APTEL judgments or High Court/ Supreme Court judgments. It could also be used as a way to adjust for cost impacts due to parameters currently not considered in the model

The state sector thermal generators as specified in the sheet titled "P2| Genco Thermal" and the central sector generators in the sheet "P4| Central" are treated similarly in the model. Hydro generating stations, listed in the "P3| Genco Hydro" sheet, have a single part tariff in the form of only fixed cost payments. The user needs to specify the design energy rate for hydro projects which can be used to guide the annual inputs for PLFs and is also used to estimate availability based incentives. Even though the treatment of nuclear power in the model is the same as central generating stations, only variable charges are input since details of the fixed and variable cost break-up are not available for these projects.

This treatment of generation and cost estimation is the same for cost plus private sector thermal projects specified in the top section of the sheet named "P5| Private". The second section of the sheet "P5| Private" (titled "Competitively Bid Projects") contains details of competitively bid projects whose cost determination is done differently than "cost-plus" projects. The cost inputs are fixed and variable costs classified as fuel costs, fuel handling costs, and transportation costs. These costs parameters are further segregated as "escalable parameters" and "non-escalable parameters" which are based on the specifications of the Power Purchase Agreement (PPA) for the project. The year-wise winning-bid information are input in the section titled "Winning Bid Information". Each parameter has an escalation rate column (marked in blue), which can be changed by the user for all escalable factors. Summary of these input values can be found in the sections titled "Calculation of Escalable Parameters", which are then used to compute the final fixed and variable costs for competitively bid projects.

Contracted renewable capacity (for wind, solar, biomass and bagasse) is listed in the "P6| NCE" sheet according to the technology adopted. Year wise capacity addition as well as tariffs for the capacity added in each year can be input by the user for wind and solar sources. There is greater uncertainty in movement of prices for these technologies over the years, and hence the facility to input the tariffs separately for capacity addition in each year has been provided. Capacity can be added as per RPO requirement or the policy mandate for the DISCOMs. As per the power purchase agreements, a single part tariff is arrived at for renewable generating capacity which is levelised and fixed over a period of time. Tariffs can be input by the user for existing capacity and separately for each of the future years. Based on the specified capacity, PLF, the consequent net generation and the input levelised tariff for the year, the overall costs and subsequently the average levelised costs are calculated.

5.2 Global assumptions for escalation rates for fixed, variable costs

The escalation rates assumed by the user for fixed and variable cost are dependent on variety of factors specified in the "P0| PP Assumptions" sheet (See Screenshot 1).

Screenshot 1: Power Purchase Assumptions

Power purchase Assumptions		
First Year in Model	**2018**	FY18
CERC Annual Escalation Rates		
Component	**Sub-component**	**Assumptions used in the tool**
Escalation rate for domestic coal		2%
Escalation rate for domestic gas		1%
Escalation rate for imported coal sub-components	Coal	-3%
	Transportation	-5%
	Inland Handling	5%
Inland Transportation of Coal	Upto 100 km	7%
	Upto 500 km	7%
	Upto 1000 km	7%
	Upto 2000 km	6%
	> 2000 km	6%
Inland Transportation of Gas		0%
Escalation rate for imported gas sub-components	Gas	-2%
	Transportation	-7%
	Inland Handling	5%
Indexed capacity charge component (O&M escalation)		5%
Indexed energy charge component (captive fuel source)		4%
Discount rate to be used for bid evaluation		not used
Annual escalation of dollar		3%
Capacity Charge escalation for depreciated plants		2%

Important assumptions, which can be adjusted in the model through the PP Assumptions sheet, are listed in Table 3. Note: Cell numbers provided in Table 3 are subject to change.

Table 3: Assumptions for power purchase in "PP Assumptions" sheet

Variable Name (Reference Cell Number)	Effect of change in value
Fuel Escalation Rates (D7:D20)	These cells are inputs for escalation rates for fuel and transportation as prescribed by CERC annually. These values feed into the Private sheet as part of the parameters used to determine competitively bid and contracted power projects.
Fixed_Cost_Esc (D21)	This component determines the annual escalation rate of the capacity charges paid to each non-renewable generating station. A change in the input value automatically changes the escalation rate for all non-renewable generating stations.
Fixed_Cost_Esc_Post_Loan_ Repayment (D25)	There is provision in the model to choose a different annual escalation rate for capacity charges of power plants which are older in vintage and have already made considerable payments towards depreciation of the plant.
Variable_Cost_Esc (D22)	This component determines the annual escalation rate of the energy -charges paid to each non-renewable generating station. A change in the input value automatically changes the escalation rate for all non-renewable generating stations.
Availability_Norm_SERC/CERC, PLF_Norm_SERC/CERC, PLF_Incentive_CERC/SERC, (D27:D33)	These inputs are based on state ERC norms which provide incentives for generation efficiency.
Dollar_Escalation_Rate (D24), Dollar_Rate_Table (D37:L37)	The variable named Dollar_Rate_Table refers to the dollar-rupee exchange rates over the years. Future year rates are determined based on the input escalation rate. However, escalation rate can be overwritten by inputting yearly values in the Dollar_Rate_Table.
Inter_DISCOM_purchase_cost (D41)	When one DISCOM is energy surplus and the other has deficit, power is adjusted between DISCOMs. The The rate of sale of "Inter-DISCOM purchases" is set at Rs. 4.08/kWh and can be changed as per the users' assumptions.
APGENCO_Share (D43), TSGENCO_Share (E43)	The user can choose to allocate the contracted share of AP DISCOMs in the AP and TS GENCO capacity. The default input value is as per the Reorganisation Act, 2014. If share of AP GENCO capacity is set to 100% and TS GENCO capacity is set to 0%, it means that Andhra Pradesh contracts full generating capacity within the state geographical boundary and contracts no capacity from Telangana

	GENCO stations.
SPDCL_Share (D45:L45), EPDCL_Share (D46:L46)	The user can choose the ratio of the power purchase that is allocated to each DISCOM, each year.

5.3 Demonstrative examples for changing power procurement inputs

This section has specific examples of some inputs which can be changed by the user while creating scenarios. The resultant impact due to input changes and how it can be potentially used is also discussed here.

5.3.1 Adding a new station

Each sheet relating to power purchase has an empty row before the row containing the aggregate totals or sub-totals. In order to add a new generating station to any of the lists, the user has to ensure that they insert a new row above the empty row and fill in the details of the new contracted capacity. This will ensure that the totals include the newly inserted generator and enable easily adding more stations in the future. Nevertheless, it is a good practice to ensure that data for all stations in each column is added up in the "totals" row (including the data added for the new entry). This is illustrated in Screenshot 2.

Screenshot 2: Adding a new station

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2												
3	Station/ Unit	Fuel Type	In-state/ Out-of-state	Capacity - AP Share (MW)								
4				FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
5	NTPC-(SR) Ramagundam I & II	Coal	Out-of-state	256	258	313	313	313	313	313	313	313
6	NTPC-(SR) Stage – Ramagundam- III	Coal	Out-of-state	64	65	78	78	78	78	78	78	78
7	NTPC-Talcher-II	Coal	Out-of-state	157	152	184	184	184	184	184	184	184
8	NTPC Simhadri Stage I	Coal	In-state	381	381	461	461	461	461	461	461	461
9	NTPC Simhadri Stage II	Coal	In-state	165	175	212	212	212	212	212	212	212
10	Vallur (JV) NTPC with TANGEDCO	Coal	Out-of-state	68	84	102	102	102	102	102	102	102
11	NTPC-Kudigi	Coal	Out-of-state	0	0	201	201	201	201	201	201	201
12	Bundled Power under JNNSM	Coal	Out-of-state			39	39	39	39	39	39	39
13	NTPC Pudimadaka (400 MW)	Coal	In-state									
14												
15	NTPC Total	Coal		1091	1115	1591	1591	1591	1591	1591	1591	1591
16	NLC TS II Stage-I	Lignite	Out-of-state	45	44	53	53	53	53	53	53	53
17	NLC TS II Stage-II	Lignite	Out-of-state	79	78	94	94	94	94	94	94	94
18	NLC-TNPL Tuticorin	Lignite	Out-of-state	0	0	118	118	118	118	118	118	118
19	Sirkali (92 MW)	Coal	Out-of-state									
20												
21	NLC Total	Lignite		124	122	265	265	265	265	265	265	265
22	NPC-MAPS	Nuclear	Out-of-state	17	17	20	20	20	20	20	20	20
23	NPC-Kaiga 1 & 2	Nuclear	Out-of-state	53	52	63	63	63	63	63	63	63
24	NPC-Kaiga 3 & 4	Nuclear	Out-of-state	54	55	66	66	66	66	66	66	66
25	Kalpakkam (50 MW)	Nuclear	Out-of-state									
26												
27	NPC Total	Nuclear		124	123	149	149	149	149	149	149	149

P3| GenCo Hydro | P4| Central | P5| Private | H2| RPO | P6| NCE | S1| SP Sales and Migration | S2| SP Migration Option Rate

In order to add a new NTPC station, the user would have to add a row before row 14 and fill up the details for the station (contracted capacity, PLF, availability, fixed Costs, Variable costs, etc.). Then, the station needs to be included in the summary calculations. This is done by inserting a row in the 'P1| PP All' sheet as shown in Screenshot 3. For the new NTPC station added in this example, a new row needs to be inserted above row 42 in the 'P1| PP All' sheet and the formulas from row 41 need to be dragged down to the newly inserted row.

Screenshot 3: Adding a new station in power purchase summary

39	Central	NTPC-Kudigi	Coal	Central	Out-of-state	0	0	201	201	201	201	201
40		Bundled Power under JNNSM	Coal	Central	Out-of-state	0	0	39	39	39	39	39
41		NTPC Pudimadaka (400 MW)	Coal	Central	Out-of-state	0	0	0	0	0	0	0
42		NLC TS II Stage-I	Lignite	Central	Out-of-state	45	44	53	53	53	53	53
43		NLC TS II Stage-II	Lignite	Central	Out-of-state	79	78	94	94	94	94	94
44		NLC-TNPL Tuticorin	Lignite	Central	Out-of-state	0	0	118	118	118	118	118
45		Sirkali (92 MW)	Coal	Central	Out-of-state	0	0	0	0	0	0	0
46		NPC-MAPS	Nuclear	Central	Out-of-state	17	17	20	20	20	20	20

RATE | Index | A| Definition and Notes | B| Discom Summary | C| PP Summary | H1| Backdown Helper | P0| PP Assumptions | P1| PP All | P2| Ge

5.3.2 Changing PLF

As seen in Screenshot 2, the user can input the capacity in MW for each station. The net generation is calculated based on the capacity and the PLFs input by the user. PLFs can be modified to either simulate backing down or increase generation from a station. This is shown through an example in Screenshot 4 and Screenshot 5. Row 8 in the "P2| Genco Thermal" sheet has details for Rayalseema Stage II. If the PLF for the year FY20 is changed from 50% to 80%, it can be seen that the net generation changes from 848 MUs to 1357 MUs.

Screenshot 4: Net generation of Rayalseema-II with 50% PLF

	A	B	C	Z	AA	AB	AC	AD	AS	AT	AU	AV	AW	AX	AY
1	प्रयास Prayas (Energy Group) Unit	Fuel	Date of Commercial Operation (COD)	Net PLF (%)					Net Generation (MUs or GWh) [Capacity * Net PLF * 8.76]						
2				FY16	FY17	FY18	FY19	FY20	FY16	FY17	FY18	FY19	FY20	FY21	FY22
6	NTTPS-IV	Coal	28.1.2010	62%	80%	50%	80%	50%	1255	1616	1010	1616	1010	1616	1616
7	Rayalaseema-I	Coal	U1- 31.3.1994 U2-25.2.1995	63%	55%	50%	50%	50%	1071	933	848	848	848	848	1357
8	Rayalaseema-II	Coal	U1- 12.8.2007 U2-29.3.2008	69%	80%	50%	50%	50%	1177	1357	848	848	848	848	1357
9	Rayalaseema-III	Coal	10.2.2011	66%	80%	50%	50%	50%	557	679	424	424	424	424	679
10	Rayalaseema-IV	Coal	01-Oct-17	0%	0%	50%	50%	50%	0	0	2628	2628	2628	2628	3416
11	Sanjeevaiah I	Coal	01-Mar-14	40%	40%	80%	80%	80%	2798	2798	5606	5606	5606	5606	5606
12	Sanjeevaiah II	Coal	01-Dec-14	26%	26%	80%	80%	80%	1807	1807	5606	5606	5606	5606	5606

H1| Backdown Helper | P0| PP Assumptions | P1| PP All | P2| GenCo Thermal | P3| GenCo Hydro | P4| Central | P5| Private

Screenshot 5: Net generation of Rayalseema-II with 80% PLF

Unit	Fuel	Date of Commercial Operation (COD)	Net PLF (%)					Net Generation (MUs or GWh) [Capacity * Net PLF * 8.76]						
			FY16	FY17	FY18	FY19	FY20	FY16	FY17	FY18	FY19	FY20	FY21	FY22
NTTPS-IV	Coal	28.1.2010	62%	80%	50%	80%	50%	1255	1616	1010	1616	1010	1616	1616
Rayalaseema-I	Coal	U1- 31.3.1994 U2-25.2.1995	63%	55%	50%	50%	50%	1071	933	848	848	848	848	1357
Rayalaseema-II	Coal	U1- 12.8.2007 U2-29.3.2008	69%	80%	50%	50%	80%	1177	1357	848	848	1357	848	1357
Rayalaseema-III	Coal	10.2.2011	66%	80%	50%	50%	50%	557	679	424	424	424	424	679
Rayalaseema-IV	Coal	01-Oct-17	0%	0%	50%	50%	50%	0	0	2628	2628	2628	2628	3416
Sanjeevaiah I	Coal	01-Mar-14	40%	40%	80%	80%	80%	2798	2798	5606	5606	5606	5606	5606
Sanjeevaiah II	Coal	01-Dec-14	26%	26%	80%	80%	80%	1807	1807	5606	5606	5606	5606	5606

5.3.3 Using the backing down helper

In case sale of surplus is not possible, the user needs to back down capacity in order to manage surplus by adjusting PLFs. This helper sheet aids the user in following the merit order to back down capacity. That is, backing down is done such that the station with the highest variable cost is backed down first. The total power demand as determined from the inputs in the sales sheets is taken and the user can input the amount of surplus energy that would be sold year-wise. Thus the targeted power purchase is the sum of the power demand and the targeted surplus. The user can enter the minimum PLF (default: 50%) at which thermal power stations should run. Based on these inputs and the merit order stack provided in the backing down helper, the PLFs can be adjusted. This is illustrated in Screenshot 6.

Screenshot 6: Using the backdown helper

	J	K	L	M	P	Q	R	S
1								
2								
3	FY 18				FY 19			
4	Power Demand (MUs)			55942	Power Demand (MUs)			61514
5	Targetted Surplus (MUs)			1000	Targetted Surplus (MUs)			1000
6	Target Power Purchase (MUs)			56942	Target Power Purchase (MUs)			62514
7	Remaining Surplus (MUs)			8761	Remaining Surplus (MUs)			3829
8	Min PLF			50%	Min PLF			50%
9	Surplus	Station/Unit	MUs backed down	Modified PLF	Surplus	Station/Unit	MUs backed down	Modified PLF
10	8761	Ramagundam-B	0	0%	3829	Ramagundam-B	0	0%
11	8761	Rayalaseema-IV	1577	50%	3829	Rayalaseema-IV	1577	50%
12	7185	Rayalaseema-II	509	50%	2252	Rayalaseema-II	509	50%
13	6676	Rayalaseema-I	509	50%	1743	Rayalaseema-I	509	50%
14	6167	Rayalaseema-III	254	50%	1234	Rayalaseema-III	254	50%
15	5912	Kothagudem-A	0	0%	980	Kothagudem-A	0	0%
16	5912	Kothagudem-B	0	0%	980	Kothagudem-B	0	0%
17	5912	Kothagudem-C	0	0%	980	Kothagudem-C	0	0%
18	5912	NTPC Simhadri Stage I	1212	50%	980	NTPC Simhadri Stage I	980	56%
19	4701	NTPC Simhadri Stage II	557	50%	0	NTPC Simhadri Stage II	0	80%
20	4143	NTTPS-I	509	50%	0	NTTPS-I	0	80%
21	3634	NTTPS-II	509	50%	0	NTTPS-II	0	80%
22	3125	NTTPS-III	509	50%	0	NTTPS-III	0	80%
23	2616	NTTPS-IV	606	50%	0	NTTPS-IV	0	80%
24	2010	VTPS V (800 MW)	0	0%	0	VTPS V (800 MW)	0	0%
25	2010	NLC TS II Stage-I	141	50%	0	NLC TS II Stage-I	0	80%
26	1870	NLC TS II Stage-II	247	50%	0	NLC TS II Stage-II	0	80%
27	1623	NLC-TNPL Tuticorin	309	50%	0	NLC-TNPL Tuticorin	0	80%

C| PP Summary | H1| Backdown Helper | P0| PP Assumptions | P1| PP All | P2| GenCo The

Row 7 provides the remaining surplus for each year which needs to be reduced to zero by lowering the PLFs of various high cost stations. Given a minimum PLF of 50% (row 8), Rows 10 to 29 list the target PLFs (columns M and S) for various stations in the order of decreasing variable costs. Columns L and R indicate the additional energy that will be backed down by modifying PLFs to the target PLFs. The user needs to manually change the PLFs of the stations in the power purchase sheets. The user may choose to back down a given station by adopting any other strategy and need not be restricted to the merit order. This is shown in Screenshot 6 where stations located in Telangana are entirely backed down (hence “Modified PLF” is 0%) before other stations are backed down.

5.3.4 Availability-based fixed costs and PLF-based incentives

For all thermal power plants, normative and actual availability can be input by the user. Together, these inputs are used to determine the “availability adjusted fixed cost” payments. Note that, by default, normative availability is taken from the “P0| PP assumptions” sheet. This can be overridden in the individual power purchase sheets as shown in Screenshot 7. If availability is below norm, availability adjusted in the ratio of the actual availability to the norm. Screenshot 8 illustrates how this is done.

Screenshot 7: Defining normative availability

	A	B	C	M	N	O	P	Q	R	S	T
1	Unit	Fuel	Date of Commercial Operation (COD)	Normative Availability - NAPAF (%)	Availability (%)						
2					FY14	FY15	FY16	FY17	FY18	FY19	FY20
3	NTTPS-I	Coal	U1-1/11/1979 U2-10/10/1980	80%	81%	95%	76%	70%	85%	85%	85%
4	NTTPS-II	Coal	U3-5/10/1989 U4-23/08/1990	80%	81%	95%	76%	70%	85%	85%	85%
5	NTTPS-III	Coal	U5-31/03/1994 U6-24/02/1995	80%	81%	94%	76%	70%	85%	85%	85%
6	NTTPS-IV	Coal	28.1.2010	80%	90%	101%	68%	78%	87%	87%	87%

P0| PP Assumptions / P1| PP All / P2| GenCo Thermal / P3| GenCo Hydro / P4| Central / P5|

Screenshot 8: Calculation of availability adjusted fixed costs

	A	B	C	BX	BY	BZ	CA	CB	CC	CD	CE	CF
1	Unit	Fuel	Date of Commercial Operation (COD)	Availability-adjusted Fixed Cost (Rs. Cr) For availability below norm, [Adj. Fixed Cost = Fixed Cost * Availability/Norm]								
2				FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22
3	NTTPS-I	Coal	U1-1/11/1979 U2-10/10/1980	61	74	63	88	104	106	108	110	112
4	NTTPS-II	Coal	U3-5/10/1989 U4-23/08/1990	61	74	63	88	104	106	108	110	112
5	NTTPS-III	Coal	U5-31/03/1994 U6-24/02/1995	61	74	63	88	104	106	108	110	112
6	NTTPS-IV	Coal	28.1.2010	192	221	186	213	211	221	232	244	256

P0| PP Assumptions / P1| PP All / P2| GenCo Thermal / P3| GenCo Hydro / P4| Central / P5|

Similarly, PLF incentive is determined based on the normative PLF. If PLF is above the norm, an incentive is calculated as per the compensation awarded by the respective regulator. The normative PLF and the incentive can be input in the “P0| PP Assumptions” sheet. Normative PLF can be overridden for each plant in the individual power procurement sheets.

5.3.5 How to input solar and wind capacity addition

The existing renewable energy (RE) capacity is assigned average tariffs as per historical trends. For each future year, levelised tariff can be input for solar and wind capacity coming online in that year. This is illustrated in Screenshot 9. The tariffs for future years can be entered in column AN. These tariffs are applicable for the year in which the capacity is added and escalated as per the rates provided in column AO. If levelised tariffs are input in column AN, the escalation rate would be set to 0%.

Screenshot 9: Providing levelised tariffs for new renewable energy capacity

	A	B	AJ	AK	AL	AM	AN	AO
1	Non-Conventional Energy Sources	Technology	Levelized Tariff (Rs/kWh)					
2			FY14	FY15	FY16	FY17	2018 or Install	Escalation (%)
3	Bio-Mass	Biomass	17.84	14.48	6.71	5.79	5.79	0%
4	Bagasse	Biomass	3.96	7.88	4.55	4.19	4.19	0%
5	Industrial Waste based power project	Biomass	17.14	5.85	5.89	5.71	5.71	0%
6	Mini Hydel	SHP	10.70	4.10	2.81	2.36	2.36	0%
7	NCL Energy Ltd (TB Dam)	SHP	1.80	1.69	1.69	1.81	1.81	0%
8	Chettipeta Mini Hydel Station	SHP	6.08	0.04	3.74	3.72	3.72	0%
9	Wind Total	Wind						0%
10	Solar Total	Solar						
11	Wind Power- Existing	Wind	3.58	5.33	4.36	4.51	4.51	0%
12	Wind 2018	Wind					4.20	0%
13	Wind 2019	Wind					4.00	0%
14	Wind 2020	Wind					3.80	0%
15	Wind 2021	Wind					3.60	0%
16	Wind 2022	Wind					3.50	0%
17		Wind						
18	Solar Power - Existing	Solar	24.39	6.07	7.48	6.12	6.12	0%
19	JNNSM Bundled Power Solar Phase I	Solar				10.64	10.64	0%
20	JNNSM Bundled Power Solar Phase II	Solar					5.36	0%
21	Solar 2018	Solar					4.00	0%
22	Solar 2019	Solar					3.75	0%
23	Solar 2020	Solar					3.50	0%
24	Solar 2021	Solar					3.25	0%
25	Solar 2022	Solar					3.00	0%
26		Solar						
27	Total							

P3| GenCo Hydro / P4| Central / P5| Private / H2| RPO / P6| NCE / S1| SP Sales and

5.3.6 How to use the RPO Helper

In order to project future capacity addition, the user can also use the RPO helper. Sheet "H2| RPO" helps in determining yearly solar and non-solar capacity addition requirement in sheet "P6| NCE". This is calculated based on the Renewable Purchase Obligation (RPO) of each DISCOM. RPO is determined on the basis of sales for each DISCOM. RPO backlog for each DISCOM from previous years that needs to be fulfilled with future RE purchases can also be input. There is also provision to add capacity based on policy mandates (see Screenshot 10).

Screenshot 10: Using the RE capacity addition/RPO helper

	B	C	D	E	F	G	H
27							
28	**Solar**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
29	Solar RPO requirement (MU)	129	1770	2577	3544	4688	6062
30	Solar PLF %	17%	19%	21%	22%	23%	23%
31	Existing Capacity (FY 17)	**858**	858	858	858	858	858
32	JNNSM Phase I	**39**	39	39	39	39	39
33	JNNSM Phase II		850	850	850	850	850
34	Capacity addition 2018		**0**	0	0	0	0
35	Capacity addition 2019			**0**	0	0	0
36	Capacity addition 2020				**396**	396	396
37	Capacity addition 2021					**567**	567
38	Capacity addition 2022						**682**
39	**Solar Capacity required to meet RPO (MW)**	**897**	**1747**	**1747**	**2143**	**2710**	**3392**
40	**Solar Capacity addition (MW)**		**850**	**0**	**396**	**567**	**682**
41	**Solar MUs**	**1374**	**2781**	**2781**	**3544**	**4688**	**6062**
42	**AP State Solar Policy 2015**				**5000**		
43	**Solar Capacity required per MNRE policy (MW)**	**897**	**2684**	**4472**	**6259**	**8047**	**9834**
44	**Solar Capacity addition (MW)**		**1787**	**1787**	**1787**	**1787**	**1787**
45							
46							
47	**Non-Solar**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
48	Non-Solar RPO requirement (MU)	2589	4220	5349	6130	7485	8660
49	Met by non-wind sources (MUs)	508	750	921	1091	1262	1432
50	Wind RPO requirement (MUs)	2081	3470	4428	5039	6223	7228
51	Wind PLF %	16%	24%	25%	26%	27%	28%
52	Existing Capacity (FY 17)	**2266**	2266	2266	2266	2266	2266
53	Capacity addition 2018		**1300**	1300	1300	1300	1300

P5| Private | H2| RPO | P6| NCE | S1| SP Sales and Migration | S2| SP Migration Option Rates | S3| SP

5.4 Estimation of Demand

The demand estimation section provides detailed inputs for sales growth for various categories and sales migration for each of these categories through various options.

5.4.1 Consumer category nomenclature for sales, tariff and revenue estimation

Sales as well as tariffs and revenue are segregated into different consumer categories. For HT categories, consumers are further disaggregated based on voltage levels (EHV, 33 kV or 11kV). LT consumers are further split on the basis of consumption slabs or connected load into 'small', 'medium' or 'large' sub-categories. These sub-categories are mapped to existing consumer categories as illustrated in Table 4.

Table 4: Mapping consumer categories

RATE Model Categorization	Andhra Pradesh Consumer Categories
HT Industrial	HT I (A) except Lights and Fans, HTI(B)
HT Others	Lights and Fans, HT I (C)- HT VIII
LT Domestic Small	LT I (A)
LT Domestic Medium	LT I (B)
LT Domestic Large	LT I (C)
LT Commercial Small	LT II (A)

LT Commercial Large	LT II (B)
LT Industrial	LT-III: Only Industrial Normal
LT Agriculture With DSM	LT V(A)
LT Agriculture Without DSM	LT V(B)
LT Others	LT-II (C&D), LT-III: Normal, LT-IV, LT-V(C), LT-VI, LT-VII, LT-VIII
RESCO 11 kV	RESCO 11 kV

5.4.2 Sales projections

The user has to input an annual percentage growth rate for each category for the upcoming 5 years in the model. The growth rate is applied to the base year sales entered by the user in the model to project sales for each category. As shown in Screenshot 11, the user inputs the sales for a category in column D. Using the growth rate specified in column B, the sales numbers are projected category-wise for each year in the columns E to I.

Screenshot 11: Providing category wise sales numbers and growth rates

	A	B	C	D	E	F	G
1	APSPDCL						
2	Consumer Category & Consumption Slab	Assumed CAGR (%)	Voltage/Slab/ Load-wise Sales (%)	Sales based on growth projections (MU)			
3				FY 17	FY 18	FY 19	FY 20
4	HT Industrial	1%		7108	7179	7251	7323
5	EHV	1%	36%	2568	2593	2619	2645
6	33kv	1%	47%	3336	3369	3403	3437
7	11kv	1%	17%	1204	1216	1229	1241
8	HT Others	18%		2362	2787	3289	3881
9	EHV	18%	40%	937	1105	1304	1539
10	33kv	18%	14%	333	393	464	547
11	11kv	18%	46%	1092	1289	1521	1795
12	HT Total	5%		9470	9966	10540	11204
13	LT Domestic	18%		7652	9030	10655	12573
14	LT Domestic Small	18%	30%	2274	2683	3166	3736
15	LT Domestic Medium	18%	53%	4088	4824	5692	6717
16	LT Domestic Large	18%	17%	1290	1523	1797	2120
17	LT Commercial	9%		1743	1900	2071	2257
18	LT Commercial Small	9%	6%	93	101	110	120
19	LT Commercial Medium	9%	45%	742	809	882	962
20	LT Commercial Large	9%	55%	907	989	1078	1175
21	LT Industrial	11%		892	990	1099	1220
22	LT industrial small	11%	43%	383	426	472	524
23	LT industrial large	11%	57%	508	564	626	695
24	LT Agriculture	15%		8479	9751	11213	12895
25	With DSM	15%	99.96%	8476	9747	11209	12890
26	Without DSM	15%	0.04%	3	4	4	5
27	LT Others	11%		1390	1543	1713	1902
28	Total LT	15%		20156	23214	26751	30847
29	Total (LT+HT)	12%		29626	33180	37291	42051
30	RESCO 11 kV	7%		435	465	498	533

H2| RPO | P6| NCE | S1| SP Sales and Migration | S2| SP Migration Option Rates | S3| SP Revenue

5.4.3 Sales Migration Options and Inputs

Sales migration is calculated in sheets "S1| SP Sales and Migration" for SPDCL and "E1| EP Sales and Migration" for EPDCL. Sales migration options in the model include migration to the following options:

a. **Captive** – this can be from renewable energy or conventional sources. In case it is from renewable energy sources, concessions on sales migration charges may apply. Captive power can also be on-site (and thus there is no wheeling of power or associated charges) or off-site (in which case wheeling charges apply). Thus, captive sales migration can be onsite RE, offsite RE, onsite non-RE and offsite non-RE. Rooftop solar is treated as a special case of captive onsite RE. Consistent with the policy in AP, additional surcharge and cross subsidy surcharge (CSS) are currently not applicable to sales that migrate through the captive route.

b. **Open Access** – All open access consumers pay wheeling charges, CSS and additional surcharges in the model. Consumers who avail power from renewable energy sources can be provided concessional rates. Andhra Pradesh has 100% concessions for wheeling charges for renewable sources and 100% concessions for cross-subsidy surcharges and additional surcharges for power purchased from solar generators located within state geographical boundaries.

The user can choose the proportion of category-wise sales that migrate through the open access and captive routes. This is done in the "sales and migration" sheets and is illustrated in the blue-shaded cells in Screenshot 12. There is a helper sheet named "H3| Open Access Calculator" which can be used to enter the category-wise proportion of sales migration (this is described in section 5.4.5). The quantum of sales migrating from each category is subtracted from the projected sales in the same sheet to arrive at net sales for the category which is then used to calculate revenue from retail tariffs and for determining energy requirement of DISCOMs.

Screenshot 12: Sales migration via renewable energy open access

	A	D	E	F	G	H	I	J	K	L
1	APSPDCL									
32										
33	Sales migration due to	Open Access as a % of total sales				% of total sales to OA RE				
34	Open Access	FY 19	FY 20	FY 21	FY 22	FY 17	FY 18	FY 19	FY 20	FY 21
35	HT Industrial									
36	EHV	2%	3%	3%	3%	0.9%	1.2%	1.5%	1.8%	2.1%
37	33kv	2%	2%	3%	3%	0.6%	0.8%	1.2%	1.5%	1.9%
38	11kv	2%	2%	3%	4%	0.6%	0.9%	1.2%	1.6%	2.0%
39	HT Others									
40	EHV	2%	2%	2%	2%	0.8%	1.0%	1.1%	1.3%	1.4%
41	33kv	1%	1%	1%	1%	0.2%	0.3%	0.4%	0.5%	0.6%
42	11kv	1%	1%	1%	2%	0.4%	0.5%	0.7%	0.8%	1.0%
43	HT Total									
44	LT Domestic									
45	LT Domestic Small	0%	0%	0%	0%					
46	LT Domestic Medium	0%	0%	0%	0%					
47	LT Domestic Large	0%	0%	0%	0%					
48	LT Commercial									
49	LT Commercial Small	0%	0%	0%	0%					
50	LT Commercial Medium	0%	0%	0%	0%					
51	LT Commercial Large	0%	0%	0%	0%					
52	LT Industrial									
53	LT industrial small	0%	0%	0%	0%					
54	LT industrial large	0%	0%	0%	0%					
55	LT Agriculture									
56	With DSM	0%	0%	0%	0%					
57	Without DSM	0%	0%	0%	0%					
58	LT Others	0%	0%	0%	0%					
59	Total LT									
60	Total (LT+HT)									
61	RESCO 11 kV	0%	0%	0%	0%					
62	Total (LT+HT+RESCO)									

P5| Private | H2| RPO | P6| NCE | S1| SP Sales and Migration | S2| SP Migration Option Rates | S3| SP Revenue | S4| SP Distribution Cost

5.4.4 Sales Migration Rates

The rates applicable for sales migration are listed in sheets "E2| EP Migration Option Rates" and "S2| SP Migration Option Rates". Sales migration rates include wheeling charges, cross subsidy surcharge (CSS), standby charges, additional surcharge and penalties for exceeding contracted demand. The wheeling charges and additional surcharge are input by the user on a per unit basis, the CSS is estimated based on the losses, tariffs and costs specified as per the formula in the National Tariff Policy. The standby charge levied and the penalty for exceeding contracted demand is a function of the excess power procured which needs to be input by the user as a proportion of the sales migration assumed by the user.

For example, charges from open access renewable energy (OA RE) consumers of EPDCL which also includes in-state solar generation are estimated as follows:

a. **Wheeling charges**: The wheeling charge input in the "Wheeling Charges (Rs/kWh)" table of the "E2| EP Migration Option Rates" sheet (adjusted for any applicable rebate specified in the same table) is multiplied by the quantum of sales migration calculated in the "Sales to OA RE (MU)" section of "E1| EP Sales and Migration" to calculate the revenue from wheeling charges in the "Wheeling Charges (Rs.Cr)" section of the "E1| EP Sales and Migration" sheet.
b. **Cross Subsidy Surcharge (CSS)**: The CSS input in the "CSS Charges (Rs/kWh)" table of the "E2|EP Migration Option Rates" (adjusted for any applicable rebate specified in the same table) is multiplied with the quantum of sales migration estimated in the "E2| EP Sales and Migration" to arrive at the revenue for the DISCOM from CSS. The rate specified in the "CSS Charges" section is itself decided based on the average power purchase cost and voltage-wise losses and T&D charges in the "Cross subsidy surcharge parameters" table in the "E2| EP Migration Option Rates" sheet, and the proportion of estimated ABR for the category in the "CSS Charges" section (which is set to 20% as recommended in the National Tariff Policy, but can be changed by the user). As rebates to open access charges are only applicable to intra-state solar power, the user needs to enter how much of the RE open access estimated is intra-state and solar in the "Open Access from non-solar" and "Open access type" sections in the "E2| EP Migration Option Rates" sheet.
c. **Additional Surcharge:** The per unit additional surcharge input in the "E2|EP Migration Option Rates" sheet (adjusted for any applicable rebate specified in the same table) is multiplied by the quantum of sales migration estimated in the "E2|EP Sales and Migration" sheet to calculate the total revenue from additional surcharge in the "E2|EP Sales and Migration" sheet. As the applicability for the concession is only for intra-state solar projects, the treatment is the same as CSS.
d. **Standby charges and associated penalties:** The proportion of sales via open access or captive which uses standby power is input in the "Standby Use" section of the "E2|EP

Migration Option Rates" and applicable rate is specified in the "Standby Charge (Rs/kWh)" section of the same sheet. When multiplied with the quantum of sales migration estimated in the "E2|EP Sales and Migration" sheet, revenue from standby charges is determined (in the "E2|EP Sales and Migration" sheet). Likewise, penalties for exceeding the contracted demand are calculated by using the same sales quantum, proportion of excess procurement from demand, the per-unit fixed cost and penalty multiplier in the "Retail supply tariff" section of the "E2| EP Migration Option Rates".

5.4.5 *How to use the Open Access Calculator*

Sheet "H3| Open Access Calculator" is a helper sheet that aids in inputting the percentage values for sales migration to Open Access and Captive options. Refer to Screenshot 13 for more details. The blue cells in this sheet are the input options. The first table in the sheet (Rows 2 to 10) calculates the migration likelihood of an HT consumer.

Screenshot 13: Extent of sales migration through the open access calculator

Migration Likelihood	Non RE Open	RE Open	RE Captive	RE Captive Offsite	Non RE Captive	Non RE Captive Offsite
Assumed Base Rate	4	4	4	4	4	4
Wheeling Charges	0.04	0	0	0	0	0.04
CSS	1.34	0.402	0	0	0	0
Additional Surcharge	1	1	0	0	0	0
Assumed Effective Rate	6.38	5.402	4	4	4	4.04
Assumed HT DISCOM tariff	6.67	6.67	6.67	6.67	6.67	6.67
Savings from migrating	**5%**	**23%**	**67%**	**67%**	**67%**	**65%**

HT Sales migration by 2022	Baseline	Sales migration scenario	Proportions
Overall	**10%**	**50%**	
Open Access	**3%**	**15%**	**30%**
RE	2%	11%	70%
Non RE	1%	5%	30%
Captive	**7%**	**35%**	**70%**
Onsite RE	2%	9%	25%
Offsite RE	2%	9%	25%
Onsite Non RE	2%	9%	25%
Offsite Non RE	2%	9%	25%
	10%	50%	

		Open Access						
Baseline	**FY 17**	**FY 18**	**FY 19**	**FY 20**	**FY 21**	**FY 22**		**Baseline**
HT Industrial							**80%**	**HT Industr**
EHV	1%	2%	2%	3%	3%	3%	60%	
33kv	1%	1%	2%	2%	3%	3%	20%	
11kv	1%	1%	2%	2%	3%	4%	20%	
HT Others							**20%**	**HT Others**
EHV	1%	1%	2%	2%	2%	2%	75%	
33kv	0%	0%	1%	1%	1%	1%	5%	

E4| EP Distribution Cost | E5| EP Energy accounting | E6| EP ARR | **H3| Open Access Calculator**

To understand the functioning of this sheet, let us assume that in the baseline scenario 10% of all HT consumers migrate by FY 22 (C14). E15 to E22 (blue cells) can be filled up by entering percentage values to denote which sales migration option would be selected. If 30% of the migrating sales are through open access, the remaining 70% would migrate through the captive route. Further, the user can allocate a % of open access sales migration to RE sources (cell E15: 70%) and remaining (30%) would migrate to non-RE sources. Similarly, of sales migrating to captive sources can be classified as onsite RE, offsite RE, onsite non-RE, offsite-non RE (cells E19 to E22: 25% each of the 70% that migrate to captive sources). Once this is done, the user needs to allocate the sales migration proportions between HT Industrial category and HT Others (Cell I27 to I24), resulting in the final category-wise migration percentages (to the right of column I). These numbers can be copied over to the "Sales and Migration" sheets directly. The same process can be repeated for captive migration options.

5.5 Energy Accounting

Section 4.2 provides a brief overview of the various calculations in the energy accounting sheet. Some example calculations are explained below:

5.5.1 Estimation of total energy requirement give T&D losses

The voltage wise T&D losses and sales numbers are used to estimate the energy requirement. Based on the power procurement from long term sources, the shortage or surplus is established. The energy accounting table is depicted in Screenshot 14 for SPDCL.

Screenshot 14: Estimation of surplus/shortages

	A	B	C	D	E	F	G
1		APSPDCL					
2		Energy Accounting	FY 17	FY 18	FY 19	FY 20	FY 21
3		Sales at DT level (MU)	20156	23152	26611	30607	35226
4		Losses at DT level	4.75%	4.51%	4.42%	4.33%	4.24%
5		Power available below 11 kV (MU)	21162	24245	27842	31993	36786
6		Sales at 11 Kv (MU)	2682	2890	3129	3404	3719
7		Losses at 11 kV	3.65%	3.47%	3.40%	3.33%	3.27%
8		Power available below 33 kV (MU)	24747	28111	32061	36616	41875
9		Sales at 33 Kv (MU)	3584	3628	3676	3726	3780
10		Losses at 33 kV	3.61%	3.43%	3.36%	3.29%	3.23%
11		Total power at D<->T periphery (MU)	29392	32867	36979	41714	47179
12		EHV sales (MU)	3375	3508	3670	3865	4099
13		Intra-state transmission losses	3.34%	2.90%	2.87%	2.85%	2.83%
14		Total power demand at state G<->T periphery (MU)	33899	37461	41849	46916	52771
15		Inter-state power procurement (MU)	10747	7807	8116	8116	8116
16		Inter-state transmission losses	3.57%	3.57%	3.50%	3.43%	3.36%
17		Intra-state power procurement (MU)	22919	35382	35494	43480	44627
18		Total power procurement at state G<->T periphery (MU)	33282	42911	43326	51317	52470
19		Surplus (+)/Deficit (-) (MU)	-617	5450	1477	4401	-301
20		Power purchase (+) /sale (-) via inter-DISCOM sales	0	0	0	0	301
21		Inter-DISCOM sale settlement (Rs. Crs)	0	0	0	0	123
22		Surplus (+)/Deficit (-) after D-D settlement (MU)	-617	5450	1477	4401	0
23							

S5| SP Energy Accounting / S6| SP ARR / E1| EP Sales and Migration / E2| EP Migration Option Rate / E3| EP Revenue

The losses at the DT level, 11 kV level, 33 kV level and EHV level are specified in Row 4, Row 7 and Row 10 respectively. The voltage wise sales from the Sales and Migration sheet is reported in Row 3, Row6, Row 10 and Row 12. The sales are grossed up using voltage-wise distribution losses and intra-state transmission losses, resulting in the total energy requirement at the state level in Row 14. On the supply side, power generation from in-state and out-of-state sources as reported in "P1 |PP All" sheet is shown in rows 17 and 15 respectively. Inter-state transmission losses are applied as specified in row 16 to arrive at the total power available at the state boundary. The difference between estimates for power requirement in row 14 and total power available in row 18 determines the surplus or shortages.

5.5.2 Surplus/Shortages and their treatment

In case of surplus, the user can back down capacity via PLF adjustments as described in sections 5.3.2 and 5.3.3. Screenshot 15 is another snapshot of the energy accounting sheet in the model.

Screenshot 15: Sale of surplus/purchase to meet shortages

	B	C	D	E	F	G	H
23							
24	**Surplus Management**	**FY 17**	**FY 18**	**FY 19**	**FY 20**	**FY 21**	**FY 22**
25	Surplus (MU)	0	5450	1477	4401	0	0
26	% surplus available for sale	100%	100%	100%	100%	100%	100%
27	Surplus available for sale (MU)	0	5450	1477	4401	0	0
28	Revenue from sale of surplus (Rs. Cr)	0	1395	378	1127	0	0
29	**Source of sale**						
30	*Sale via bilateral markets*	50%	50%	50%	50%	50%	50%
31	*Sale via power exchanges*	30%	30%	30%	30%	30%	30%
32	*UI transactions*	20%	20%	20%	20%	20%	20%
33	**Rate of sale**						
34	*Bilateral*	3.00	3.00	3.00	3.00	3.00	3.00
35	*Power Exchange*	2.70	2.70	2.70	2.70	2.70	2.70
36	*UI*	1.25	1.25	1.25	1.25	1.25	1.25
37							
38	**Deficit Management**	**FY 17**	**FY 18**	**FY 19**	**FY 20**	**FY 21**	**FY 22**
39	Shortage (MU)	617	0	0	0	0	0
40	% of shortage to be addressed	80%	80%	80%	80%	80%	80%
41	Short term power requirement (MU)	494	0	0	0	0	0
42	**Source of purchase**						
43	*Purchase via bilateral markets*	60%	60%	60%	60%	60%	60%
44	*Purchase via power exchanges*	20%	20%	20%	20%	20%	20%
45	*UI transactions*	20%	20%	20%	20%	20%	20%
46	**Rate of sale (Rs.kWh)**						
47	*Bilateral*	3.00	3.00	3.00	3.00	3.00	3.00
48	*Power Exchange*	2.70	2.70	2.70	2.70	2.70	2.70
49	*UI*	1.25	1.25	1.25	1.25	1.25	1.25
50							
51	Load shedding conducted (MU)	123	0	0	0	0	0
52	Cost of short term power purchase (Rs. Cr)	128	0	0	0	0	0
53							

S5| SP Energy Accounting | S6| SP ARR | E1| EP Sales and Migration | E2| EP Migration Option Rate | E3| EP Revenue | E4| EP Dis

The user can specify the proportion of surplus for sale in Row 27. Based on the proportion of surplus sold through trading licensees or to DISCOMs, power exchanges and the power settled via the DSM mechanism input by the users in rows 30, 31 and 32 respectively and the rate of sale of power through each avenue input in rows 34 to 36, the revenue from surplus is determined in row 28.

In case of shortages, the user can chose to procure short term power from trading licensees, DISCOMs or power exchanges, or the power can settled via the DSM mechanism. The proportion of purchase from each avenue and the rate of purchase is estimated in a similar fashion in to sale of surplus. The final cost due to short term power procurement is estimated in row 53. In case the user does not procure short term power, the DISCOM will have to undertake load shedding during the year, whose quantum is reported in row 51.

If one DISCOM faces shortages and the other surplus, the surplus DISCOM first allocates the power to the shortage DISCOM at a rate specified in the "P0| PP Assumptions" sheet (described in Table 3). The cost impact of such inter-DISCOM sale is shown in the energy accounting sheets.

5.5.3 *Estimation of transmission costs*

The energy accounting sheets project the transmission charges based on FY17 transmission charges entered in the "Transmission cost" section. Screenshot 16 illustrates this (rows 94 and 96). Growth rates for transmission charges need to be input in cells I94 and I96. The projected per-unit transmission charges are multiplied with the applicable intra-state and inter-state power procurement to calculate the total transmission costs in rows 95 and 97.

Screenshot 16: Estimation of transmission costs

	B	C	F	G	H	I
79	Non Solar REC requirement (MU)	0	0	0	0	
80	Average rate of non solar REC (Rs/kWh)	2	2	2	2	
81	Total cost of non-solar REC (Rs Cr)	0	0	0	0	
82	Procurement in excess of non-solar RPO (MU)	709	1191	874	864	
83	**Cost incurred in excess of RPO (Rs.Cr)**	**325**	**533**	**388**	**376**	
84						
85	**Power Procurement costs**	**FY 17**	**FY 20**	**FY 21**	**FY 22**	
86	Total power purchase (MUs)	34160	45294	50087	55566	
87	Cost of long term power procurement (Rs. Crs)	12265	17820	19807	22513	
88	Cost of short term power procurement (Rs. Crs)	128	0	0	0	
89	Cost adjustment due to inter-DISCOM exchanges	-179	-471	-740	-988	
90	Cost of REC (Rs. Crs)	0	0	0	0	
91	Total cost of power procurement (Rs. Crs)	12214	17348	19067	21526	
92						
93	**Transmission cost**	**FY 17**	**FY 20**	**FY 21**	**FY 22**	**CAGR (%)**
94	Intra-state transmission charges (Rs/kWh)	0.23	0.34	0.38	0.43	13%
95	Intra-state transmission costs (Rs. Crs)	549	1274	1604	2049	
96	Inter-state transmission charges (Rs/kWh)	0.07	0.08	0.08	0.08	1%
97	Inter-state transmission costs (Rs. Crs)	246	343	384	430	
98	Total transmission costs (Rs. Crs)	795	1617	1987	2479	
99						
100						
101						

S4| SP Distribution Cost | **S5| SP Energy Accounting** | S6| SP ARR | E1| EP Sales and Migration | E2| EP Migration Option

5.5.4 *RPO compliance and its impact*

Based on the estimated energy requirement and the procurement of renewable energy power input in the "P6l PP NCE" sheet, RPO compliance status and impact are analysed in the energy accounting sheets. Screenshot 17 provides details of this analysis.

The solar and non-solar renewable purchase obligation percentage is an input value and the energy quantum calculation is based on the total sales in each DISCOM. As RPO is based on sales, the magnitude required to be purchased by the DISCOM to ensure compliance will reduce with increase in sales migration. In case of shortfall of RPO compliance, there is provision in the model to purchase Renewable Energy Certificates (RECs). The user can input the rate at which RECs (solar and non-solar) are purchased. The table also calculates the cost incurred due to capacity addition in excess of RPO (rows 69 and 83).

Screenshot 17: RPO compliance

	Renewable Energy Purchase Requirement	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22
55	**Total consumption (MU)**	33776	37461	41849	46916	52771	59519
56	Solar RPO (%)	0.25%	3%	4%	5%	6%	7%
57	Solar RPO backlog to be met (MU)	0	39	43	53	8	0
58	Solar RPO requirement (MU)	84	1163	1717	2399	3175	4166
59	Solar RE purchase (MU)	903	1831	1831	2334	3091	4005
60	Cost of solar power (Rs/kWh)	6.32	5.84	5.84	5.34	4.83	4.41
61	Solar RPO excess (+)/shortfall (-) (MU)	819	668	114	-65	-83	-161
62	Inter-DISCOM solar purchase (MU)	0	0	0	65	83	161
63	Cost of Inter-DISCOM solar purchase (Rs. Cr)	0	0	0	35	40	71
64	Solar RE purchase after inter-DISCOM adj (MU)	903	1831	1831	2399	3175	4166
65	Solar REC requirement (MU)	0	0	0	0	0	0
66	Average rate of solar REC (Rs/kWh)	1	1	1	1	1	1
67	Total cost of solar REC (Rs Cr)	0	0	0	0	0	0
68	Procurement in excess of solar RPO (MU)	819	668	114	0	0	0
69	**Cost incurred in excess of RPO (Rs.Cr)**	**517**	**390**	**67**	**0**	**0**	**0**
70	Non-Solar RPO (%)	5%	6%	7%	8%	9%	10%
71	Non-solar RPO backlog to be met (MU)	0	416	492	0	0	0
72	Non-solar RPO requirement (MU)	1689	2663	3421	3753	4749	5952
73	Non- Solar RE purchase (MU)	2398	4316	4428	4540	4931	5717
74	Cost of non-solar power (MU)	4.59	4.44	4.46	4.48	4.45	4.35
75	Non Solar RPO excess (+)/shortfall (-) (MU)	709	1653	1007	787	181	-235
76	Inter-DISCOM non-solar sale (-)/purchase (+) (MU)	-438	-359	-977	-1156	-1814	0
77	Cost of Inter-DISCOMnon- solar sale (-)/ purchase (+) (	-179	-147	-399	-471	-740	0
78	Non Solar RE purchase after inter-DISCOM adj (MU)	1960	3957	3451	3385	3117	5717
79	Non Solar REC requirement (MU)	0	0	0	0	0	235
80	Average rate of non solar REC (Rs/kWh)	2	2	2	2	2	2
81	Total cost of non-solar REC (Rs Cr)	0	0	0	0	0	35
82	Procurement in excess of non-solar RPO (MU)	709	1653	1007	787	181	0
83	**Cost incurred in excess of RPO (Rs.Cr)**	**325**	**733**	**449**	**352**	**81**	**0**

S5| SP Energy Accounting | S6| SP ARR | E1| EP Sales and Migration | E2| EP Migration Option Rate | E3| EP Revenue | E4| EP Dis

If one DISCOM has RE procurement for solar and non-solar in excess of requirement, then the excess RE power can also be allocated to the other DISCOM. This is shown in row 63 for solar and row 76 for non-solar.

5.6 Distribution Cost

Costs related to the distribution segment of the utility business are predominantly wires costs and are discussed in three sections – capital expenditure, operation and maintenance, and other costs. These costs are detailed out in the "E4| EP Distribution Cost" sheet for EPDCL and "S4| SP Distribution Cost" sheet for SPDCL.

5.6.1 Capital Expenditure

As per the APERC regulations, the capital expenses are determined based on the Weighted Average Cost of Capital (WACC) approach. This measure will capture the debt and equity related expenses for the DISCOM. As shown in Screenshot 18, in order to estimate the Return on Capital Employed (RoCE) during the year for the DISCOM, the user has to specify the capitalisation in C5 to H5. The capitalisation can be specified on an annual basis or based on a growth specified in I5. The user would also need to specify the retirement of assets if any. This would help estimate the opening and closing balances for fixed assets during the year in row 4 and row 5. Depreciation costs are calculated (in row 13) based on inputs for rate of depreciation (row 9) multiplied by the capital expenses (row 3) net of capital expenses financed through grants (row 11) and the consumer contribution (row 12).

The user will also need to input the ratio between debt and equity (row 15), the interest on long term loads (row 16) and the % return on equity (row 17) earned by the DISCOMs. These parameters are used to estimate the % WACC (Weighted Average Cost of Capital) in row 18.

Screenshot 18: Estimation of capital expenses

	A	B	C	D	E	F	G	H	I
1		**APEPDCL**							
2		Capital Expenditure	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22	CAGR (%)
3		**Capital expenses (Fixed Assets) (Rs. Cr)**							
4		Opening Balance	5592	6372	7258	8263	9404	10699	
5		Addition in fixed assets (Capitalisation)	780.25	886	1005	1141	1295	1470	14%
6		Retirement	0	0	0	0	0	0	0%
7		Closing balance	6372	7258	8263	9404	10699	12168	
8		**Depreciation (Rs. Cr)**							
9		% Depriciation	6%	6%	6%	6%	6%	6%	
10		Assets depreciated							
11		Capex financed through grants	16	16	16	16	16	16	
12		Consumer Contribution	120	128	137	147	157	168	7%
13		**Depreciation (Rs. Cr)**	**327**	**374**	**426**	**486**	**554**	**631**	
14		**Weighted average cost of capital (WACC)**							
15		Debt- Equity Ratio	3	3	3	3	3	3	
16		Interest on long term loans	12%	12%	12%	12%	12%	12%	
17		Return on equity	14%	14%	14%	14%	14%	14%	
18		WACC	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	
19		**Return on capital employed**							
20		Regulated rate base (Opening Balance)	1948	2198	2486	2818	3200	3638	
21		Addition to regulated rate base	159	184	213	246	284	327	
22		Regulated rate base (Closing Balance)	2198	2486	2818	3200	3638	4142	
23		**ROCE (Rs. Cr)**	**275**	**311**	**352**	**400**	**455**	**518**	
24		**Total Capital Expenditure (Rs. Cr)**	**602**	**684**	**779**	**886**	**1009**	**1149**	
25									

E3| EP Revenue | **E4| EP Distribution Cost** | E5| EP Energy accounting | E6| EP ARR | H3| Open Access (

Based on the opening balance of the rate base (row 20), addition of assets in each year which has not been financed through grants, and depreciation, the addition to the rate based is determined (row 21). WACC rate is applied to the resulting closing balance (row 22) to calculate the RoCE in row 23. The sum of the depreciation costs and the RoCE estimated determines the total capital expenditure.

5.6.2 Operation and Maintenance

The operation and maintenance (O&M) costs are arrived at by entering the rate of growth for employee expenses, administrative and general costs and repair and maintenance costs for each year. The employee expenses and the administrative and general costs are based on the base year expenses and an input growth. Repair and maintenance expenses are fixed at 2% of the fixed assets.

5.6.3 Other costs

RATE-AP also accounts for other distribution costs such as the working capital requirement (estimated as 1/12 of the O&M expenses) as well as income tax payments, appropriation for safety measures, all of which need to be input for the base year and projected based on specified growth rates.

5.7 Revenue and revenue gap estimation

5.7.1 Revenue and Tariff

Category-wise revenue from sale of power and tariffs are calculated in sheets "S3| SP Revenue" and "E3| EP Revenue". The consumer categories are the same as described in Section 5.4.1 and used in the "Sales and Migration" sheets. Screenshot 19 illustrates how revenue is calculated.

Screenshot 19: Category-wise tariff inputs

APEPDCL

	B	I	J	K	L	M	N	O	P	Q
2	Consumer Category & Consumption Slab	% Annual increase in Average Billing Rate					Average Billing Rate (Rs/			
3		FY 18	FY 19	FY 20	FY 21	FY 22	FY 17	FY 18	FY 19	FY 20
4	HT Industrial	3%	3%	3%	3%	3%	6.64	6.87	7.11	7.35
5	EHV	5%	5%	5%	5%	5%	5.87	6.16	6.47	6.79
6	33kv	3%	3%	3%	3%	3%	6.91	7.09	7.28	7.46
7	11kv	2%	2%	2%	2%	2%	7.92	8.07	8.22	8.37
8	HT Others	2%	2%	1%	1%	1%	7.53	7.65	7.76	7.88
9	EHV	2%	2%	2%	2%	2%	6.77	6.91	7.05	7.19
10	33kv	1%	1%	1%	1%	1%	7.35	7.42	7.50	7.57
11	11kv	1%	1%	1%	1%	1%	9.03	9.12	9.21	9.30
12	HT Total	3%	3%	3%	3%	3%	6.86	7.07	7.28	7.49
13	LT Domestic	3%	3%	3%	3%	3%	3.09	3.18	3.27	3.36
14	LT Domestic Small	3%	3%	3%	3%	3%	1.98	2.03	2.10	2.16
15	LT Domestic Medium	3%	3%	3%	3%	3%	3.14	3.23	3.33	3.43
16	LT Domestic Large	3%	3%	3%	3%	3%	5.59	5.76	5.93	6.11
17	LT Commercial	3%	3%	3%	3%	3%	9.24	9.51	9.80	10.09
18	LT Commercial Small	3%	3%	3%	3%	3%	8.54	8.80	9.06	9.33
19	LT Commercial Medium	3%	3%	3%	3%	3%	9.28	9.55	9.84	10.14
20	LT Commercial Large	3%	3%	3%	3%	3%	9.28	9.56	9.85	10.14

APEPDCL

	B	Q	R	S	T	U	V	W	X	Y
2	Consumer Category & Consumption Slab	Rate (Rs/kWh)			% Revenue from Fixed Charges					
3		FY 20	FY 21	FY 22	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22
4	HT Industrial	7.35	7.61	7.87	15%	15%	15%	15%	15%	15%
5	EHV	6.79	7.13	7.49	11%	11%	11%	11%	11%	11%
6	33kv	7.46	7.66	7.85	16%	16%	16%	16%	16%	16%
7	11kv	8.37	8.53	8.69	20%	20%	20%	20%	20%	20%
8	HT Others	7.88	7.99	8.11	11%	11%	11%	11%	11%	11%
9	EHV	7.19	7.33	7.48	4%	4%	4%	4%	4%	4%
10	33kv	7.57	7.65	7.72	13%	13%	13%	13%	13%	13%
11	11kv	9.30	9.40	9.49	20%	20%	20%	20%	20%	20%
12	HT Total	7.49	7.71	7.94	14%	14%	14%	14%	14%	14%
13	LT Domestic	3.36	3.45	3.54	0%	0%	0%	0%	0%	0%
14	LT Domestic Small	2.16	2.22	2.29	0%	0%	0%	0%	0%	0%
15	LT Domestic Medium	3.43	3.53	3.64	0%	0%	0%	0%	0%	0%
16	LT Domestic Large	6.11	6.29	6.48	0%	0%	0%	0%	0%	0%
17	LT Commercial	10.09	10.39	10.70	7%	7%	7%	7%	7%	7%
18	LT Commercial Small	9.33	9.61	9.90	37%	37%	37%	37%	37%	37%
19	LT Commercial Medium	10.14	10.44	10.75	5%	5%	5%	5%	5%	5%
20	LT Commercial Large	10.14	10.44	10.76	5%	5%	5%	5%	5%	5%

The user needs to enter the base year average tariffs for each category (column N) and the yearly percentage annual increase in Average Billing Rate (ABR, columns I to M). These are used to project yearly ABRs for the five years (columns O to S). Based on the ABRs and category wise net sales reported in "Sales and Migration" sheets, the revenue from retail tariffs is estimated. The proportion of revenue to be recovered from fixed charges can be specified by the user (columns U to Y) which can help estimate category wise fixed charges.

Significant revenue also comes from government subsidies, sale of surplus and sales migration charges. As shown in Screenshot 20, the total revenue from tariff and non-tariff sources are aggregated in the revenue sheet. The user can input the value for revenue from subsidy for each financial year (row 35). The table also summarises revenue from sales migration charges estimated in "Sales and Migration" sheets and the revenue from sale of surplus estimated in "Energy Accounting" sheets.

Screenshot 20: Revenue from subsidies

	B	C	D	E	F	G	H
1	**APEPDCL**						
32							
33	**Revenue Sources**	**FY 17**	**FY 18**	**FY 19**	**FY 20**	**FY 21**	**FY 22**
34	Revenue from tariff	7401	8113	8917	9823	10848	12006
35	Revenue from subsidy	1200	1200	1200	1200	1200	1200
36	Rebates and incentives						
37	Non tariff income						
38	Revenue from Sales Migration	17	33	44	56	69	84
39	Income from wheeling	1	2	3	4	5	6
40	Income from CSS	7	11	15	20	26	34
41	Standby charge	8	11	14	16	18	20
42	Additional surcharge	0	8	11	14	17	21
43	Contracted capacity charge	1	2	2	2	3	3
44	Revenue from sale of surplus	0	995	748	1479	1188	359
45	**Total Revenue**	8618	10342	10909	12559	13304	13650
46							

S5| SP Energy Accounting / S6| SP ARR / E1| EP Sales and Migration / E2|

5.7.2 How to use the Cross Subsidy Calculator

As mentioned in Section 4.3, this helper sheet can aid the user in checking the impact of various inputs provided in the revenue sheet on the cross subsidy design. In this sheet, category-wise cross subsidy is calculated as a proportion of that category's ABR to average cost of supply. If this proportion is > 100%, it is a "cross-subsidising" category and if the proportion is < 100%, it is a "cross-subsidised" category. Screenshot 21 illustrates this.

Screenshot 21: Cross subsidy calculator

	33kv	123%	121%	118%	113%	111%	108%
	11kv	141%	137%	133%	127%	124%	120%
HT Others							
	EHV	121%	118%	114%	109%	106%	103%
	33kv	131%	126%	122%	114%	111%	107%
	11kv	161%	155%	149%	141%	136%	131%
HT Total							
LT Domestic							
	LT Domestic Small	35%	35%	34%	33%	32%	32%
	LT Domestic Medium	56%	55%	54%	52%	51%	50%
	LT Domestic Large	100%	98%	96%	92%	91%	89%
LT Commercial							
	LT Commercial Small	152%	150%	147%	141%	139%	137%
	LT Commercial Medium	166%	163%	160%	153%	151%	148%
	LT Commercial Large	166%	163%	160%	153%	151%	148%
LT Industrial							
	LT industrial small	129%	125%	122%	116%	113%	110%
	LT industrial large	129%	125%	122%	116%	113%	110%
LT Agriculture							
	With DSM	0%	0%	0%	0%	0%	0%
	Without DSM	66%	66%	66%	65%	65%	65%
LT Others		84%	81%	78%	73%	71%	68%
Total LT							

5.7.3 *Estimation of revenue gap*

The difference between total expenses and total revenue estimated in RATE-AP can lead to a revenue surplus or a revenue gap. Screenshot 22 shows the estimation of the cumulative revenue gap with carrying cost.

Screenshot 22: Determination of revenue gap

	B	C	D	E	F	G	H
1	प्रयास Prayas (Energy Group) APSPDCL						
2	Consumer Category & Consumption Slab	Revenue (Rs. Cr)					
3		FY 17	FY 18	FY 19	FY 20	FY 21	FY 22
49	HT Industrial	6.85	7.98	3%	8223	92	26
50	HT Others	7.08	7.59	1%	2258	12	3
51	HT Total	6.91	7.89	3%	10481	104	29
52	LT Domestic	3.22	4.46	7%	5901	0	5
53	LT Commercial	9.33	10.81	3%	3043	0	4
54	LT Industrial	7.17	7.91	2%	966	0	2
55	LT Agriculture	0.02	0.03	5%	30	0	0
56	LT Others	4.96	5.21	1%	970	0	0
57	Total LT	2.70	3.71	7%	10911	0	11
58	Total (LT+HT)	4.02	5.01	5%	21392	104	40
59	RESCO	0.32	0.52	10%	36	0	0
60	Total (LT+HT+RESCO)	3.96	4.94	4%	21428	104	40
61							
62	Revenue Gap Recovery	FY 17	FY 18	FY 19	FY 20	FY 21	FY 22
63	Current year revenue gap (Rs. Cr)	1148	1540	1460	2365	2376	2916
64	Existing Regulatory Asset and previous year gaps (Rs. Cr)		1148	2813	4577	7439	10622
65	% carrying cost on amount to be recovered	0.11	0.11	0.11	0.11	0.11	0.11
66	Carrying Cost (Rs. Cr)	0	125	305	497	807	1153
67	Total revenue gap (Rs. Cr)	1148	2813	4577	7439	10622	14691
68	Revenue gap as % of total revenue	8%	17%	25%	36%	46%	56%
69							

P5| Private | H2| RPO | P6| NCE | S1| SP Sales and Migration | S2| SP Migration Option Rates | S3| SP R

The user can adjust tariffs to provide consumers a rebate in tariff in case of surplus. Alternatively, in case of revenue gaps, if not recovered in the year through tariffs or revenue subsides will be carried forward with carrying cost. Row 65 specifies that carrying cost rate for the year to be input by the user. The rate is applied to the accumulated revenue gaps from previous years to estimate the carrying cost (row 66) and the total revenue gap (row 67).

6 Scenario building in RATE

Scenarios can be constructed in RATE-AP for the time-period considered by changing the inputs provided by the user. A copy of the model needs to be made for creating each scenario. Results from these scenarios can then be compared and can be used to answer various 'what-if?' questions about the medium term outlook for the state power sector.

These scenarios are neither predictions nor forecasts. Each of the scenarios involves a plausible and realistic description of the utility business in the medium term based on coherent and internally consistent assumptions. The scenarios are instruments to gain a better understanding of key driving forces and relationships which operate in the power sector and impact the utility business.

PEG has developed various scenarios which were used to understand the following issues better.

1. What is the impact of different strategies of power sharing between the states of Andhra Pradesh and Telangana?
2. What are the cost impacts of adding significant RE capacity? With growing surplus power, especially in the face of RE capacity addition, what would be the impacts of adopting different practices for backing down?
3. Andhra Pradesh is already facing significant sales migration of cross subsidizing consumers to open access and captive options. Going forward, there could also be increase migration of LT consumers to roof top solar. What is the impact on costs, revenue gaps and surplus management due to sales migration? Does the impact on revenue gaps and surplus management increase if this sales migration occurs in conjunction with aggressive capacity addition of renewable energy?
4. If sales migration erodes away potential revenue for the DISCOMs, can changes in tariff design (say, increasing the proportion of revenue recovered from fixed charges) prevent sales migration?
5. What is the impact of concessions provided for RE open access in the state?
6. If costs are to increase with limited increase in revenues, there could be a significant increase revenue gaps. Can this revenue gap be managed by increasing tariffs or increasing subsidy?

This section describes results from RATE-AP based on scenarios build using the model which can answer some of these questions.

6.1 Assumptions broadly common to all scenarios

Before we describe specific scenarios, it is important to document the common assumptions for all scenarios developed by PEG. Table 5 describes the broad power purchase related assumptions along with assumptions on transmission costs, distribution costs, demand estimation and sales migration, and revenue incomes. All these assumptions are user inputs made by PEG.

Table 5: Assumptions unchanged across scenarios

Parameter	Time Period/ Category	Assumption	Comments
Conventional Capacity Addition	**FY 18**	Rayalaseema Thermal Power Project, Stage IV (600 MW)	Thermal capacity addition of APGENCO stations in FY 18 and FY 20. APGENCO Hydro capacity of 960 MW added in 2021-22.
	FY 20	Sri Damodaram Sanjeevaiah Thermal Power Station, Stage III (800 MW) Dr Narla Tata Rao Thermal Power Station, in Vijayawada, Stage V (800 MW)	
	FY 22	Polavaram HEP (960 MW)	
Plant Load Factor (PLF)	**FY 17-FY 22**	80%	PLFs for thermal projects considered at normative values as per regulations. For gas based power plants, PLF considered has been at 0%.
Capacity Charge Escalation Rate	**FY 17-FY 22**	2-5%	The rate of increase in these costs has been assumed based on historical trends.
Energy Charge Escalation Rate	**FY 17-FY 22**	4%	

Parameter	Time Period/ Category	Assumption		Comments
Renewable Energy Tariffs (Rs./kWh)	**Source**	**FY 18**	**FY 22**	The tariff trajectories considered for solar and wind sources is such that by FY 22, prices reduce drastically. This has been assumed based on the present discovered rates through competitive bidding.
	Wind	4.20	3.50	
	Solar	4.00	3.00	
	Biomass	5.15	5.07	

	SHP	2.33	2.33	Price reduction trajectory for biomass sources has been considered to be much less drastic.
Transmission Losses	**FY 17-FY 22**	~3%		Transmission Losses and Cost escalation has been assumed based on historic values.
Transmission Cost Escalation	**FY 17-FY 22**	13%		
Power Purchase Share	**SPDCL**	66%		As per state policy
	EPDCL	34%		
Sales growth projections	**SPDCL**	8.40% p.a		Considered as per Resource Plans.
	EPDCL	8.16% p.a		
Sales migration charges	**CSS**	As per National Tariff Policy		While 100% rebate on sales migration charges has been considered for wheeling, for Cross Subsidy Surcharge and Additional Surcharge 100% rebate for intra-state solar open access.
	Additional Surcharge	Rs.1/kWh from 2018		
	Wheeling	As per FY 17 charges		
% tariff increase	**Overall, FY17-FY22**	1.2% p.a		Considered based on historical growth rates.
Distribution cost escalation rates	**FY 17-FY 22**	14-16%		Capital expenses and O & M expenditure escalation rates based on historical values.
Strategy and Rate for Sale of Surplus	**Power Exchange**	30% sale @ Rs. 2.70/kWh		Based on market trends.
	Bilateral	50% sale @ Rs. 3.00/kWh		
	DSM	20% sale @ Rs. 1.25/kWh		

6.2 Example scenarios under RATE

Using RATE-AP, 'what-if?' scenarios were prepared to assess order of magnitude impacts on the financial and selected performance parameters.

The scenarios are based on possible changes due to increased renewable energy (RE) capacity addition, sales migration of cross subsiding consumers due to open access, captive options, and rooftop solar. As per the State Re-organization Act, capacities of the State Generating Companies of Andhra Pradesh and Telangana are being shared. It also explores the possibility that there is no power sharing and that only the State Generation capacity within a state's geographical boundary is utilized by the states.

In order to assess the impacts of various changes, PEG has also developed a **'Baseline'** scenario. The baseline scenario is an approximation of the utility business in the medium term based on historical trends, current performance, regulatory norms and highly likely changes. It has been used as a reference from which an alternative outcome can be measured, e.g. the impact of significant RE capacity addition is compared with the baseline scenario, in which RE capacity addition is based on RPOs and assessment of future sales. The scenario with significant RE capacity addition is termed **'High RE'**. Similarly the one with substantial reduction in sales due to open access, captive, and rooftop solar migration is called **'Sales Migration'** and where power sharing does not take place between states is called **'No sharing'**. The major assumptions in these scenarios are shown in Table 6. As is evident from the table PEG has also build two scenarios where the combined effect of two or three changes are assessed. A brief description of the scenarios and the impact and feasibility of actions/strategies to address adverse impacts of scenarios is discussed in this section 6.3.

Table 6: Description of scenarios

Assumptions by FY 22	Baseline Scenario	High RE Scenario	Sales Migration Scenario	No sharing Scenario	Sales Migration + High RE Scenario	Sales Migration + High RE + No Sharing Scenario
RE Capacity	4,687 MW	15,053 MW	Same as Baseline Scenario	Same as Baseline Scenario	Same as High RE Scenario	Same as High RE Scenario
Sales Migration	HT sales: 9-10% RTPV: 1.3-1.6%	Same as Baseline Scenario	HT sales: 46-50% RTPV : 6.3-8.8%	Same as Baseline Scenario	Same as Sales Migration Scenario	Same as Sales Migration Scenario
Sharing of Power	AP: 46% TS: 54%	Same as Baseline Scenario	Same as Baseline Scenario	AP: 100% TS: 0%	Same as Baseline Scenario	Same as No Sharing Scenario

Renewable capacity addition by FY 22, percentage of sales migration, and allocation of state generation capacity are the parameters considered and are varied across the scenarios.

In the **Baseline** scenario, by FY 22, 4,687 MW of renewable capacity gets added. Of the erstwhile state thermal generating capacity of Andhra Pradesh, 46.11% of generating capacity is allocated to the new state of Andhra Pradesh, while the rest is allocated to Telangana. 10% of HT sales and 1.3% of LT sales is assumed to have migrated in the Baseline scenario to Open Access or captive consumption options.

In the **High RE** scenario varies from Baseline only on account of the renewable capacity addition considered. RE Capacity Addition assumed is about thrice as much as Baseline by FY 22 of which solar capacity addition is assumed to be about 2500 MW, wind capacity addition is about 1900 MW.

More sales migration due to Open Access and captive consumption is undertaken in the **Sales Migration** scenario as compared to the Baseline scenario- 50% migration for HT sales and 8.8% sales migrate to rooftop PV solar options.

In the **No Sharing** scenario, it is assumed that generation capacity is not shared according to the Andhra Pradesh Reorganization Act, 2014, but Andhra Pradesh DISCOMs contract full capacity from thermal generating stations that are geographically situated in the state, belonging to APGENCO. It is further assumed that no generation sharing of TSGENCO plants take place.

The effects of higher Sales Migration combined with High RE capacity addition are also observed in the **Sales Migration + High RE Scenario**. Additionally, PEG also has a **Sales Migration + High RE Scenario+ No Sharing** scenario.

6.3 Key observations and results from example scenarios

The impact on power procurement cost and quantum of surplus is assessed for each scenario. As power procurement costs are sensitive to input assumptions, especially the escalation rates and capacity addition assumed, the sensitivity of power procurement to various input parameters was also assessed.

With significant surplus being a likely possibility with High RE capacity addition, PEG also used RATE-AP to assess cost impacts of various 'backing down' strategies.

With growth in costs and only marginal increase in tariffs, the revenue gaps across scenarios will also growth. PEG used RATE-AP to understand the extent of the revenue gap across scenarios and also analysed the impact of various strategies available to the sector actors to eliminate revenue gaps – notably, increase tariffs or increasing subsidy.

As loss of revenue due to significant sales migration is becoming a new reality across states, Andhra Pradesh power sector actors can also assess impact of changes in tariff design to prevent loss of sales or loss of revenue due to open access. In this context PEG has assessed the impact of changing the tariff design to reduce variable cost to prevent sales migration. Notably, it has assessed the potential impact of increasing the fixed cost while keeping average tariffs the same. Levy of additional surcharge to discourage open access and the provision of concessions on wheeling, CSS to encourage RE-based open access have also been tweaked to assess impacts.

6.3.1 Impact on Power procurement quantum and cost in all scenarios

Power procurement quantum increases by 65% in the Baseline scenario from FY 18 to FY 22. As seen in Figure 2, the power procurement quantum falls in the sales migration scenario as net rate of growth of sales in this scenario is lesser than Baseline, with more sales migration. The power purchase mix varies in the High RE scenario as compared to Baseline with more share of generation from renewable sources. The costs impacts on power procurement are summarised in Table 7.

Figure 2: Power Procurement across scenarios

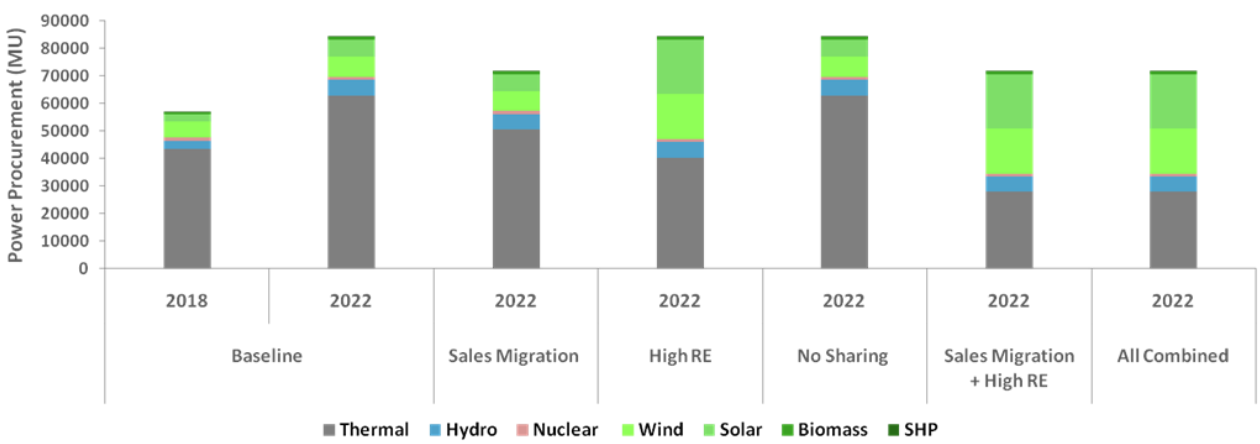


Table 7: Power procurement cost impact

Particulars	Year	Baseline	Sales Migration	High RE	No sharing	Sales Migration + High RE	All Combined
% RE Generation	**FY 22**	17%	21%	44%	17%	52%	52%
Surplus (MU)	**FY 22**	8,800	21,300	31,600	12,000	45,200	48,400
APPC (Rs./unit)	**FY 18**	3.69	3.74	3.78	3.80	3.85	3.89
	FY 22	4.10	4.25	4.23	4.14	4.52	4.55
Total power procurement cost across scenarios (Rs	**FY 18**	21,000	-1.9%	2.2%	2.8%	0.9%	2.0%
	FY 22	34,700	-11.6%	3.2%	1.0%	-6.0%	-5.3%

Cr.)*	
*Order of magnitude analysis- all numbers rounded off to nearest hundred. All % to one decimal point	

There is a significant increase in costs over 5 years in the Baseline itself with a 13% increase in the Average Power Purchase Cost (APPC) and 84% increase in total costs. In the Sales Migration scenario, in spite of backing down, total power purchase cost falls by 12% due to savings in variable cost. However, APPC goes up by 4% over and above the Baseline growth of 13%. In High RE, as compared to the baseline, cost is higher by 3% with 10,366 MW additional RE capacity addition by FY 22. There is an additional ~320 Cr cost increase occurs in fixed costs in the No Sharing scenario. In the Combination Scenarios, there is 10%-11% increase in APPC due to cumulative effects. Overall, the deviation in cost is higher in the scenarios with capacity addition but there is a slight reduction in cost when there is backing down due to savings in variable costs.

6.3.2 Sensitivity of power procurement costs to changes in input variables

With the high growth in costs in the baseline itself, the sensitivity of costs to changes in input parameters was done to assess the sensitivity of the power procurement costs to input assumptions. Table 8 summarises the results and shows that the sensitivity to cost assumptions is not significant. An overall cumulative cost impact of 7% was observed in Baseline, while a change of 8.45% was seen in the High RE scenario.

Table 8: Sensitivity Analysis for power procurement cost

Parameter	Values	Changed Range	Effect on Power Purchase Cost across scenarios in FY22
Fixed Cost	Escalation: 5% 2% for depreciated units	-2% to +2%, +1% to -1% (depreciated units)	-2% to 2.1%
Variable Cost	Escalation: 4%	-2% to 1%	-3.7% to 1.9%
Solar Tariff	Rs. 3 in FY 22	-1 to +1 Re/unit in FY 22	-0.8% to 0.8% in Baseline -2.5% to 2.5% in High RE
Wind Tariff	Rs. 3.5 in FY 22	-1 to +0.7 Re/unit in FY 22	-0.4% to 0.3% in Baseline -1.7% to 1.5% in High RE
Cumulative Cost Impact			-6.9% to 5.1% in Baseline -8.4% to 7.2% in High RE

6.3.3 *Backing down across scenarios*

Surplus power that is backed down in Baseline ranges from 16,600 MU to 8,200 MU from FY 18 to FY 22. The reduction is due to an increase in demand in the baseline. The backing down increases with the fall in demand in the Sales Migration scenario and further increases with increase in capacity in the High RE scenario. Thus the combined scenarios have significant surplus. This extent and impact of surplus is summarised in Table 9.

Table 9: Backing down across scenarios

Year	Scenarios	'Surplus' Power Backed down (MU)
FY 18	Baseline	16,600
FY 22		8,200
FY 22	Sales Migration	20,600
	High RE	30,900
	No sharing	11,400
	Sales Migration + High RE	44,400
	All Combined	47,700

6.3.4 *Impact of surplus management strategies with High RE capacity*

With High RE capacity addition, there the quantum of surplus is more than 30,000 MUs. Thus in this scenario, with backing down of capacity, the average PLF is 45%. Due to variability of reliability of RE sources, scheduling on the basis of the Merit Order may not be able to address balancing and seasonal issues. Thus, impacts of two different fleet management strategies were assessed using the model. These are:

Strategy 1: Shut down high cost plants

High cost plants were shut down all year, in cases of significant all year surplus, instead of partially backing down plants. It was observed that Rs 500 to Rs 600 Cr savings were made as compared to the default strategy of following the Merit order Despatch.

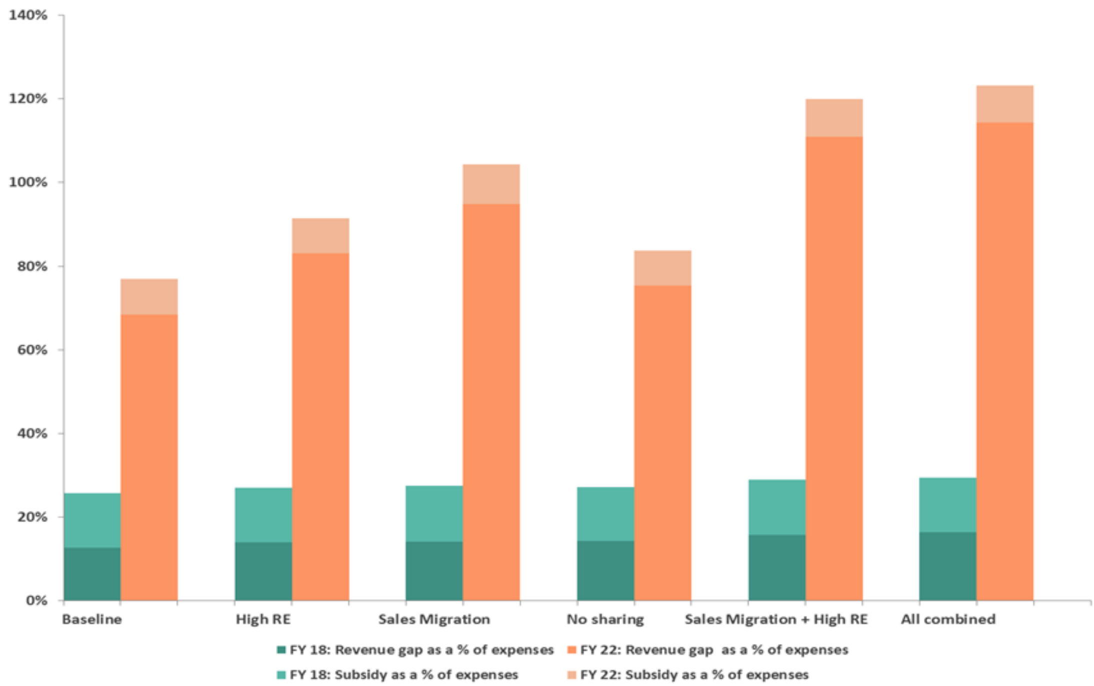
Strategy 2: To facilitate RE integration, thermal generators run at >50% PLF

In order to manage variable and intermittent renewable energy sources, thermal capacity might be required at 50% PLF or more. In order to meet this need, the surplus power generated can be sold in the market at a price less than the variable cost of the thermal power plants in question. Such a strategy as per RATE-AP will incur ~Rs 2600 Cr additional variable cost was incurred as opposed to shutting down high cost units in the High RE scenario. Thus, managing variable renewable energy has significant cost implications.

6.3.5 *Revenue gap across scenarios*

For Baseline, over 5 years, revenue gap after subsidy increases from Rs. 3,800 cr. to Rs. 32,000 cr. This accounts for about 13%-68% of total expenses. Revenue gap across scenarios has been captured in Figure 3.

Figure 3: Revenue Gap across scenarios



Due to significant increase in costs in scenarios such as No Sharing and High RE, revenue gap is higher in these scenarios. Revenue gap in Sales Migration scenario is higher because of fall in revenue. This is shown in Table 10.

Table 10: Comparison of revenue gap across scenarios

% Excess revenue gap over Baseline Scenario	Sales Migration	High RE	No sharing	Sales Migration + High RE	All Combined
FY 18	10%	12%	15%	25%	31%
FY 22	25%	25%	11%	53%	59%

With the significant revenue gap, across scenarios, the revenue gap can be met by increasing tariffs or increasing subsidies. The impacts of these two strategies are described in Section 6.3.6 and Section 6.3.7.

6.3.6 *Revenue gap management strategy: Increase tariff to eliminate revenue gap*

Without meeting revenue gap, the average tariff increase over five years in Baseline is 7.5% (HT: 14%, LT: 17%). Average tariff is about 1% (FY18) to 8% (FY 22) lower in Sales Migration scenario due to reduction in sales.

As shown in Table 11, Sales migration and combination scenarios require the highest tariff increase to meet revenue gap. On an average such a tariff increase translates to 4-7% tariff increase per annum. However, skipping tariff increase for 1 year would more than double tariff increase required next year with accumulating carrying costs. Based on this tariff increase, the average HT tariff across scenarios is at Rs. 13.26/kWh for SPDCL and Rs. 10.59/kWh for EPDCL. This is about double of the cost of using an oversized standalone PV system with battery backup which costs about Rs. 6/kwh for day-time supply.

Table 11: Tariff increase to eliminate revenue gap

Tariff increase required to eliminate revenue gap over five years	Scenarios
23% to 24%	Baseline, No Sharing
26% to 31%	High RE, Sales Migration
37% to 38%	Sales Migration + High RE, All combined

6.3.7 *Revenue gap management strategy: Increase subsidy to eliminate revenue gap*

To bridge the Revenue Gap, the revenue subsidies need to increase by Rs. 8,600 Cr. to Rs. 13,100 Cr per year by 2022 (see Table 12). This amount is over and above the Rs. 4000 Cr. If only 65% of the subsidy payments are met annually, this would result in a revenue gap of Rs. 11,200 - Rs.17, 800 crores by FY 22 as this includes Rs 8,000 crore to Rs. 13,000 crores of accumulated carrying cost.

Table 12: Subsidy needed to meet revenue gaps

FY 22	Unit	Baseline	Sales Migration	High RE	No sharing	Sales Migration +High RE	All combined
Revenue Gap	Rs. Cr.	32,100	40,100	40,000	35,600	49,200	50,900
Additional Subsidy	Rs. Cr	8,600	10,900	9,800	8,900	12,900	13,100

Order of magnitude analysis- All numbers rounded off to nearest hundred. Rates specified up to two decimal points.

6.3.8 Tariff design to manage sales migration

It is observed that the scenarios with higher sales migration have higher revenue gaps. To meet revenue gaps, ERCs could tweak tariff design to deter sales migration and compensate DISCOM for lost revenue by the following strategies:

Increase proportion of revenue from fixed charges to reduce energy charges

Keeping the average tariffs constant, the revenue recovered via fixed charges were increased by 100%. The impact of this increase has been summarised in Table 13. It can be seen even after doubling the revenue from fixed charges, the variable cost reduction is only about 4%-18%. This is not enough to prevent sales migration, as it is still higher than indicative rooftop solar prices at Rs.5/unit. However, the annual fixed cost payments for 1MW+ consumers increase of Rs.60 lakhs/year/MW to Rs.1.25 crores/year/MW due to the doubling of fixed costs. This is comparable to 13% to 28% of capital costs needed for a 1 MW solar PV system. Thus, the strategy can be counterproductive as the increased in fixed cost might incentivize migration to captive options.

Table 13: Impact of doubling fixed charges to prevent sales migration

Category	Average per unit fixed cost in 2022 (Rs./kWh)		Average per unit variable cost in 2022 (Rs./kWh)		% decrease in variable cost	
	APEPDCL	APSPDCL	APEPDCL	APSPDCL	APEPDCL	APSPDCL
HT Industrial	2.08	2.40	5.16	5.50	17%	18%
LT Commercial	1.16	0.92	9.56	9.89	5%	4%
LT Domestic	0.46	0.53	3.08	3.93	13%	12%
LT Industrial	1.54	1.45	6.42	6.47	11%	10%
Overall	1.09	0.77	4.21	3.38	13%	13%

Levy of additional surcharge, concessions for renewable energy based open access:

Concessions for RE open access result in a loss of revenue for the DISCOM since the concessions are not financed via subsidy support from the state. However, the levy of additional surcharge generates revenue for the DISCOM due to recovery of a surcharge from all consumers. The impact of loss of revenue due to removal of additional surcharges is compared with the gain in revenue due to removal of RE-related open access concessions in Table 14.

Table 14: Impact of additional surcharge and RE related concessions

Percentage change in revenue due to :	EPDCL	SPDCL

	FY 18	FY 20	FY 22	FY 18	FY 20	FY 22
Removal of additional surcharge	-23%	-24%	-26%	-22%	-23%	-23%
Removal of all RE open access concessions	23%	27%	32%	19%	24%	29%

It is observed that removal of additional surcharge results in a loss in revenue from sales migration of about 22-26% as compared to the sales migration scenario in each year. Removal of RE rebates results in additional revenue from sales migration of about 29-32% as compared to the sales migration scenario in each year. Therefore, removal of RE concessions results in a 2-6% increase in revenue as compared to a levy of additional surcharge on all consumers. Thus, removal of concessions for some consumers generates more revenue than the levy of a surcharge of Re. 1/unit for all open access consumers.

6.4 Conclusions

From the scenarios, it is clear that AP DISCOMs may face severe financial crisis in the near future even in the business as usual Baseline scenario. The financial crisis will worsen with sales migration and increased RE capacity addition. As compared to the impact of these changes, the impact of not sharing power with Telangana is not major. Increasing tariffs alone to meet the revenue gap or subsidy alone to meet revenue gap is not sustainable. There is a need for transition support, along with efforts by the utilities to reduce the average cost of supply. With low transmission and distribution losses and relatively low distribution costs, major benefit from cost reduction will come reduction in power procurement costs. Therefore there is a need to rationalise future capacity addition and increase efficiency of existing projects.

Sales migration seems to be an inevitable reality and even tweaks in tariff design will not be able to address it significantly. With the migration of cross subsidizing consumers, more attention is needed to provide affordable, quality power to small consumers.

7 Way forward

RATE-AP is designed to be a sense-making tool to assess order of magnitude impacts, especially cumulative impacts of various changes to the electricity utility business. It is hoped that various actors involved in the power sector decision making process find RATE-AP useful for sense-making and understanding emerging trends better.

There are some limitations in the current model, most of which are due to data constraints. With increased data availability and wider consultation, future enhancements to the model are possible. Notably, it would be feasible and highly beneficial to:

> **Add fuel related parameters for cost determination:** Instead of estimating variable costs for thermal plants, especially coal powered plants based on escalation rates,

providing disaggregated inputs for coal quality, coal availability, cost components and station performance can provide useful insights. This is especially relevant as coal costs account for more than half of the power procurement costs for coal based station. With disaggregated fuel data, the impacts of various scenarios such as reduced fuel availability, rationalizing coal transportation costs, increasing the GST compensation cess on coal, improvements in station heat rates, improvements in coal quality and importing coal can be analysed.

Impact of performance improvements: Generation performance parameters such as station heat rate, auxiliary consumption and secondary fuel consumption can have a significant on the ARR, and hence are monitored closely by regulators. However, these have not been modelled in RATE-AP due to lack of data. Similar to fuel inputs, these can be added to the model once data becomes available.

Provision of disaggregated distribution cost inputs: APERC is one of the few SERCs which does a disaggregated bottom-up estimate for operation and maintenance costs based on the assets of the utility. Norms in the recent wheeling tariff order were fixed on a per transformer, per feeder basis, rather than for the combined operations and maintenance head. With the availability of latest estimates, this detail can be added to RATE-AP. Similarly, disaggregated capital expenditure costs especially for new investments can be added to the model to assess efficacy and impacts.

Category-wise subsidy inputs: As of now, the treatment of subsidies is at a DISCOM level. With more clarity on category wise subsidies and its impact on the tariffs in the concerned category, RATE-AP can be modified to provide more detailed subsidy related scenarios.

Increase user-friendliness: As of now RATE- AP with its multiple input options is a flexible and dynamic model but it could be made more user-friendly with better helper functions, more examples and more detailed description of features. With time, a web-based platform can be used to build discourse and facilitate informed discussions on sector issues.

The model is a framework for analysis of cumulative impacts and took significant effort to develop. However, input assumptions and model functionality need to be updated periodically to keep the model relevant going forward.