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THE IMPACT OF COVID-19 ON THE POWER SECTOR IN KARNATAKA, INDIA

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This brief analyzes the impact of COVID-19 on the power sector in the State of Karnataka, India. We explore demand scenarios across a range of severities of the COVID shock as well as other exogenous factors—namely, agricultural demand, hydro generation, and power market prices—and assess their impacts on discom revenue and profits. We find a substantial revenue decrease in energy sold of up to INR 3,600 Crore in 2020 (8% reduction), and a more modest effect of INR 1,420 Crore in 2021. Discom costs vary less, as both fixed costs and non-power-purchase costs do not respond to demand shocks. Losses (negative profits) increase significantly, from INR 4,780-5,700 Crore without COVID-19 to 6,429-8,080 Crore in 2020, and from INR 4,080-4,800 Crore to 4,230-6,780 Crore in 2021. We note that increasing agricultural subsidies and/or residential tariffs by about 20% can offset COVID-19 losses in their entirety.

EXECUTIVE SUMMARY

The COVID-19 pandemic has caused a major decline in electricity demand in India. Given the already distressed finances of many of the country's distribution companies (discoms) and the high proportion of inflexible fixed-cost contracts, this reduction in revenue represents an acute threat to the stability of the distribution utilities. In this brief, we analyze the short-term impact of this demand shock in the state of Karnataka. We explore demand scenarios across a range of severities of the COVID shock as well as other exogenous factors—namely, agricultural demand, hydro generation, and power market prices—and assess their impacts on discom revenue and profits.

We analyze the COVID-19 shock in Karnataka using a power sector dispatch model with generator-level cost data that resolves hourly generation profiles. Using recent data on electricity demand by consumer category, we develop a range of plausible hourly demand scenarios for calendar years 2020 and 2021, and combine with relevant tariff information to determine a full picture of costs and revenues for the state's five discoms.

Based on these demand scenarios, we observe a substantial impact of COVID-19 on discoms' cost recovery in terms of revenues from energy sold to consumers in 2020 and a more marginal effect in 2021. The baseline revenues for 2020 and 2021 range from INR 46,329-47,395 Crore and 46,029-51,604, respectively. In 2020, the most conservative revenue estimate falls below INR 43,000 Crore. In 2021, revenue estimates under COVID-19 range from INR 42,688 -51,418 Crore.

The costs of energy purchased by discoms vary less, as only the variable cost component is affected by the COVID-19 demand shock. The lowest COVID-19 total generation cost in any scenario is INR 49,899 Crore in 2020 and INR 49,468 Crore in 2021, whereas the baseline costs without COVID-19 in low-cost scenarios are INR 51,107 and 50,831 Crore, respectively. One reason for these relatively modest impacts is that fixed costs to generators account for almost a third of the overall power purchase costs to discoms, and they do not change when actual consumption of energy changes.

The profit effect in 2020 is severe, as losses increase from INR 4,778-5,702 Crore to INR 6,429-8,080 Crore, depending on the scenario. In 2021, the decrease is only from INR 4,082-4801 to 4,232-6,780 Crore. A break-up by the various discoms indicate that much of the losses affect BESCOM due to their high share of commercial and industrial consumers.

We also analyze the impacts of different policy options to provide relief. We consider an increase of agricultural subsidies from INR 5.7 to 6.9 / kWh and increased residential tariffs from INR 7.3 to 9 / kWh[1]. We also consider renegotiating power purchase agreements to reverse recent increases in fixed costs. Notably, each policy option all but eradicates the COVID-19 induced losses for both 2020 and 2021. Finally, we also conduct a sensitivity analysis to identify how each consumer group's tariff would impact each discom's revenues differently.

[1] In our model, these tariffs represent "Effective Revenue per Unit", which we compute as the ratio of revenue to units consumed for each consumer category.

INTRODUCTION

The Indian power sector was hit hard by the COVID-19 pandemic. India's distribution companies (discoms) were already struggling with poor financial performance before the pandemic, and COVID-19 has further suppressed demand for electricity. In this situation, discoms face serious financial difficulties and may require additional support.

In this report, we analyze the effect of COVID-19 on electricity demand in the State of Karnataka, which is among India's economic engines and also has substantial renewable energy capacity, which complicates projections of utility finances. We develop electricity demand profiles across a range of severities of the shock as well as other exogenous factors—namely, agricultural demand, hydro generation, and power market prices. Using recent data on electricity demand by consumer category, we develop a range of plausible hourly demand scenarios for calendar years 2020 and 2021. We also use data on power generation capacity, costs, and tariffs.

With the help of a power sector dispatch model and our own simulation, we evaluate the impact of COVID-19 on discom finances in 2020 and 2021. We examine how the COVID-19 shock will shape discom revenue from energy sold, total generation cost, and profits. We also assess possible policy solutions to provide discoms with some relief: increased agricultural subsidies, higher residential tariffs, and renegotiation of power purchase agreements for lower fixed costs.

The report is organized as follows. Section 2 provides a broad overview of the Karnataka power sector. Section 3 summarizes our data and methods. Section 4 presents the results. Section 5 concludes. A separate appendix includes additional detail on our approach; a spreadsheet summarizes all scenario results.

KARNATAKA POWER SECTOR

Karnataka's GDP has consistently ranked amongst the top 5 of all Indian states. In the financial year 2019 (beginning April 1), Karnataka's net state domestic product was INR 210,887 Crore, fourth among the states and 67% higher than the Indian average [1]. Between 2013-2017, Karnataka's economy grew by 8.1% per annum [2].

Karnataka's power generation capacity has high shares from thermal (31%, largely coal), solar (25%), wind (16%), and hydro (16%) [3]. Hydroelectric capacity is mostly owned by the state, whereas thermal power is split between state generation and central inter-state generating stations (ISGS). Solar and wind capacity is entirely owned by independent power producers (IPPs). **Figure 2.1** illustrates the breakdown by generation capacity type.

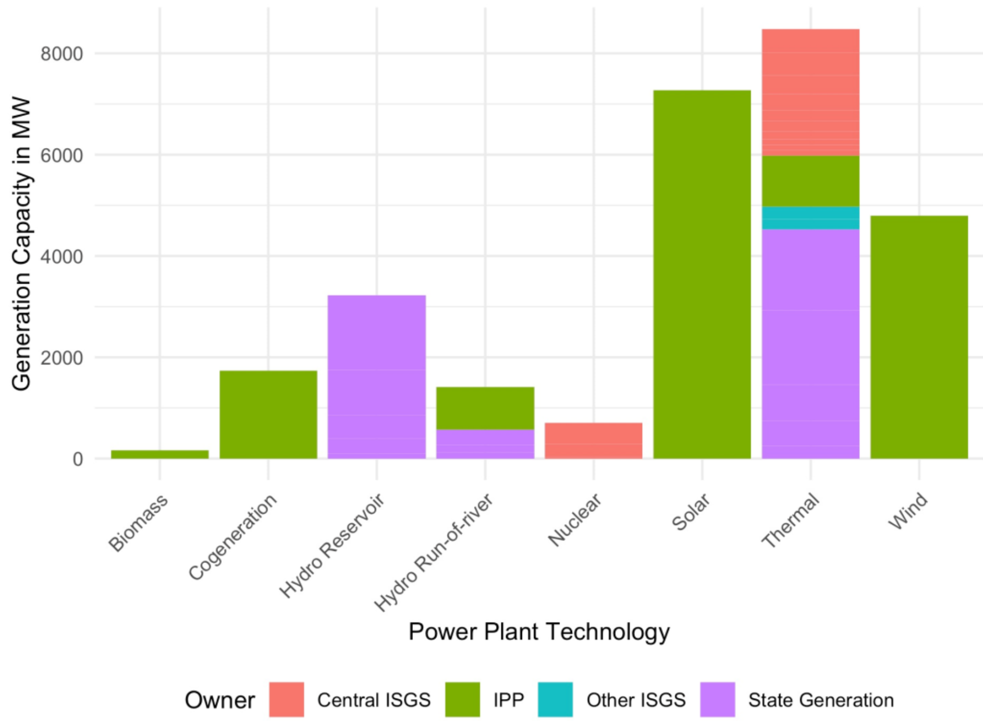

Figure 2.1. Karnataka's power generation capacity by fuel and owner. Source: [3].

Electricity demand in Karnataka comes from agriculture (38%), residential (22%), industry (19%), and commercial and public sector consumption (21%). These patterns are highlighted in **Figure 2.2**.

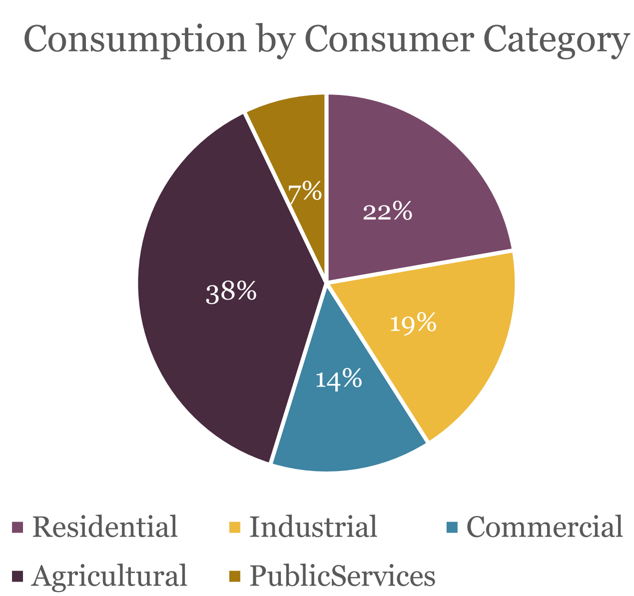

Figure 2.2 Electricity consumption by category. Source: [4].

Similar to many other Indian states, Karnataka's power generation is tethered to expensive long-term power purchase agreements [5]. While intended to encourage generation investments, these agreements include fixed costs (capacity payments) that prevent discoms from taking advantage of variations in short- and long-run power prices and cause discoms to bear disproportionate risk in the case of demand shortfalls. Between financial year 2020 to 2021 alone, annual fixed costs increased from INR 7293 crores to INR 10,727 crores, primarily driven by new contracts with the Karnataka state-owned Bellary and Yermarus thermal power stations.

Karnataka has struggled with relatively slow growth in electricity demand, as shown in **Table 2.1**. Even prior to COVID-19, industrial electricity consumption has contracted in the past five years, while growth has been relatively robust in the residential and public sectors. Overall, the compound annual growth rate for electricity consumption has been only 3.5% between financial years 2014-2018.

	OVERALL CAGR (FY14-18)	Standard Dev. of YoY Growth Rates
Residential	6.01	1.43
Commercial	3.69	4.74
Agricultural	4.15	8.39
Industrial	-1.64	3.39
Public Services	7.45	4.89
TOTAL	3.55	2.68

Table 2.1 Compound annual growth rate of electricity consumption by sector, financial years 2014-2018. Source: [4].

Cross-subsidization of electricity tariffs among consumer classes is substantial in Karnataka. For example, revenue per unit from commercial consumers (11.1 INR/kWh) is almost twice as high as agricultural revenue with subsidy (5.7 INR/kWh). Similarly, revenue per unit from industrial users (9.2 INR/kWh) is much higher than agricultural revenue. Below, **Figure 3.4** shows revenue by consumer category. Karnataka's cross-subsidization underscores the importance of commercial and industrial consumers, as reduced sales to them undermine the profitability of discoms. As a result, Karnataka discom cost recovery is likely to suffer acutely until commercial and industrial sectors rebound.

Given the COVID-related reduction in commercial and industrial demand, combined with expensive long-term contracts, Karnataka's discoms' cost recovery is likely to suffer. Commercial and industrial sectors are more profitable than residential and agricultural electricity, and Karnataka's power purchase agreements carry high fixed costs [3]. Between financial year 2020 to 2021 alone, annual fixed costs increased from INR 7293 crores to INR 10,727 crores, primarily driven by new contracts with Bellary and Yermarus thermal power stations.

We simulate the extent to which Karnataka's discoms might suffer financial losses, under different COVID related demand reduction, and simulate the impact of strategies to mitigate such losses.

DATA AND METHODS

3.1 Data

3.1.1 Demand Estimation and COVID-19 Induced Demand Scenarios

Demand estimations are developed in three steps. First, demand growth rates are disaggregated into five consumer categories: agricultural, residential, industrial, commercial, and public services, according to pre-COVID trends. Demand parameters draw upon data from KERC annual report 2018-2019 and discom filings [4]. **Figure 3.1** illustrates historical patterns of demand in Karnataka.

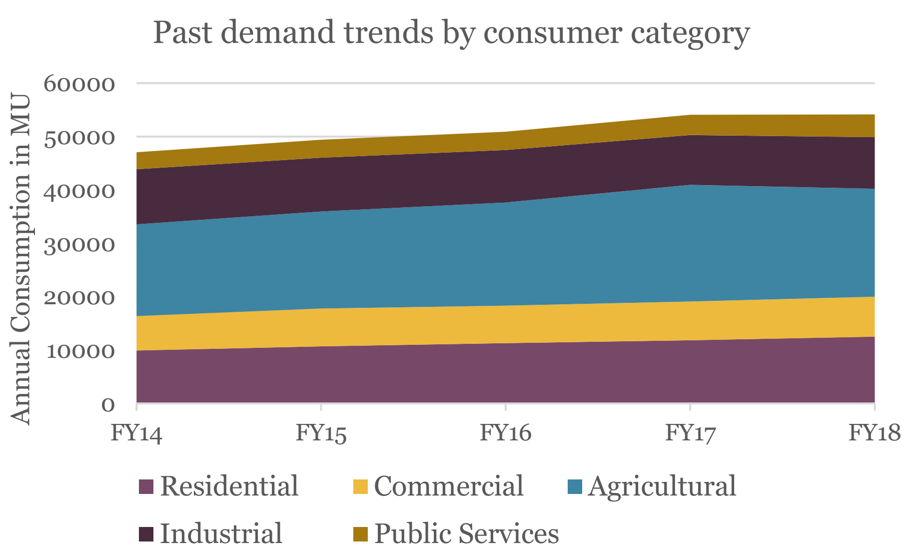

Figure 3.1 Past demand trends by consumer category in Karnataka. Source: [4].

Second, scenarios for COVID-induced demand impacts are estimated for each consumer category, as explained further below. COVID-19 has caused and is expected to continue causing massive declines in commercial and industrial demand, but the extent and magnitude of the demand decline remains unclear. We simulate three scenarios to indicate conservative (slow rebound, low demand growth), moderate, and optimistic (rapid rebound, high demand growth; rapid visions of demand growth, expressed as a percentage reduction in annual growth relative to a no-COVID baseline. We also assume a slight increase in residential load, as we expect that people would from home for longer hours, with increased use of fans and air-conditioners, particularly during the summer months.

Agricultural demand is the largest component of aggregate demand in Karnataka (38%). It is both volatile, depending on rainfall, and insensitive to COVID-19 based on the first months of 2020. It is also heavily subsidized: without subsidies, Karnataka's discoms would lose 5.69 per kWh sold to agricultural consumers, according to our estimates.

Third, hourly demand profiles over the year are constructed from the average of 2017 and 2018 historical profiles (to capture seasonal and diurnal variability), and then scale those to 2019, 2020, and 2021 using historical and projected annual growth rates [3].

The resulting scenarios for year-on-year change in demand growth between Q1/2020 and Q4/2021 for residential, industrial, and commercial users are illustrated in **Figure 3.2**. Agricultural demand is not expected to be sensitive to the COVID-19 demand shock.

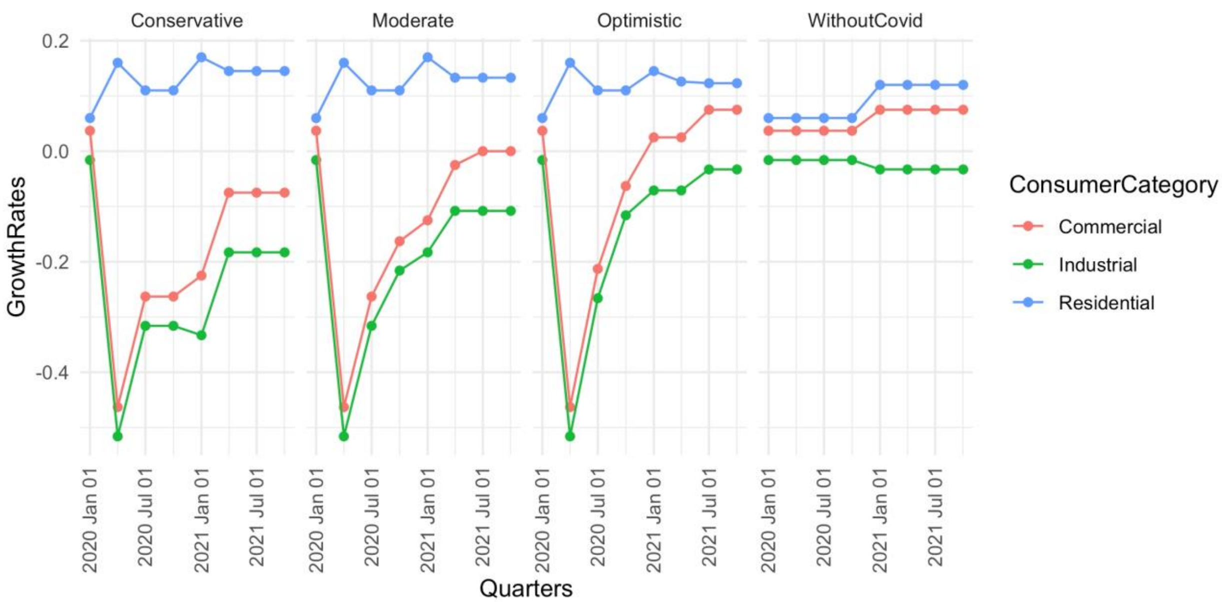

Figure 3.2 COVID-induced variation in electricity demand growth. Source: authors' calculations.

3.1.2 Generation Portfolio and Costs

The generation portfolio for Karnataka was drawn from Merit India [6] and checked against proposed tariff filings for FY 19 by Karnataka's distribution companies [7]. The generation capacity assumed in the model, is presented in **Appendix Figure A1**. The variable costs by plant name and technology are presented in **Figure 3.3**. For all solar plants, we assume a variable cost of INR 4.35 per KWh, as per data on MeritIndia.in website [6]. Where there were discrepancies regarding variable costs between the two sets of data, data from BESCOM's 2020 tariff filings were used [7]. For 2021, we assume that solar capacity increases by 1000 MW. Although Government of Karnataka has allotted and additional capacity of 2400 MW of solar PV [11], we assume an increase in capacity of only 1000MW in 2021, because of lower than expected demand growth.

In addition to the power plants, a small share of energy (approximately 2.5%) is bought through short term trade. We represent short term trade through a dummy plant of capacity 250 MW. As for the prices of short-term trade, we constructed an hourly trend for 2020 by averaging across hourly IEX exchange prices across 3 years from 2017 to 2019 for Karnataka's bidding zone; each hourly data point is the average of three data points. This data was sourced from the IEX website [10]. The assumed hourly power exchange prices are presented in Supporting Data accompanying this report. Finally, although surplus power in Karnataka is sold on the exchange, we do not represent any such export or revenues from such export in our model, as the quantity of power sold is marginal. While we do not have data on power sales on the exchange, we note that only 2% of discom revenue comes from sources outside Karnataka consumers.

Fixed costs to generators, at INR 10727 crores for FY 2021, account for almost a third of the overall power purchase costs to discoms. Fixed costs for each thermal plant have been presented in **Appendix Figure A2**; thermal plants account for 90% of fixed cost charges in FY 2021.

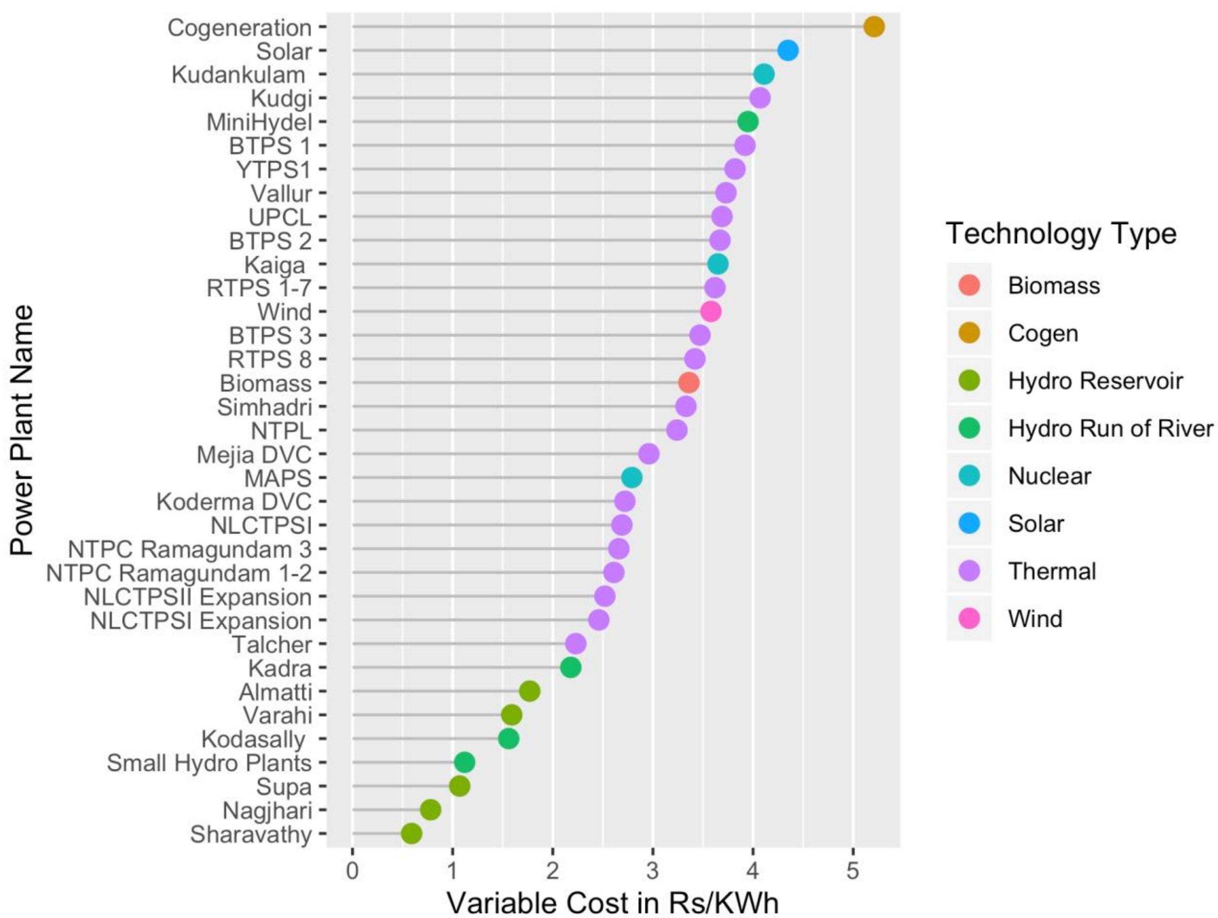

Figure 3.3 Variable costs by generator.

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3.1.3 Cost Recovery Data: Revenues, Subsidies, Consumption

We collected consumption and revenues by consumer category across all five discoms for the years FY 2017-2021. While the data for FY 2017-2019 represent actual costs, FY 2020 and 2021 represent approved and proposed tariffs respectively[2]. We aggregate voltage levels and consumer types into five main categories: Residential, Agricultural, Industrial, Commercial, and Public Services. These are shown in Appendix Tables A1-A2. Finally, a part of the Residential (Bhagya Jyoti and Kutir Jyoti Schemes) and Agricultural (irrigation pump sets less than 10 HP) consumption is mostly subsidized by the Karnataka state government. These subsidized categories are represented separately as "Residential-Subsidized" and "Agricultural-Subsidized".

Figure 3.4 presents the *Effective Revenue Per Unit* from these various consumer categories, for each discom; this metric is computed as the ratio of total revenue to total consumption from a certain consumer category. This metric allows us to accurately represent cost recovery at an aggregate level of consumer category, without going into detailed sub-categories of tariffs set by the regulator.

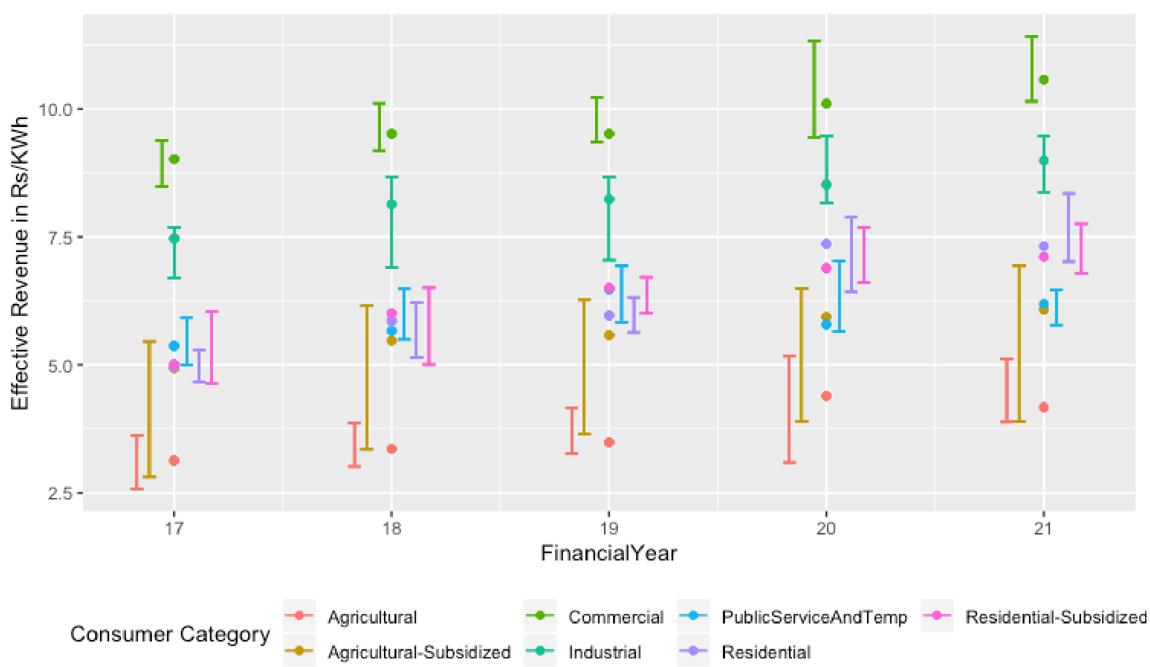

Figure 3.4 Effective revenues per consumer category. The upper and lower points of the error bars represent maximum and minimum effective revenue per unit across all five discoms, while the points represent the median value. Source: various tariff filings.

[2] Our data sources primarily were "form D2" annexures in annual tariff filings by the five discoms.

In **Figure 3.5**, we show electricity consumption by category for the different Karnataka discoms. Notably, BESCOM is responsible for about one-half of all demand in the state.

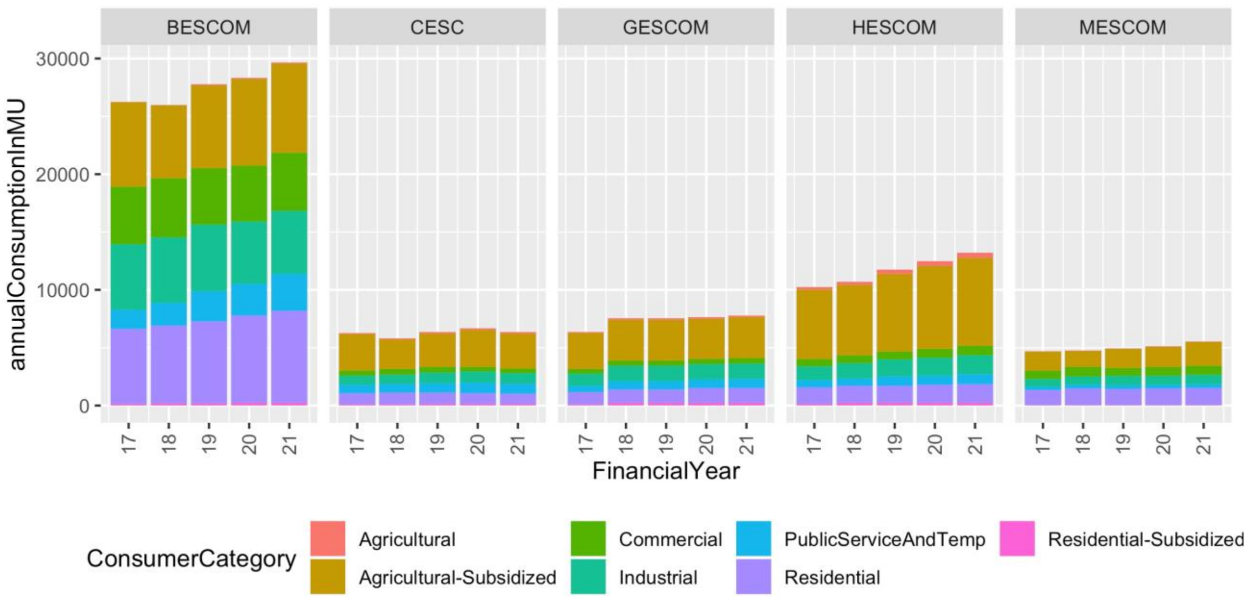

Figure 3.5 Annual energy sold by discom and consumer category. Source: various tariff filings.

Finally, **Figure 3.6** shows energy generated and consumed at different points along the electricity value chain. For each group of bars, the first represents load as reported by SLDC. These values include the load bought by the five main discoms and any other private or public entity. The second bar (yellow) indicates the generation purchased by discoms as measured at the point of generation. Finally, the third bar (dark green) indicates the energy sold by the discom, as reported in their tariff filings. Data for FY18 and FY19 represent actual data, while data for FY 20 and 21 are values projected by individual discoms.

The difference between energy purchased and energy sold constitutes the "Aggregate Technical and Commercial" (ATC) losses; comprising losses both at the transmission level and the distribution level. Losses at the distribution level include commercial losses due to theft, billing and collection inefficiencies etc. The ATC losses, computed as a share of Energy Purchased at generation point, for the years FY 18-21 were found to have a mean value of 15.22% with a range of 14.0-15.9%. For this project we conservatively assume that the ATC losses for the calendar years 2020 and 2021 are 15.9%[3].

In order to calculate revenues, we scale the 'energy purchased' down by 15.9% to incorporate ATC prior to determining discom revenues. We then calculate revenues corresponding to the different

[3] Data for aggregate technical and commercial losses is only publicly available at the level of the discom, and not specified at the level of the consumer category.

shares of demand and effective revenues per unit of the various consumer categories. Model-based generation occurs under the assumption of 3.5% transmission losses. The generation purchased by discoms is scaled down by 3% from the model's generation, to account for a small share of generation bought by other entities through open access[4]. The cost of power purchase to discom is calculated based on the generation purchased by discoms.

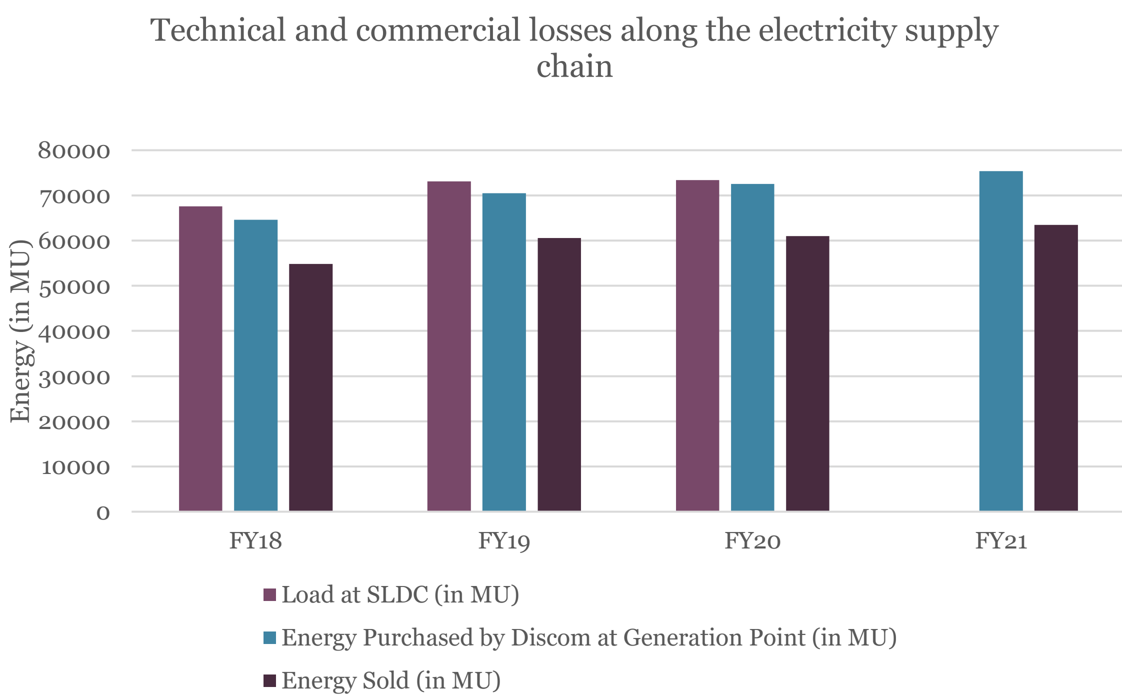

Figure 3.6 Source: [3] and various tariff filings.

3.2 Simulation and Model Description

Figure 3.7 illustrates our modeling approach. On the left, we list the model inputs. At the top, we show the logic of scenario building, distinguishing between COVID-induced demand reductions and exogenous factors that introduce variability. The key outputs include discom generation costs, revenue, and profits.

[4] The figure of 3% was estimated by calculating the difference between energy generated according to the SLDC, and energy purchased by discoms at point of generation.

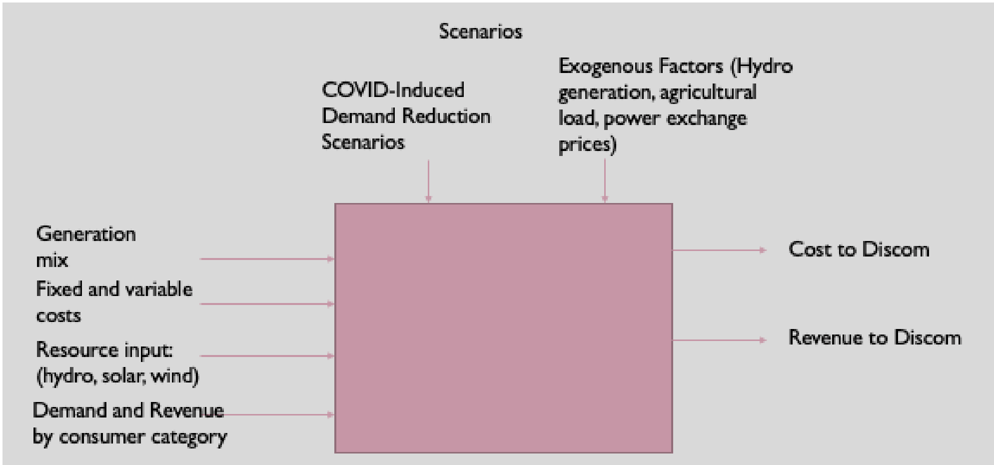

Figure 3.7 The modeling framework: inputs, scenarios, and outputs.

Our model is comprised of two modules: one, an optimization model called Calliope to determine variable cost based dispatch, and second, our own algorithm to translate dispatch into costs and revenues for the discoms.

Calliope [8] is an open source energy systems modelling framework. Calliope was designed to analyze systems with high spatial and temporal resolution, therefore particularly suited to studying systems with high shares of renewables. Although calliope can be used to simulate least cost investment decisions, in this report we use calliope primarily to simulate dispatch under various scenarios of cost, demand, and supply. The scenarios are described in greater detail in the following section.

For this project, Calliope was populated to run at an hourly timescale. We provide hourly demand profiles, and hourly solar and wind profiles for Karnataka, with data available in the 'SupportingData.xlsx' file. Generation is specified at the power station level, based on the parameters mentioned in the preceding section. Our dispatch algorithm assumes that solar PV and wind generation are run in compliance with must-run status; the variable costs are only calculated after dispatch has occurred in the model. Furthermore, without availability data at the plant level, we assume that all plants are available at their full or allocated capacity.

The second module, which translates dispatch outputs from calliope into revenues and costs to discoms, has been built in-house using the R statistical programming language.

3.3 Scenario analysis

3.3.1 Experiment design

The three core scenarios with a COVID-19 demand shock are labeled conservative (slow rebound, low demand growth), moderate, and optimistic (rapid rebound, high demand growth). The primary difference between the three scenarios is the degree to which COVID-19 influences industrial and commercial electricity demand, as illustrated in **Figure 3.2** above. Note that we also assume a slight increase in residential demand in the future, notably in the summer months.

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In the **conservative** scenario, demand rebounds only slowly. The initial 50% demand decrease in commercial and industrial consumption continues to linger, with demand remaining 30% below pre-COVID levels until the first quarter of 2021 and then recovering to 15% below until end of 2021. This scenario can be thought of as a prolonged public health crisis and a slow economic recovery.

In the **moderate** scenario, the initial 50% demand decrease in commerce and industry is reduced to 20% below pre-COVID levels by end of 2020. At the end of 2021, demand in these sectors is only 7.5% below pre-COVID levels.

In the **optimistic** scenario, we assume a rapid rebound. At the end of 2020, industry and commerce are only 10% below pre-COVID demand levels, and their demand fully recovers by third quarter of 2021.

Finally, all of these scenarios are compared with a baseline scenario, **Without COVID,** which assumes that demands continue to grow at pre-COVID trends.

For each of the scenarios, we consider three different combinations of exogenous demand drivers unrelated to COVID-19. In Karnataka, key exogenous drivers include (i) inexpensive hydroelectric output and (ii) agricultural demand for irrigation, both of which depend heavily on rainfall. We also consider power market prices.

These combinations can be summarized as follows:

- In the high hydro / low agricultural demand case, we assume:
    - Excellent hydroelectric production due to abundant rainfall. Specifically, we assume 13,891 GWh of hydroelectricity (highest annual total in the past decade).
    - Low agricultural demand. Specifically, we assume that agricultural demand drops by 7.28% in 2020 and by 15.09% in 2021 (7.28% applied cumulatively) compared to 2019 values. These percentages correspond to the lowest CAGR for agricultural demand between FY14-18.
    - Low power market prices. Specifically, we assume an average hourly exchange price pattern of 2017-2019 less one standard deviation.

- In the medium hydro / agricultural demand case, we assume:
    - Typical hydroelectric production. Specifically, we assume 11,231 GWh of hydroelectricity (medial annual total in the past decade).
    - Low agricultural demand. Specifically, we assume of agricultural demand that agricultural demand grows at 4.15 % in 2020 and by 8.47% in 2021 compared to 2019 values. The value 4.15% corresponds to the average CAGR for agriculture from FY 14-18.
    - Intermediate power market prices. Specifically, we assume an average hourly exchange price pattern of 2017-2019.

- In the low hydro / high agricultural demand case, we assume:

- Weak hydroelectric production. Specifically, we assume 6,091 GWh of hydroelectricity (lowest annual total in the past decade).
- Low agricultural demand. Specifically, we assume that agricultural demand increases by 12.6% in 2020 and by 26.8% in 2021 (12.6% applied cumulatively) compared to 2019 values. The value 12.6% corresponds to the highest year-on-year growth between FY14-18.
- High power market prices. Specifically, we assume an exchange price pattern of 2017-2019 plus one standard deviation.

Data for hydroelectric production came from CEA's annual generation reports 2008-2019 [9] and agricultural demand growth comes from KERC's Annual report [4]. As for power exchange prices, we constructed an hourly trend for 2020 by averaging across hourly IEX exchange prices across 3 years from 2017 to 2019 for Karnataka's bidding zone; each hourly data point is the average of three data points. This data was sourced from the IEX website [10].

These 12 combinations are summarized in the **Table 3.1** below and details are available in **Appendix Figures B1-B2**.

Scenario Si. No.	*COVID-induced scenarios*	*Exogenous factors driven by rainfall and agricultural load.*
1	Conservative	High hydro and low agri load
2	Conservative	Median hydro and median agri load
3	Conservative	Low hydro and high agri load
4	Moderate	High hydro and low agri load
5	Moderate	Median hydro and median agri load
6	Moderate	Low hydro and high agri load
7	Optimistic	High hydro and low agri load
8	Optimistic	Median hydro and median agri load
9	Optimistic	Low hydro and high agri load
10	Baseline Without COVID	High hydro and low agri load
11	Baseline Without COVID	Median hydro and median agri load
12	Baseline Without COVID	Low hydro and high agri load

Table 3.1 Experimental design.

3.3.2 Simulation of Alternative Policy Options

As possible mitigation measures, we consider three policy options. The first, **additional agricultural subsidies,** increases agricultural subsidies from INR 5.7 to 6.9 / kWh, so as to reduce discom losses from serving agricultural consumers. This increase of 1.2 INR / kWh, it turns out, is approximately enough to offset the COVID-19 impact on discom finances.

Second, in **higher residential tariffs**, we consider the possibility of increasing residential tariffs from INR 7.3 to 9 / kWh. We assume that residential electricity consumption is inelastic to this price change, so this analysis can be considered the best possible scenario. This increase brings residential tariffs approximately in line with industrial tariffs.

Third, we consider **renegotiated power purchase agreements** to reverse the significant increase in fixed costs between financial years 2020 and 2021. As noted above, fixed costs have increased significantly over the past two years, and we explore the financial impact of reducing them back to pre-pandemic levels.

RESULTS

4.1 Demand Scenarios and Generation for 2020 and 2021

Figure 4.1 shows the demand scenarios for the calendar years 2020 and 2021. The above panel shows the demand projections for 2020, with the first four months based on historical data and the rest based on modeling results. The below panel shows the outcomes for the calendar year 2021. The dashed line is the baseline scenario without COVID-19. The left panel illustrates the conservative COVID-19 scenario, the middle panel the moderate scenario, and the right panel the optimistic scenario. The three solid lines are the three exogenous combinations of hydro output, agricultural demand, and power market prices under different COVID-19 scenarios. Annual loads by scenario are shown in **Appendix Table D1**.

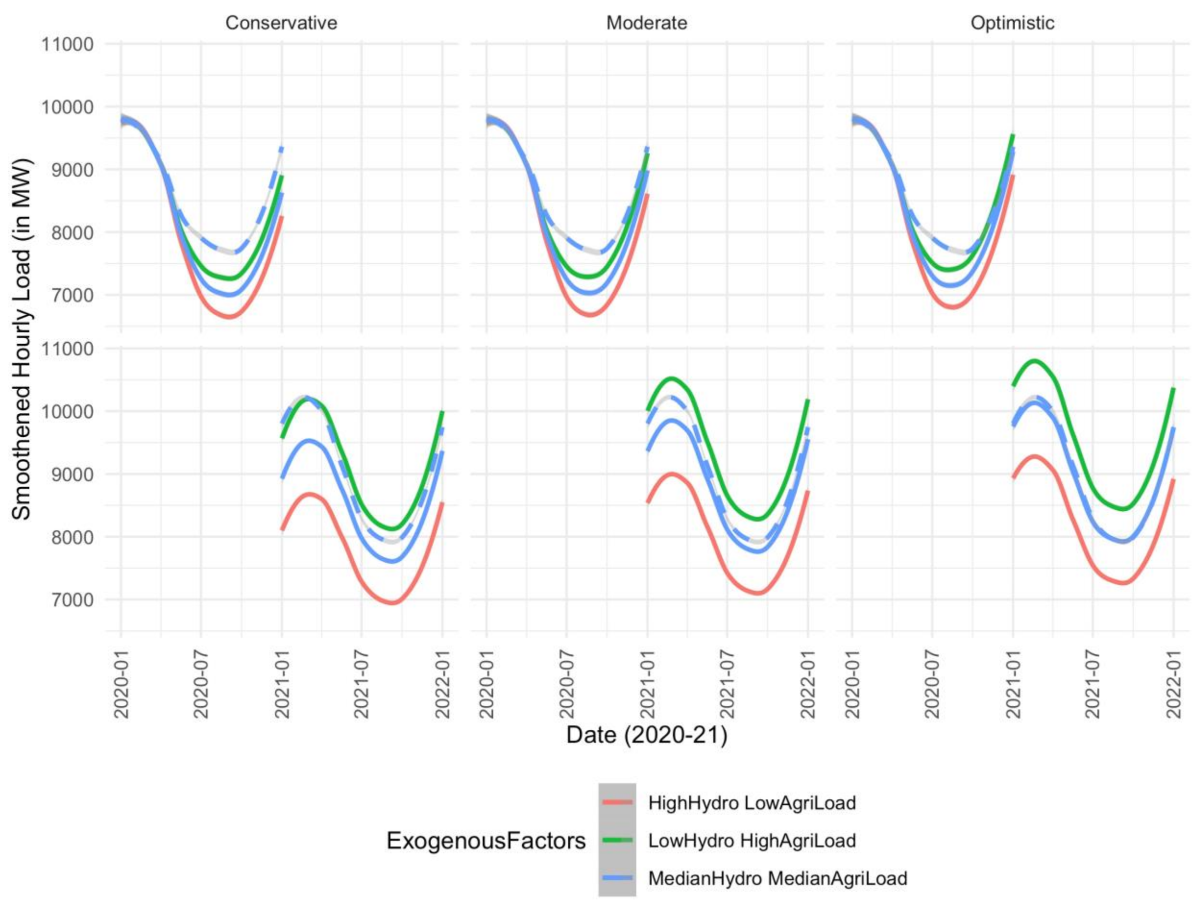

Figure 4.1 Demand scenarios for calendar years 2020 and 2021 under different conditions. The dashed line represents Baseline-Without COVID scenarios, assuming Median Hydro and Median Agri Load

We determine that COVID-19 has a significant impact on electricity demand in 2020. All three COVID-19 scenarios fall below the baseline, regardless of the combination of exogenous factors. The consumption reduction for the entire calendar year ranges from zero in the optimistic scenario with high agricultural demand to 9% in the conservative scenario with low agricultural demand.

The demand reduction for the calendar year 2021 is much less clear. In fact, exogenous factors mostly drive demand uncertainties. With the exception of the conservative scenario, the baseline profile is almost indistinguishable from the intermediate combination of exogenous factors.

The differences in demand across the various scenarios lead to corresponding changes in the generation. Our model indicates that changes to generation occur primarily to thermal units, as can be seen in **Appendix Figure D1**; this is to be expected as thermal units comprise the largest share of generation, and have the highest range of variable costs across all technology groups making them the marginal units.

4.2 Financial Impacts on Discoms

In **Figure 4.2**, we show the revenue from energy sold in INR Crores. Again, the above panel shows the 2020 outcome and the below panel shows the 2021 outcome. As the figure shows, in 2020 all three COVID-19 scenarios show revenue well below the baseline regardless of exogenous factors. The baseline revenue for 2020 is INR 46,329-47,395 Crores, whereas the revenues in the COVID-19 scenarios range from INR 42,729-45,025 Crore. The contrast to 2021 is clear, as the optimistic scenario shows very similar revenue patterns to the baseline while the decrease in the conservative and moderate scenarios is more substantial. Detailed numbers for all scenarios are available in **Appendix Tables D2-D3**.

The underlying factors causing change in revenues are clearer when we examine revenues by consumer category across the 9 scenarios. This is illustrated in **Appendix Figure D2**. In 2020, we see that the biggest drivers of uncertainty in reduction of revenues are the consumption from industrial and commercial consumer segments. In 2021, however, the largest uncertainty comes from agricultural load.

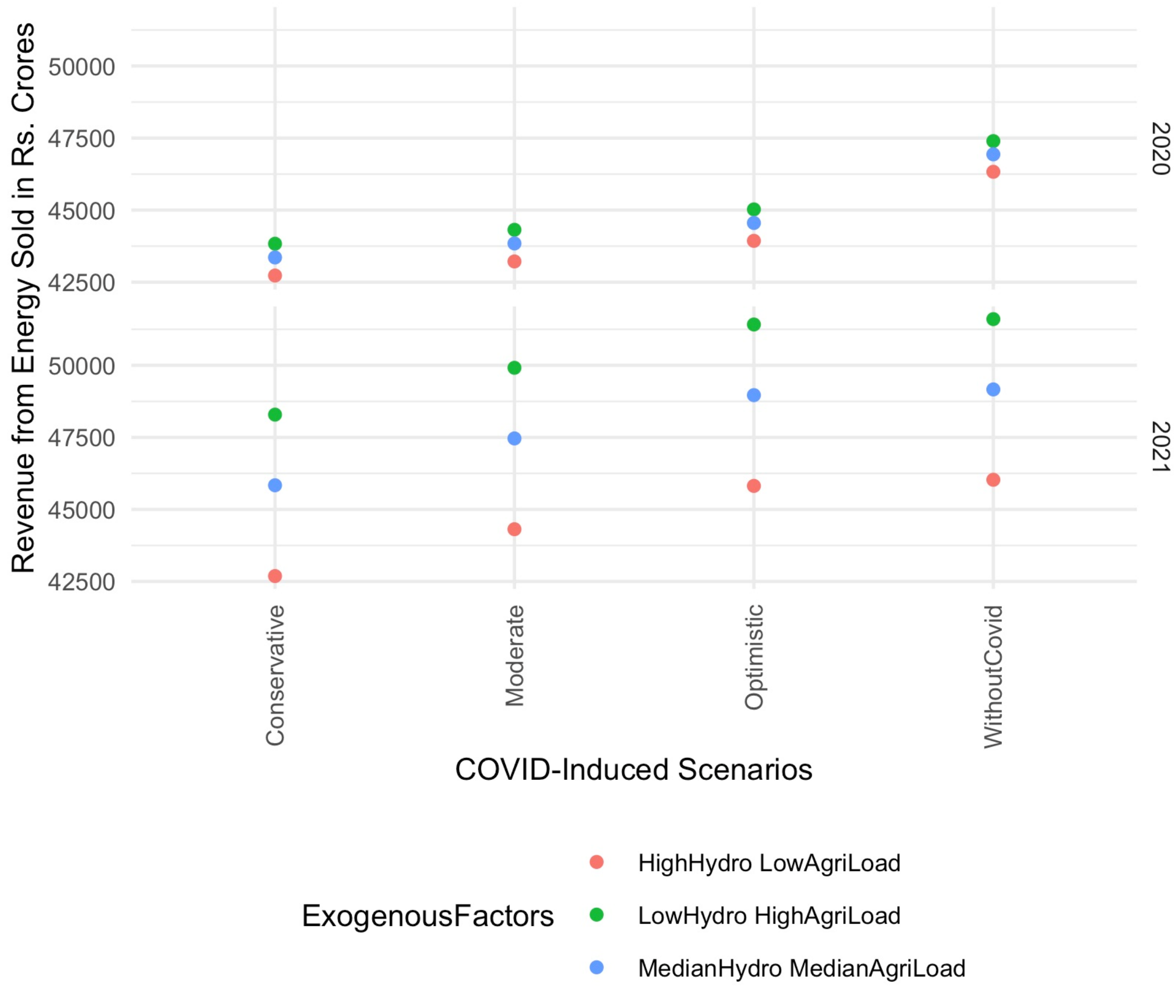

Figure 4.2 Discom revenue from energy sold.

As shown in **Figure 4.3**, the effect of COVID-19 on total generation costs is relatively modest in 2020. In the baseline scenario, total costs range from INR 51,107-53,097 Crore. In the COVID-19 scenarios, the range goes from INR 49,899-52,424 Crore. A key reason here is that only variable costs change with COVID-19. Both fixed costs and non-generation costs remain unchanged. Indeed, the percentage change in variable cost is important: compared to the baseline scenario, the costs decrease by INR 733 Crores (3.1%) in the optimistic scenario to INR 1069 Crores (4.6%) in the conservative scenario with intermediate exogenous conditions. As shown in **Appendix Figure D3**, all the variation in costs comes from variable costs, whereas fixed and non-power purchase costs remain unchanged.

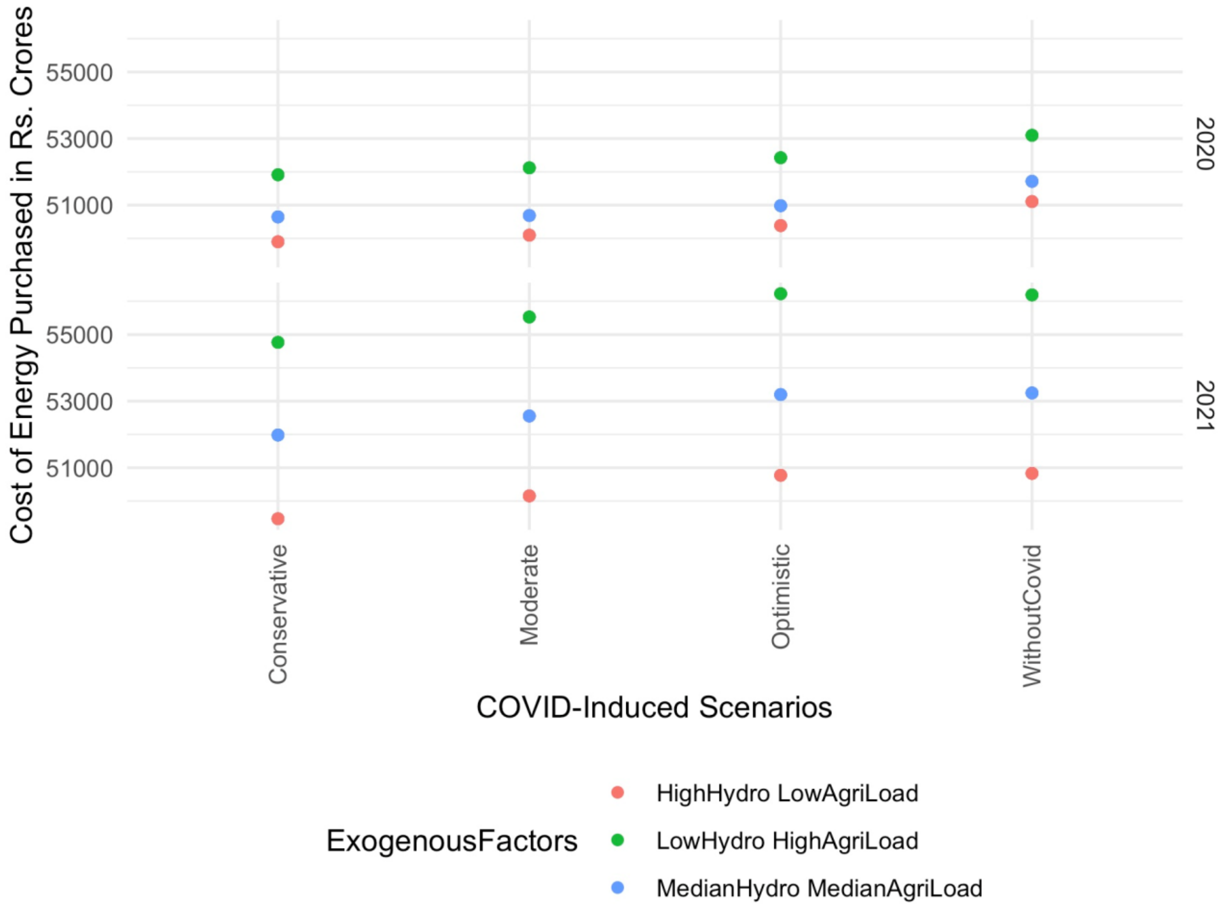

Figure 4.3 Cost incurred to discom for energy purchased.

In 2021, we again see little difference between the baseline and the optimistic scenarios. The moderate and conservative scenarios produce significant cost reductions, however, as the COVID-19 demand shock continues to linger. The greater variation in 2021 depending on exogenous conditions is an artifact of us having data for the first months of 2020. In 2021, a lot of the uncertainty is driven by the high variation in agricultural demand.

Figure 4.4 shows the discom profits. As the graph shows, in 2020 profits suffer significantly. The scenarios without COVID-19 show losses around INR 5,000 Crore, whereas the loss range for the COVID-19 scenarios runs from about INR 6,500-8,000 Crore. Therefore, the *additional* losses due to COVID-19 range from INR 1500-3000 crores.

In 2021, the differences are similar, as the losses fall between INR 4,000-5,000 Crore in the baseline scenarios and reach INR 6,000-7,000 Crore even in the conservative COVID-19 scenario. The additional losses due to COVID-19 are approximately INR 200-2,000 Crore.

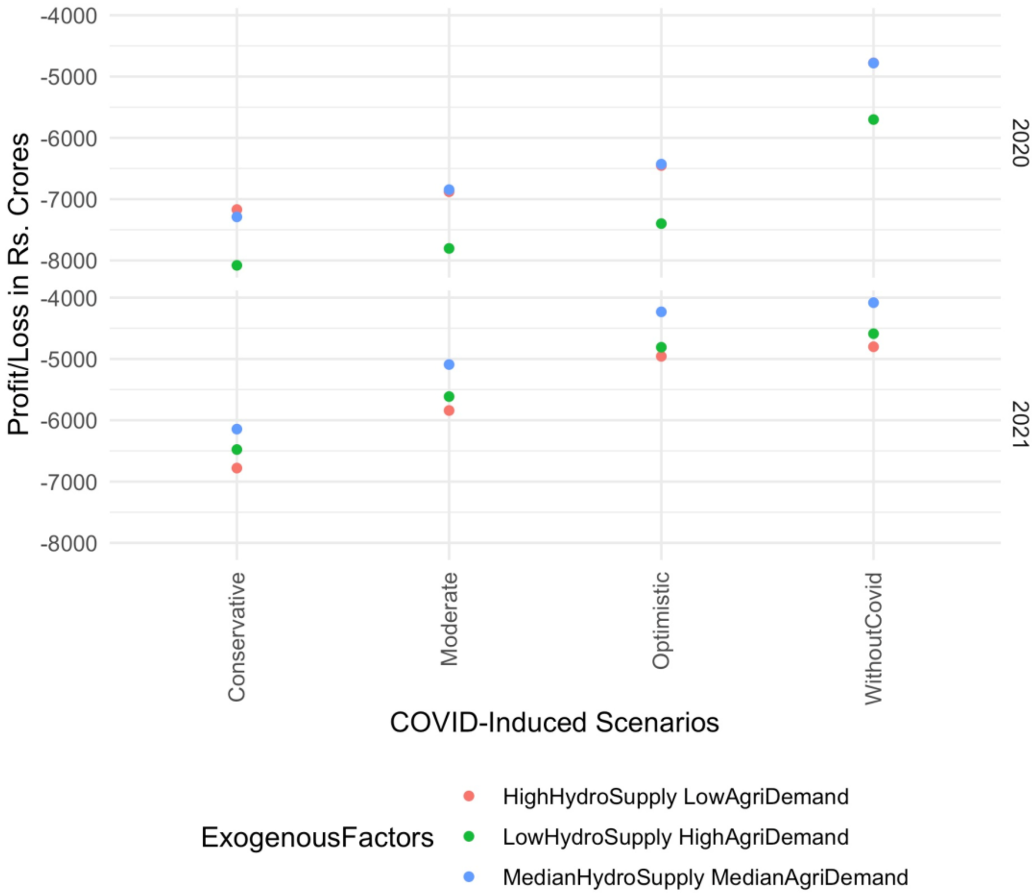

Figure 4.4 Discom profits from energy sold.

Finally, **Figure 4.5** shows the profits for each individual discom by scenario (top panel) and consumer category (bottom panel). As the figures show, the discom losses are heavily focused on BESCOM, which is not only the largest, but also has a high dependence on commercial and industrial revenue (25% and 24% of total BESCOM revenue, respectively, in 2019, before COVID-19). The figure also shows that for BESCOM in particular, agricultural load (which leads to losses of close to INR 4000 Crore) is massively subsidized by commercial and industrial load (which account for profits of about INR 3000 Crore, even in the Without-COVID scenario). The other discoms are therefore less sensitive to COVID-19 because subsidized agricultural load plays a bigger role than for BESCOM. For details on revenue, cost of generation, and validation, see **Appendix Section F**.

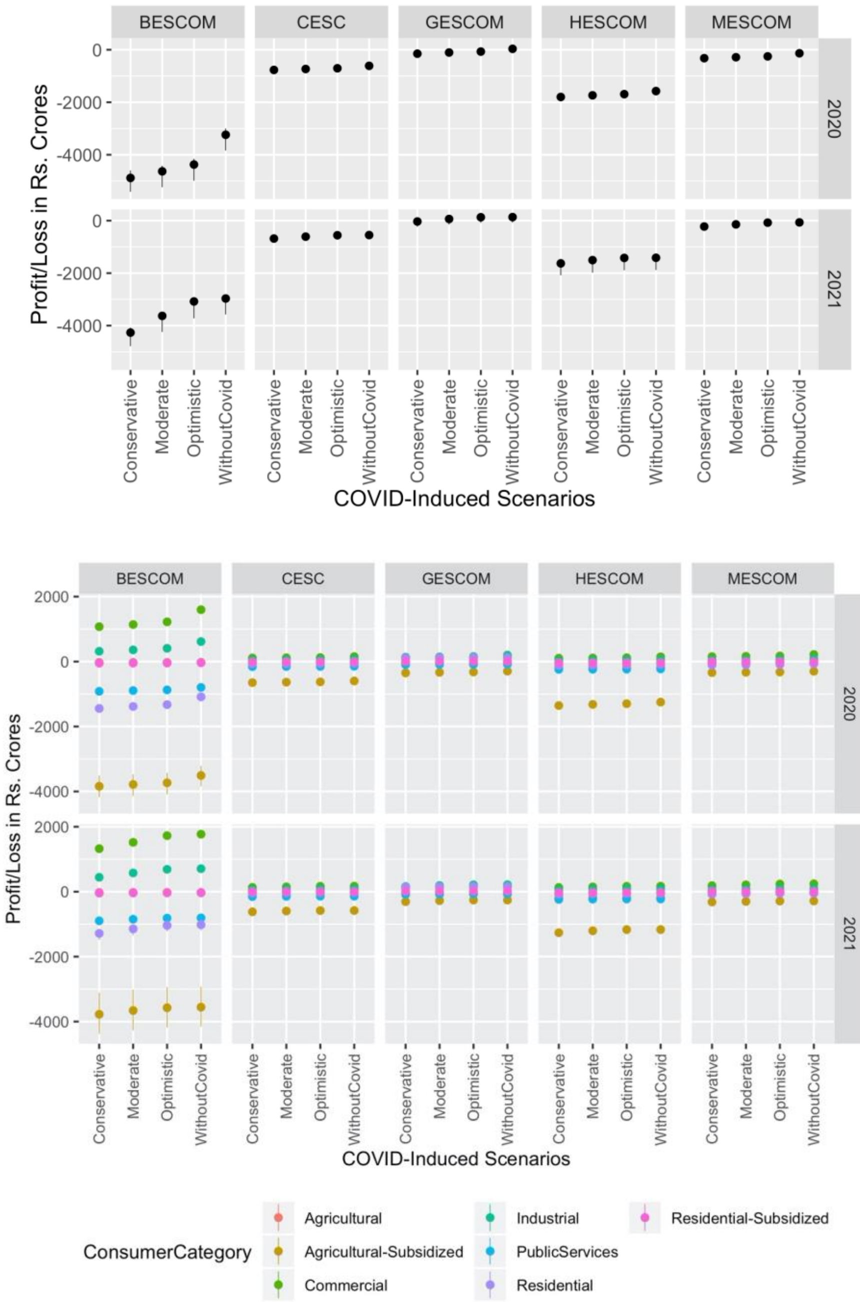

Figure 4.5 Discom profits/losses by scenario (top) and by consumer category (bottom). Error bars represent variation due to exogenous factors.

4.3 Evaluation of Policy Options

We next turn to possible policy options to mitigate discom losses. In **Figure 4.6**, we explore the impacts of increasing agricultural subsidies and residential tariffs. The panels on the left show the baseline profit scenarios, the middle panels illustrate the effect of increased agricultural subsidies from INR 5.7 to 6.9. / kWh, and the right panels show the combination of increased agricultural subsidies and increased residential tariffs from INR 7.3 to 9 / kWh.

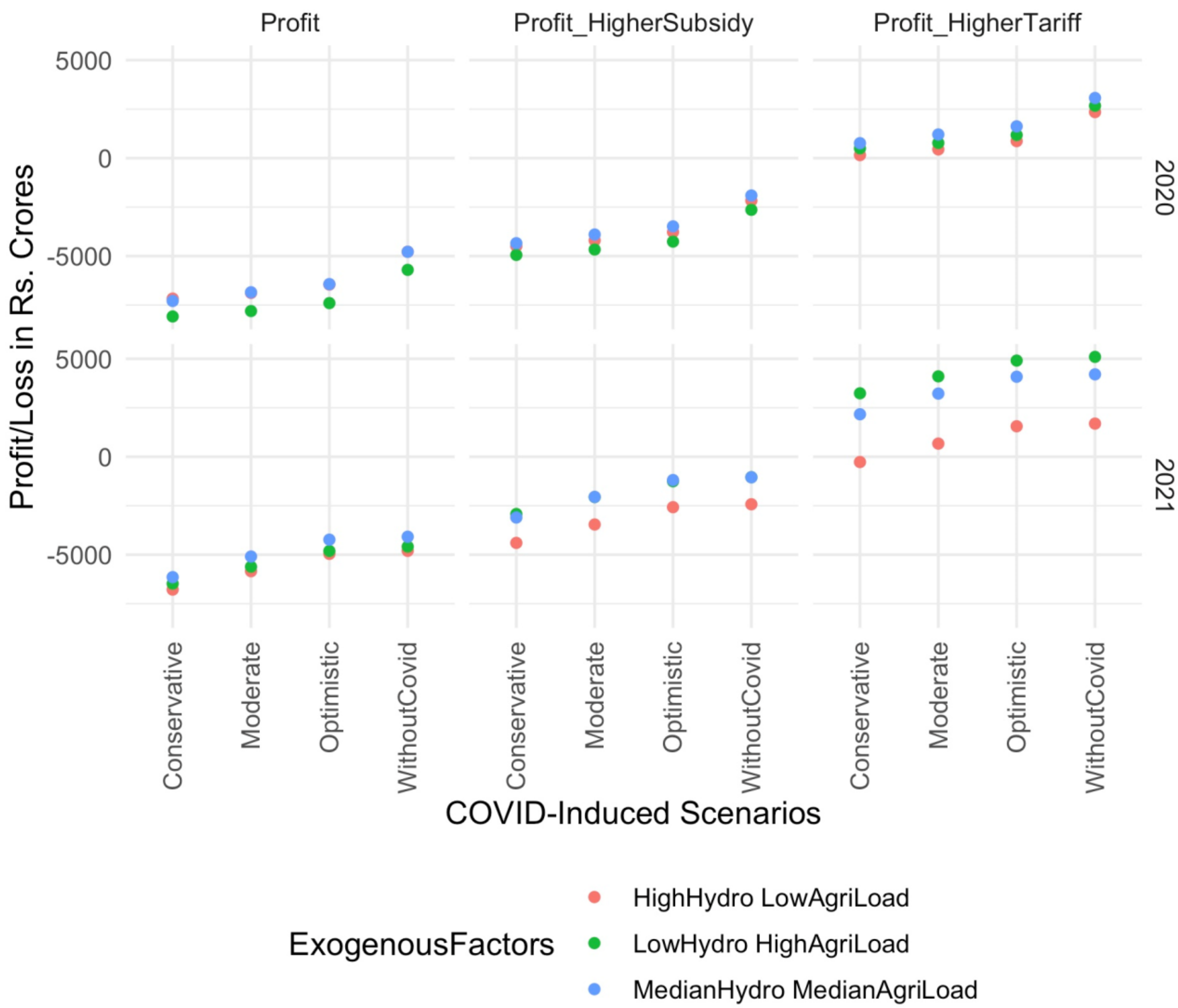

Figure 4.6. Policy options: increase tariffs or subsidies.

As the figure shows, both policy options provide substantial relief to the discoms. With higher agricultural subsidies, losses do not exceed INR 5,000 Crore in any scenarios either year. Notably, in both 2020 and 2021, increased agricultural subsidies alone fully offset the marginal COVID-19 losses. Adding higher residential tariffs, profits actually turn positive in most scenarios. (It should be noted, of course, that these profits come at the expense of either taxpayers or residential electricity consumers – they do not represent welfare gains.)

In **Figure 4.7**, we consider the possibility of reversing fixed costs in power purchase agreements to those in financial year 2019-2020[5]. As the graph shows, this reversal would also provide substantial relief. In both 2020 and 2021, COVID-affected profits would be approximately equal or significantly better than baseline profits under projected, higher fixed costs. Nonetheless, discoms would remain in loss territory.

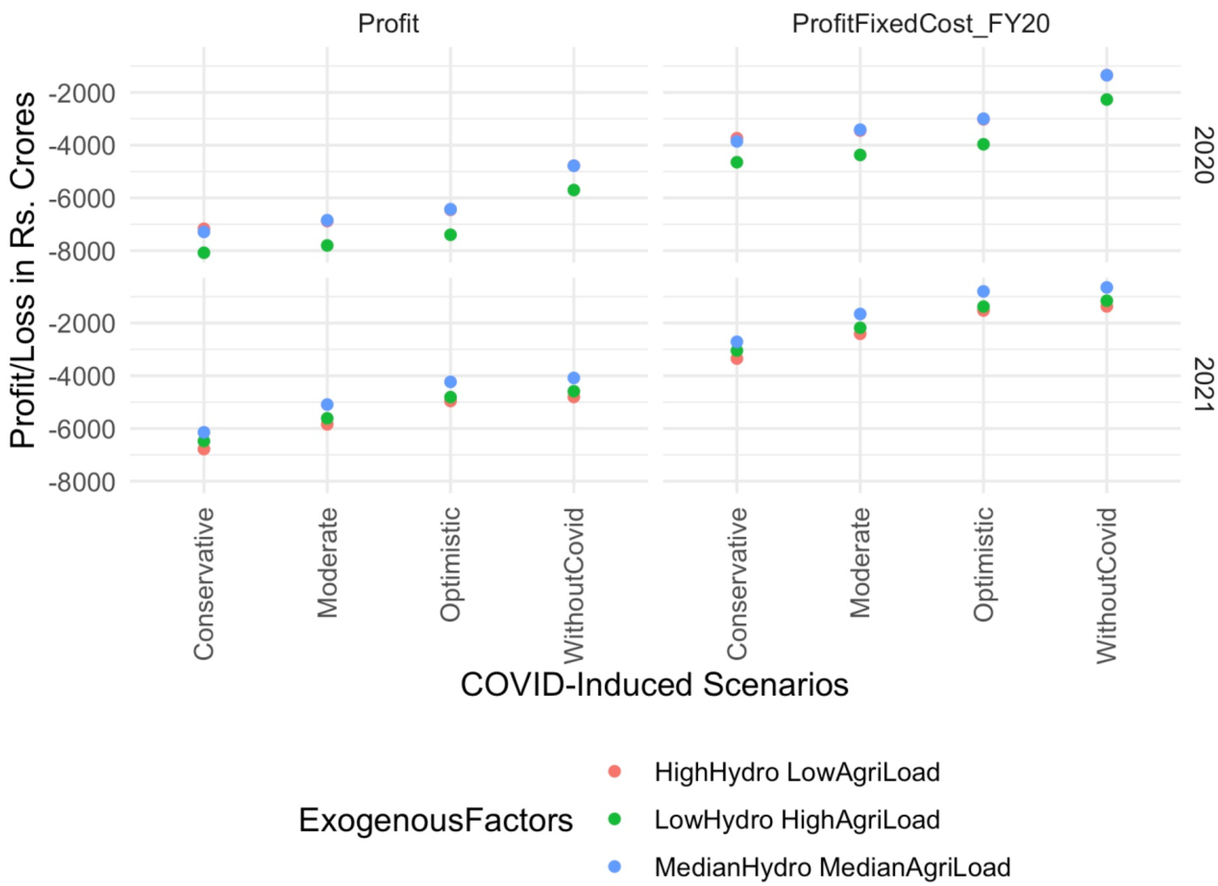

Figure 4.7 Policy options: reduce fixed costs.

In **Figure 4.8**, we further assess the benefits to each individual discom of improving effective revenue (INR / kWh) by 10% in each consumer category. We use a uniform percentage increase to compare sensitivity across categories. The figure shows that for the discom that suffers the most from COVID-19, BESCOM, residential revenue improvements are potential suitable policy option. Agricultural revenue improvements do less to help, though mostly because there is less agricultural revenue to begin with. Industrial and commercial revenue improvements could be

[5] This reverting of fixed costs to 2019 values does not have an impact on the availability of power plants. This is because the increase in fixed costs is driven primarily by YTPS units 2 and 3, and despite an indication in the tariff filings that YTPS units 2 and 3 will charge fixed costs, generation data shows that YTPS units 2 and 3 have not been operational. We assume in all scenarios that only YTPS unit 1 is operational, although fixed costs are being charged, as per proposed tariff filings.

very difficult to implement because of price elasticity and the hardship caused by COVID-19. Other discoms, in contrast, would benefit the most from agricultural revenue increases.

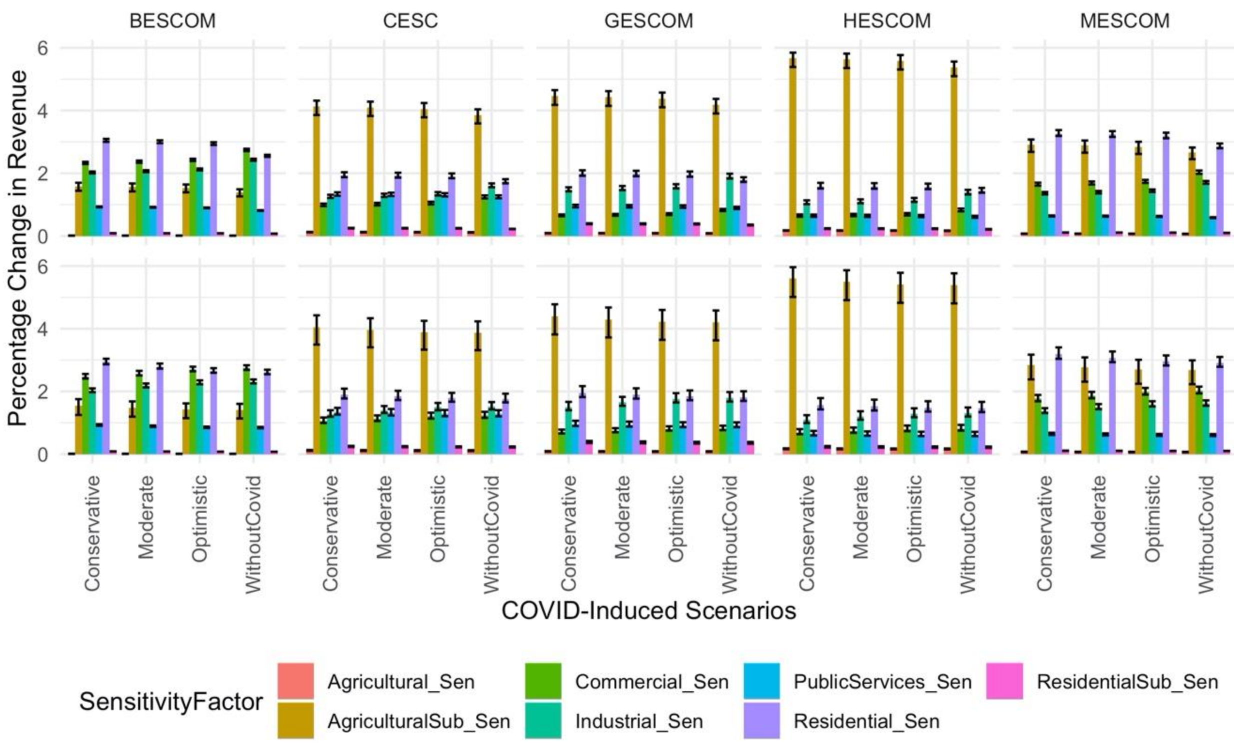

Figure 4.8 Change in revenue (%) by consumer category with a 10% effective revenue increase per kWh. Error bars represent variations due to exogenous factors of agri Load and hydro supply. See Appendix Figure F6 for total revenue increases in INR Crores and Figure F7 for total change in profits.

4.4 Verification and Validation

Validation is the process of evaluating the model's fit-for-purpose. For this study, we perform validation in two steps. First, we validate whether we reproduce historical results of generation by plant, total costs, and total revenues for financial year 2019. In the second step, we discuss the comparisons of costs and revenues between our projections for calendar year 2020, with the discoms' projections for the financial year 2021.

Model outputs compare reasonably well with the available data for costs and revenues for FY19, as shown in **Figure 4.9**. The largest difference comes from the variable cost component; our model's estimates are lower than actual by approximately INR 4,000 Crores; explained largely by the model's higher use of thermal power from RTPS than actual. Our model's generation compares well the available data for generation for FY19, as illustrated in **Appendix Figures E1-E2**. The largest difference at the plant level was revealed for the power station at RTPS; actual generation from RTPS was far less (by appr. 30%) than model generation from RTPS for the same period; this is likely explained by reduced availability of RTPS in reality, which was not accounted for in the model. Furthermore, our model estimates revenues to be slightly (3%) higher than actual, causing profit to be close to zero.

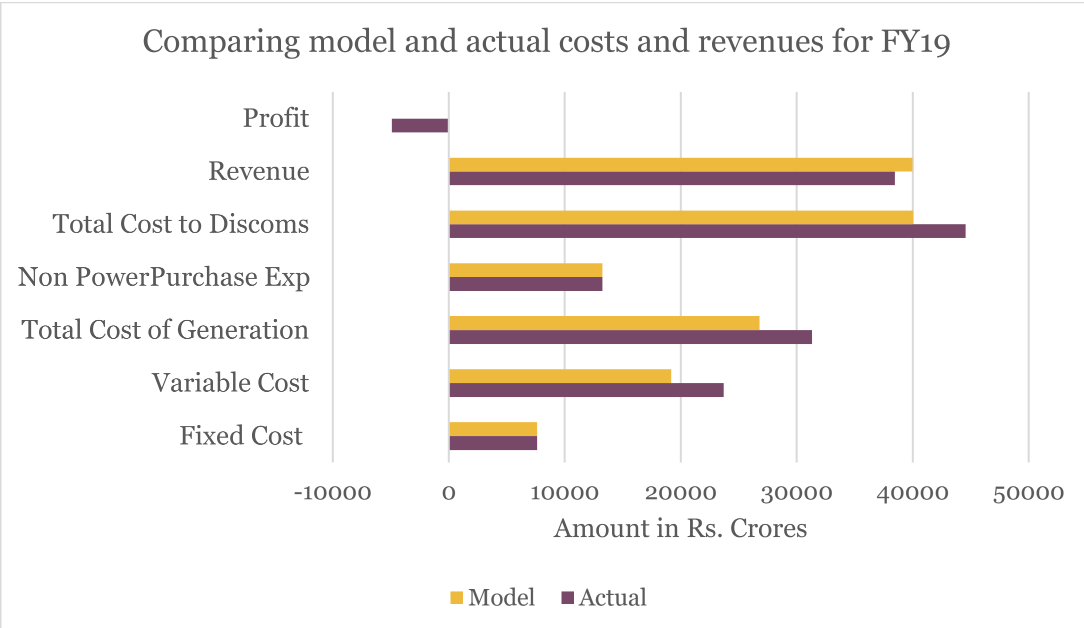

Figure 4.9 Comparing model and actual costs and revenues for financial year 2019.

We also juxtapose our model results for the calendar years 2020 to the proposed costs and revenues for financial year 2020-21 available in the 2020 Tariff filings. This comparison is not one to one, and is only indicative, as the time periods differ by a quarter, consequently having correspondingly different overall demand profiles. These tariff filings were uploaded in January 2020, without accounting for COVID, which makes the "Without COVID – Median Hydro and Agri Load" scenario most appropriate for comparison.

To the extent that proposed tariff filings are comparable to the costs in the calendar year, **Figure 4.10** indicates that our model underestimates variable costs by about INR 1,700 Crores for the same reason described above (model assumes greater RTPS generation than actual), and overestimates revenues by about 3%, leading to a lower losses than expected.

We present the break-up of the revenues by consumer category in **Appendix Figure E3**. The model seems to estimate higher revenue than in the tariff filings, particularly from commercial and industrial consumer categories. This difference is likely caused by our assumptions of Effective Revenue per Unit, which do not account for graded tariff slabs that increase with consumption.

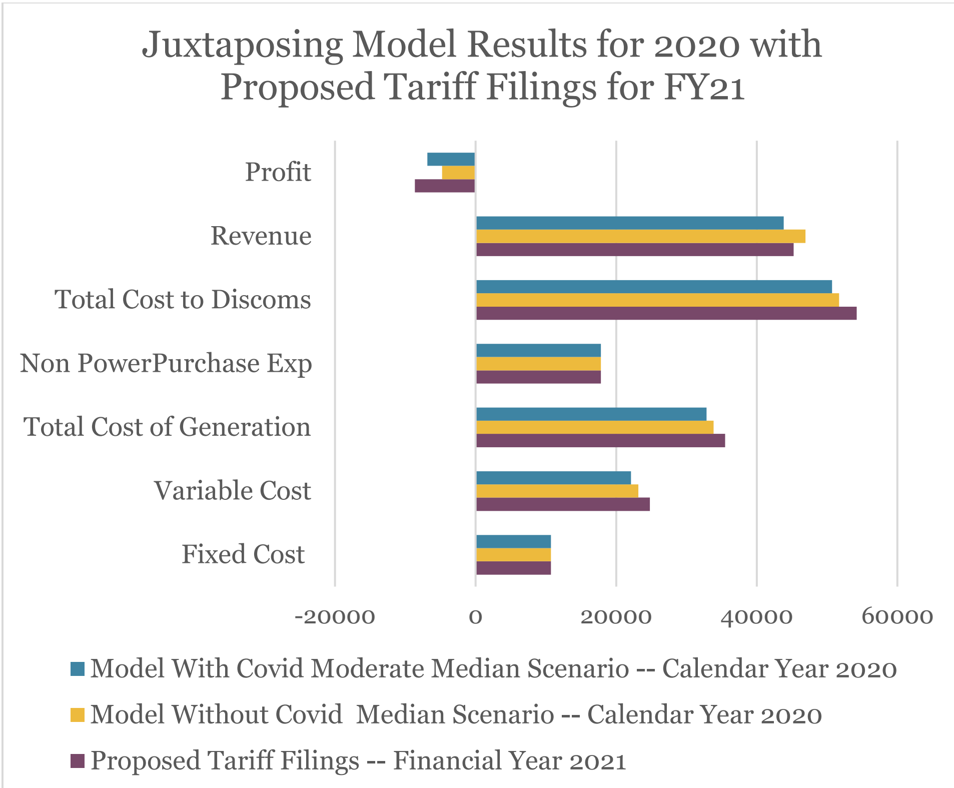

Figure 4.10 Comparing model results for 2020 with proposed costs and revenues for financial year 2020-21.

Notably, differences between modeled and actual historical outcomes remain consistent across all scenarios. Although the model sometimes slightly deviates from reality, this gap does not generate differences in outcomes between different model-based runs. Therefore, we have high confidence in the differences between revenues in various scenarios, although in absolute terms, we may slightly (3%) overestimate revenues across all scenarios (by 3%). **Appendix Figures E4-E5** illustrate historical, proposed, and modeled revenues.

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CONCLUSION

In this report, we have analyzed the effect of COVID-19 on the Karnataka power sector. We have evaluated a range of plausible, COVID-induced demand scenarios under different hydro production, agricultural demand, and power market price conditions. These scenarios have generated estimates for COVID-19 impact on discom revenue, total cost, and profits. We have also considered increased agricultural subsidies, higher residential tariffs, and lower fixed costs as possible policy intervention.

The results show that without a policy intervention, COVID-19 will have a significant impact on discom revenue and profit. Intuitively, the COVID-19 impact is driven by a substantial decrease in the most revenue-generating consumer categories, namely, commercial and industrial. Although residential and agricultural demand is not significantly affected by COVID-19, the financial impact is substantial because commercial and industrial consumers generate a disproportional share of discom revenue today. Considering that Karnataka's state revenue for FY 2021 is INR 2.33 Lakh Crore, a typical loss from COVID-19 of about INR 2,000 Crore is almost 1% of the entire state revenue. Compared to a deficit of INR 23,103 Crore, the discom profit reduction is almost 9% of the total. Results per discom indicate that much of the losses due to COVID-19 are accrued by BESCOM, due to their high cross-subsidization between agricultural consumers on the one hand, and commercial and industrial consumers on the other.

On the other hand, policy interventions can mitigate the impact. One option is to increase agricultural subsidies. While this approach would not directly mitigate the COVID-19 impact, it would provide badly needed relief given the large share of agricultural in total electricity consumption. The downside of this approach, of course, is that it passes the cost to taxpayers through additional government spending. It also provides less relief to the worst hit discom, BESCOM, which is heavily dependent on commercial, industrial, and residential consumers.

Increasing residential tariffs is an appealing option because it does not add to the state government's fiscal troubles. However, it may run into political obstacles, as increasing residential tariffs imposes a highly visible, direct cost on voters. The welfare impacts of higher residential tariffs on residential consumers also call for additional research.

The third option we consider is renegotiated power purchase agreements for lower fixed costs. A full renegotiation of power purchase agreements is probably not a viable option, but we note a recent increase in fixed costs for some power plants and consider the reversal of fixed costs to the previous financial year's level. This policy would also provide significant relief, though at the expense of generators.

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DATA

The supporting data for this brief can be found at https://doi.org/10.7910/DVN/U7RXSV.

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APPENDIX

A1. Data

A: Power Plant Data and Assumptions

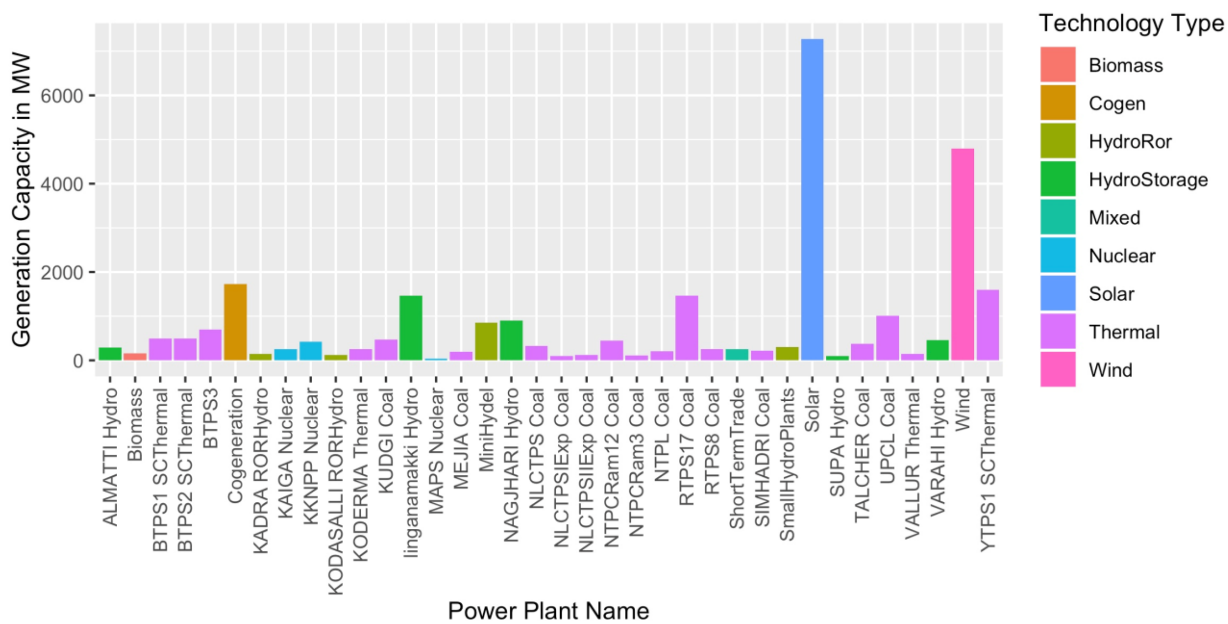

Figure A1: Generation Capacity in Karnataka by Power Plant Name and Technology Type (in MW)

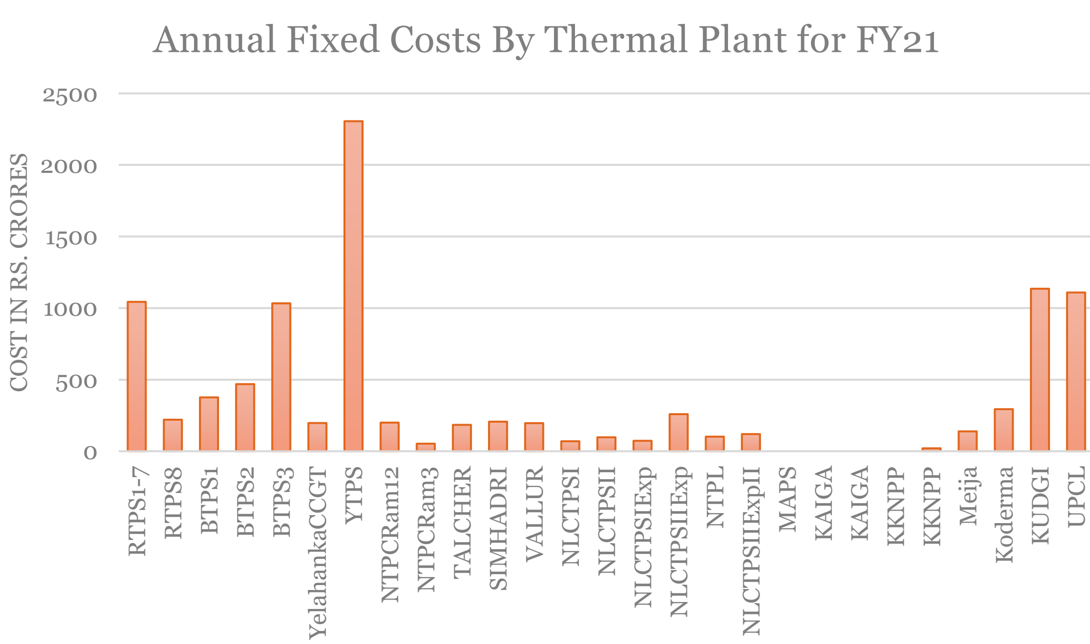

Figure A2: Fixed cost charges in Karnataka by Power Plant Name for FY 21 (in Rs. Crores). Source: Tariff filings 2020

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Financial Year	Consumer Category	Annual Consumption In MU	Annual Revenue	Effective Revenue Per Unit (INR)
21	Agricultural	868.23	362.14	4.17
21	Agricultural-Subsidized	23900.35	13593.84	5.69
21	Commercial	7590.18	8423.19	11.10
21	Industrial	10127.00	9294.04	9.18
21	PublicServices	6015.43	3612.76	6.01
21	Residential	13173.33	9651.06	7.32
21	Residential-Subsidized	909.54	660.49	7.26

Table A1: Consumer categories, annual consumption, revenue, and effective revenue per unit.

Category	*Consumer Category*	*Wider Consumer Category*
LT-1	BhagyaJyothi Domestic	Residential
LT-2	All Electric Homes & Pvt. Educational Institutions	Residential
LT-3	Commercial	Commercial
LT-4a	Irrigation Pump sets-upto 10 HP	Agricultural
LT-4(b) & (c)	sets-More than 10 HP & Horticulture	Agricultural
LT-5	LT Industries	Industrial
LT-6	Water Supply	Public Service
LT-6	Street Lights	Public Service
LT-7	Temporary Power &Advert-	Commercial
HT-1	HT- Water Supply	Public Service
HT-2a	HT- Industries	Industrial
HT-2b	HT Commercial	Commercial
HT-2c	Institutions / Hospitals	Commercial
HT-3(a) & (b)	HT Irrigation & LI Schemes	Agricultural
HT-4	Residential Apartments	Residential
HT-5	Temporary Power	Commercial

Table A2: Conversion from voltage category as specified in tariff filings to wider consumer category assumed for model analysis

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B: Scenarios

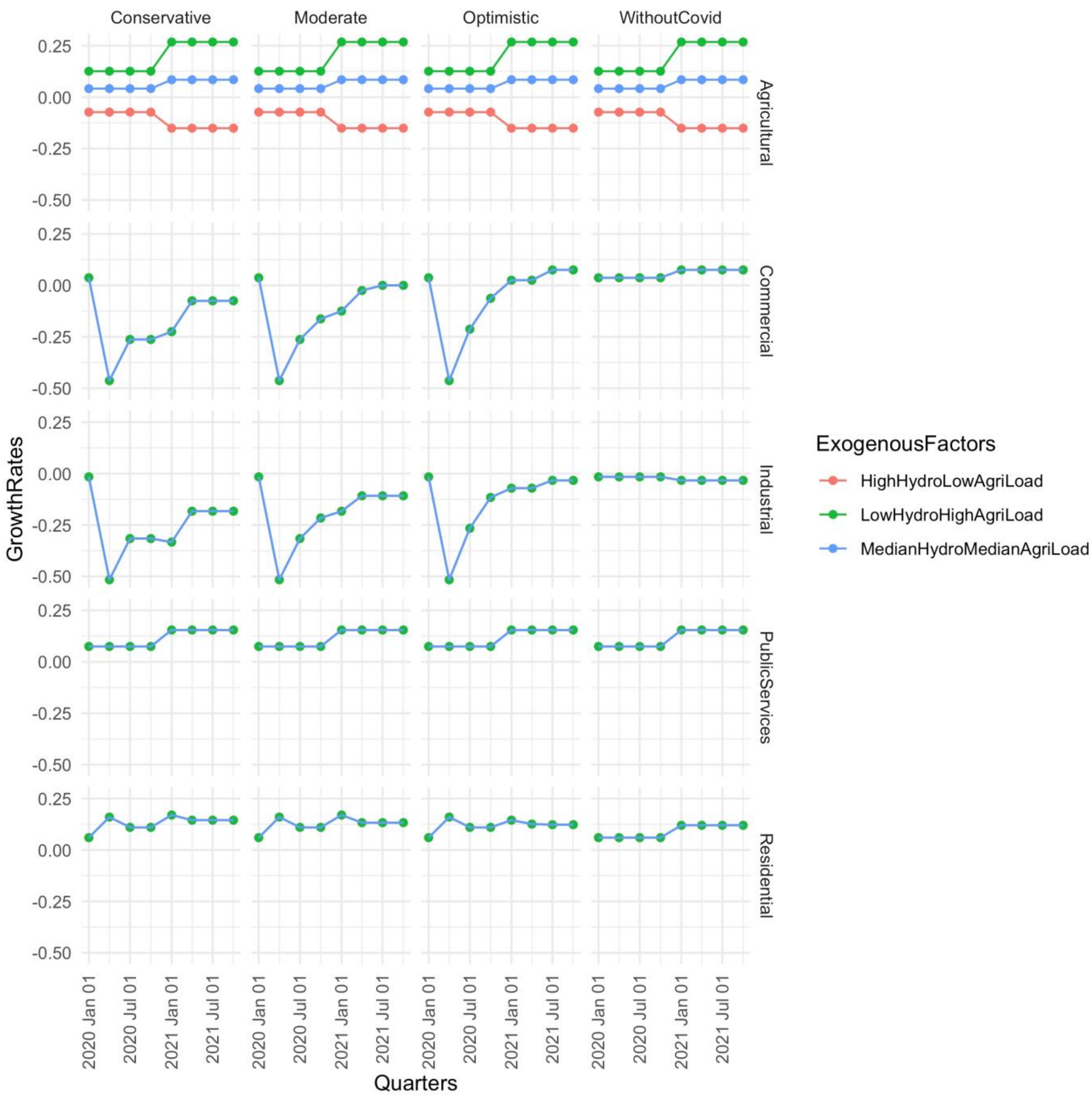

Figure B1: Growth rate assumptions for 2020 and 2021 by quarters and by consumer category, relative to 2019 demand values

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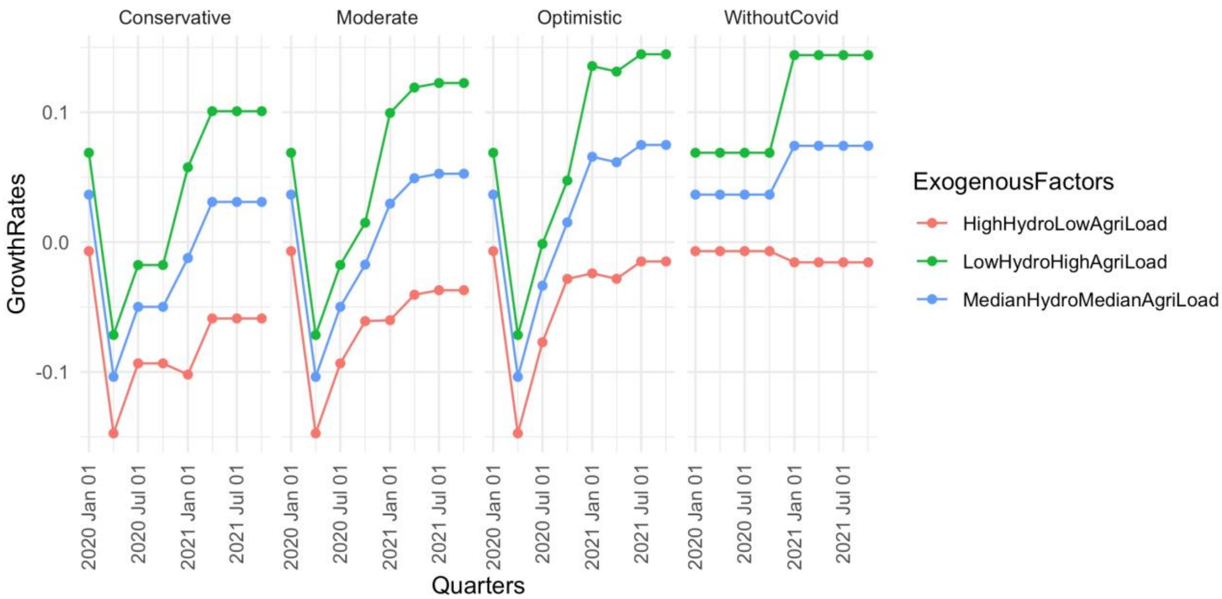

Figure B2: Overall growth rates for 2020 and 2021, relative to 2019 demand

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C: Methods

Plant Name	Capacity in MW	Single Part Tariff in INR Per kWh
Solar Pavagada	1000	2.88
Solar Rooftop	274	6
Solar Subsidized	2000	0
Solar Utility Scale	4000	5
Wind Utility Scale	4800	3.6

Table C1: Assumptions for solar variable cost. Source: Tariff filing 2020 for BESCOM

D: Results

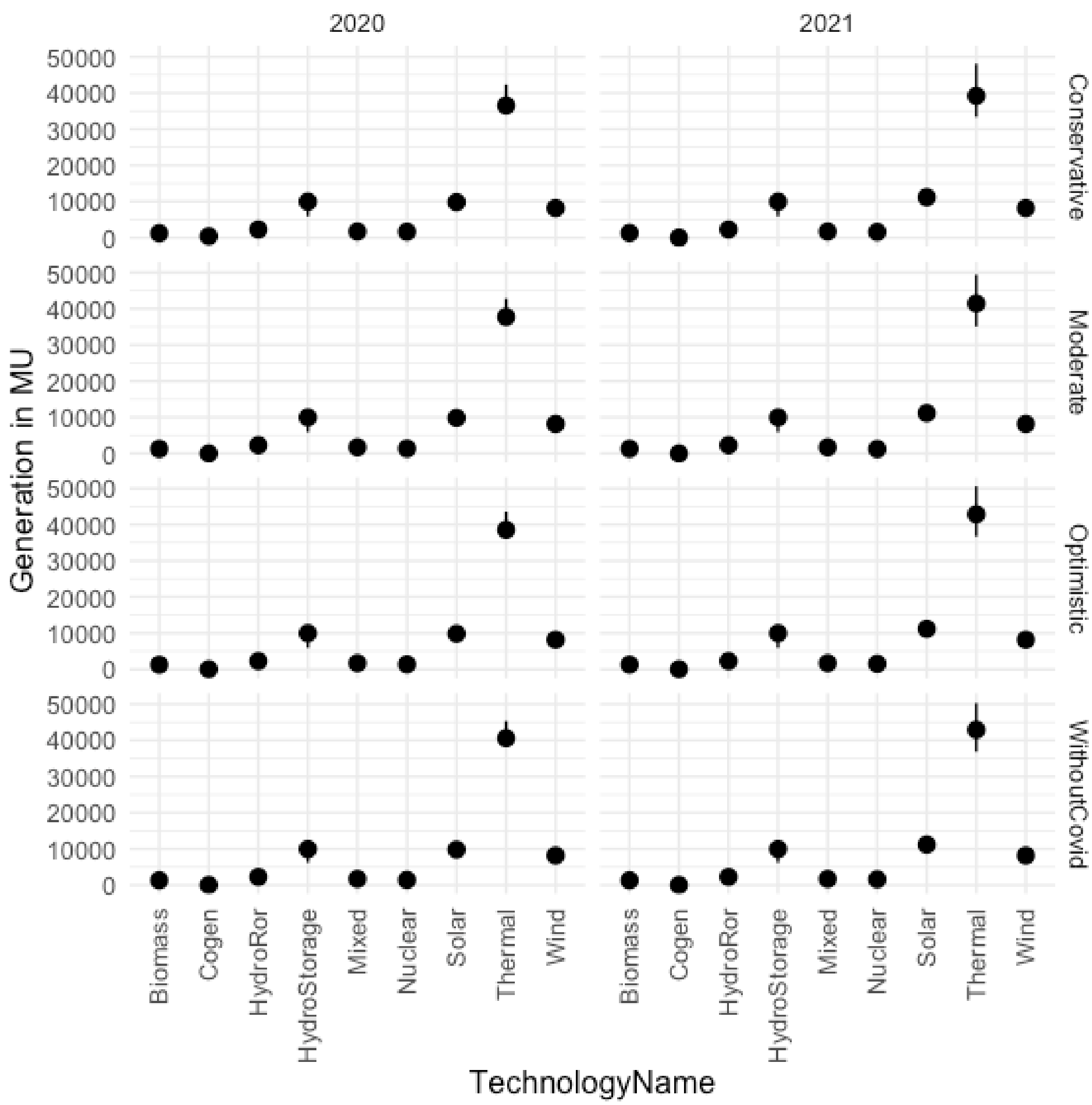

Figure D1: Annual Generation by Technology in MU.

Covid Induced Scenario	Exogenous Factors	Year	Annual Load in MU
Conservative	HighHydro LowAgriLoad	2020	69643.9302
Conservative	MedianHydro MedianAgriLoad	2020	71385.8486
Conservative	LowHydro HighAgriLoad	2020	72675.1425
Moderate	HighHydro LowAgriLoad	2020	70209.0052
Moderate	MedianHydro MedianAgriLoad	2020	71950.9236
Moderate	LowHydro HighAgriLoad	2020	73240.2175
Optimistic	HighHydro LowAgriLoad	2020	71035.9157
Optimistic	MedianHydro MedianAgriLoad	2020	72777.8341
Optimistic	LowHydro HighAgriLoad	2020	74067.128
WithoutCovid	HighHydro LowAgriLoad	2020	73234.1853
WithoutCovid	MedianHydro MedianAgriLoad	2020	74976.1037
WithoutCovid	LowHydro HighAgriLoad	2020	76265.3976
Conservative	HighHydro LowAgriLoad	2021	68367.6458
Conservative	MedianHydro MedianAgriLoad	2021	74973.7656
Conservative	LowHydro HighAgriLoad	2021	80114.4823
Moderate	HighHydro LowAgriLoad	2021	70244.5084
Moderate	MedianHydro MedianAgriLoad	2021	76850.6282
Moderate	LowHydro HighAgriLoad	2021	81991.3449
Optimistic	HighHydro LowAgriLoad	2021	71921.7515
Optimistic	MedianHydro MedianAgriLoad	2021	78527.8713
Optimistic	LowHydro HighAgriLoad	2021	83668.588
WithoutCovid	HighHydro LowAgriLoad	2021	72293.7771
WithoutCovid	MedianHydro MedianAgriLoad	2021	78899.8969
WithoutCovid	LowHydro HighAgriLoad	2021	84040.6136

Table D1: Annual Consumption in MU

Covid Induced Scenario	Exogenous Factors	year	Cost To Discom In RsCr	Revenue To Discom In RsCr	Profit In RsCr
Conservative	HighHydro LowAgriLoad	2020	49899.0	42729.0	-7170.0
Conservative	LowHydro HighAgriLoad	2020	51912.6	43832.5	-8080.1
Conservative	MedianHydro MedianAgriLoad	2020	50646.1	43356.6	-7289.6
Moderate	HighHydro LowAgriLoad	2020	50097.6	43218.2	-6879.4
Moderate	LowHydro HighAgriLoad	2020	52120.8	44316.8	-7804.0
Moderate	MedianHydro MedianAgriLoad	2020	50688.4	43842.9	-6845.5
Optimistic	HighHydro LowAgriLoad	2020	50385.0	43933.2	-6451.9
Optimistic	LowHydro HighAgriLoad	2020	52423.8	45024.7	-7399.1
Optimistic	MedianHydro MedianAgriLoad	2020	50982.7	44553.7	-6429.0
WithoutCovid	HighHydro LowAgriLoad	2020	51106.9	46329.0	-4777.9
WithoutCovid	LowHydro HighAgriLoad	2020	53097.2	47395.2	-5702.0
WithoutCovid	MedianHydro MedianAgriLoad	2020	51715.6	46935.1	-4780.5
Conservative	HighHydro LowAgriLoad	2021	49467.6	42687.6	-6780.0
Conservative	LowHydro HighAgriLoad	2021	54767.5	48289.6	-6477.8
Conservative	MedianHydro MedianAgriLoad	2021	51982.5	45838.1	-6144.4
Moderate	HighHydro LowAgriLoad	2021	50154.0	44312.9	-5841.1
Moderate	LowHydro HighAgriLoad	2021	55528.6	49914.9	-5613.7
Moderate	MedianHydro MedianAgriLoad	2021	52554.7	47463.4	-5091.3
Optimistic	HighHydro LowAgriLoad	2021	50773.1	45815.8	-4957.3
Optimistic	LowHydro HighAgriLoad	2021	56227.3	51417.5	-4809.8
Optimistic	MedianHydro MedianAgriLoad	2021	53198.0	48966.2	-4231.8
WithoutCovid	HighHydro LowAgriLoad	2021	50830.5	46029.1	-4801.4
WithoutCovid	LowHydro HighAgriLoad	2021	56191.8	51603.8	-4588.0
WithoutCovid	MedianHydro MedianAgriLoad	2021	53246.5	49164.2	-4082.3

Table D2. Cost, Revenue, and Profit to discoms under different scenarios for 2020 and 2021

Covid Induced Scenario	Exogenous Factors	Year	Total Generation in MU	Fixed Cost in Rs Cr	Variable Costs in Rs Cr	Power Purchase Costs in Rs Cr	Non power purchase costs in Rs. Cr.	Total Costs in Rs Cr
Conservative	HighHydro LowAgriLoad	2020	69963.3	10727.0	21329.0	32056.1	17843.0	49899.0
Conservative	HighHydro LowAgriLoad	2021	68696.9	10727.0	20897.6	31624.6	17843.0	49467.6
Conservative	MedianHydro MedianAgriLoad	2020	71709.6	10727.0	22076.1	32803.2	17843.0	50646.1
Conservative	MedianHydro MedianAgriLoad	2021	75320.2	10727.0	23412.5	34139.6	17843.0	51982.5
Conservative	LowHydro HighAgriLoad	2020	73002.2	10727.0	23342.6	34069.6	17843.0	51912.6
Conservative	LowHydro HighAgriLoad	2021	80474.2	10727.0	26197.5	36924.5	17843.0	54767.5
Moderate	HighHydro LowAgriLoad	2020	70540.0	10727.0	21527.6	32254.6	17843.0	50097.6
Moderate	HighHydro LowAgriLoad	2021	70616.4	10727.0	21584.0	32311.1	17843.0	50154.0
Moderate	MedianHydro MedianAgriLoad	2020	72286.4	10727.0	22118.4	32845.4	17843.0	50688.4
Moderate	MedianHydro MedianAgriLoad	2021	77239.7	10727.0	23984.7	34711.7	17843.0	52554.7
Moderate	LowHydro HighAgriLoad	2020	73578.9	10727.0	23550.7	34277.8	17843.0	52120.8
Moderate	LowHydro HighAgriLoad	2021	82393.7	10727.0	26958.6	37685.6	17843.0	55528.6
Optimistic	HighHydro LowAgriLoad	2020	71384.0	10727.0	21815.0	32542.1	17843.0	50385.0
Optimistic	HighHydro LowAgriLoad	2021	72333.8	10727.0	22203.1	32930.1	17843.0	50773.1
Optimistic	MedianHydro MedianAgriLoad	2020	73130.3	10727.0	22412.7	33139.8	17843.0	50982.7
Optimistic	MedianHydro MedianAgriLoad	2021	78957.1	10727.0	24628.0	35355.0	17843.0	53198.0
Optimistic	LowHydro HighAgriLoad	2020	74422.9	10727.0	23853.8	34580.8	17843.0	52423.8
Optimistic	LowHydro HighAgriLoad	2021	84111.1	10727.0	27657.3	38384.3	17843.0	56227.3
WithoutCovid	HighHydro LowAgriLoad	2020	73511.0	10727.0	22536.9	33263.9	17843.0	51106.9
WithoutCovid	HighHydro LowAgriLoad	2021	72478.5	10727.0	22260.5	32987.6	17843.0	50830.5
WithoutCovid	MedianHydro MedianAgriLoad	2020	75249.6	10727.0	23145.6	33872.6	17843.0	51715.6
WithoutCovid	MedianHydro MedianAgriLoad	2021	79072.1	10727.0	24676.5	35403.5	17843.0	53246.5
WithoutCovid	LowHydro HighAgriLoad	2020	76536.4	10727.0	24527.2	35254.2	17843.0	53097.2
WithoutCovid	LowHydro HighAgriLoad	2021	84203.1	10727.0	27621.8	38348.8	17843.0	56191.8

Table D3. Generation and costs to discoms under different scenarios for 2020 and 2021

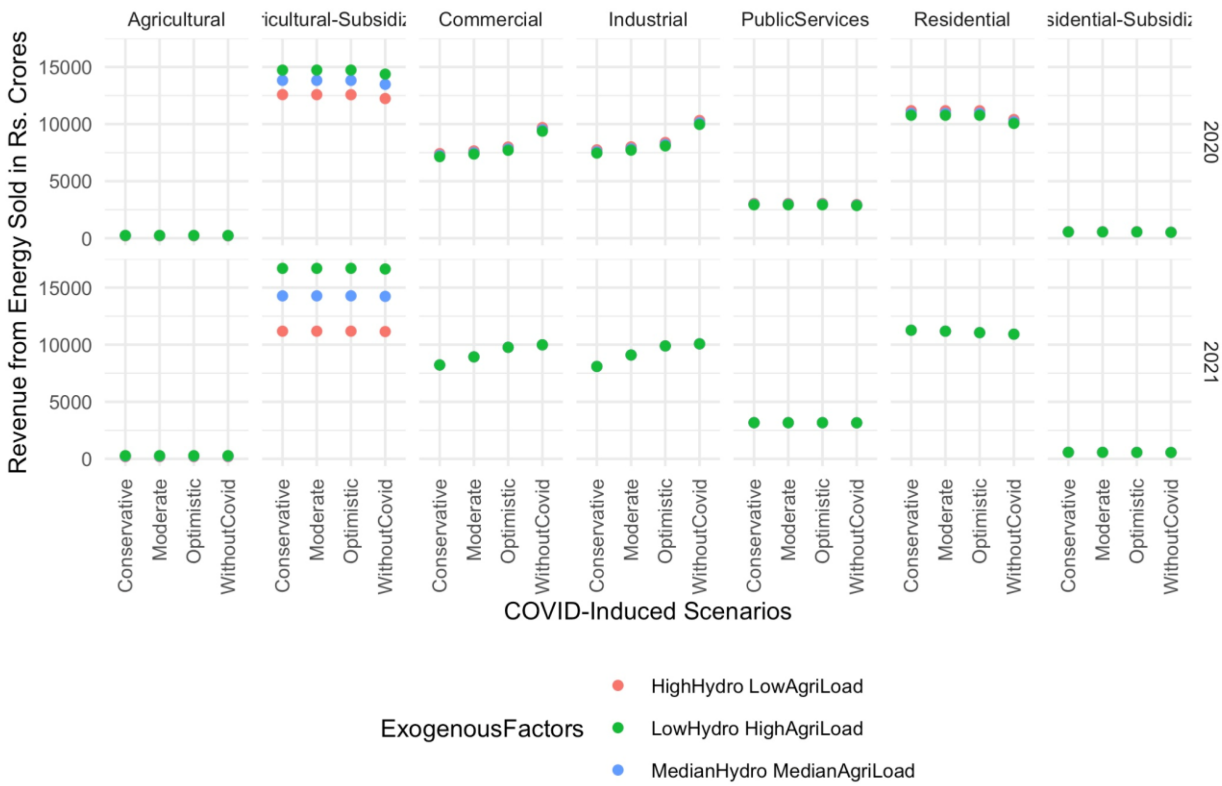

Figure D2: Revenue by consumer category across scenarios in INR Crore

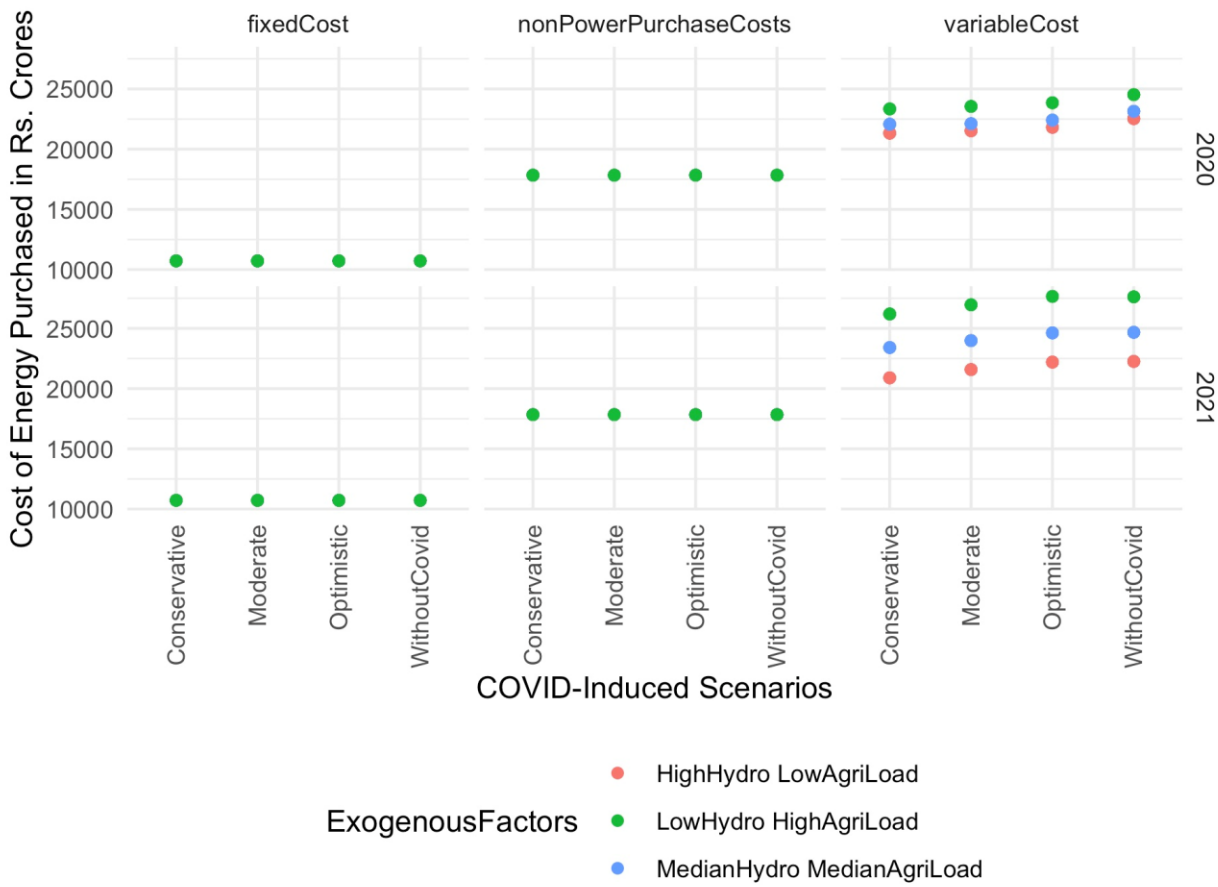

Figure D3: Cost components of total expenditure to discoms

E: Validation

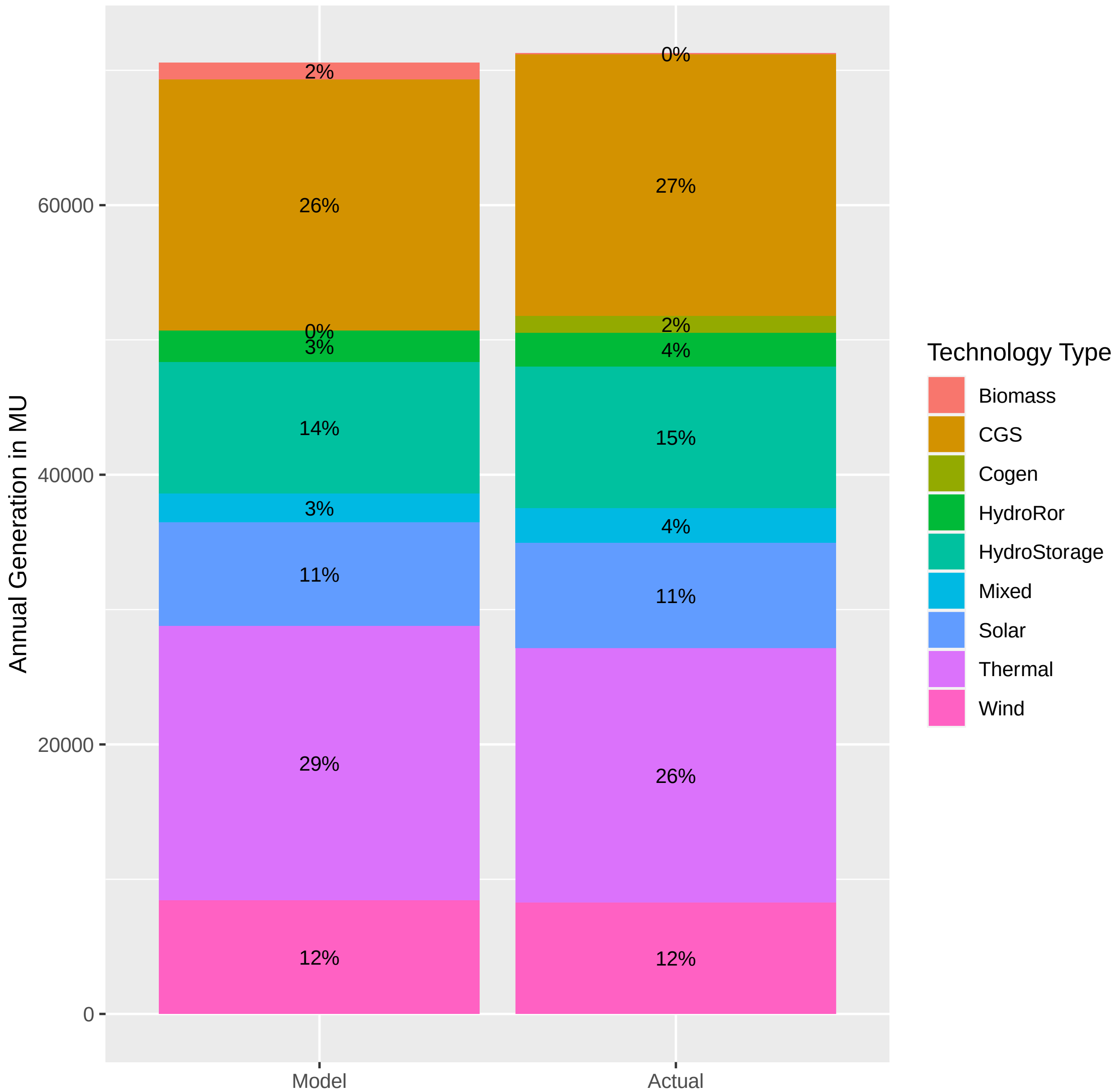

Figure E1: Comparison of model-based and actual generation in FY 19 by technology. Generation is indicated in MWh. (CGS or Central Generating Stations are treated as one unit for this illustration)

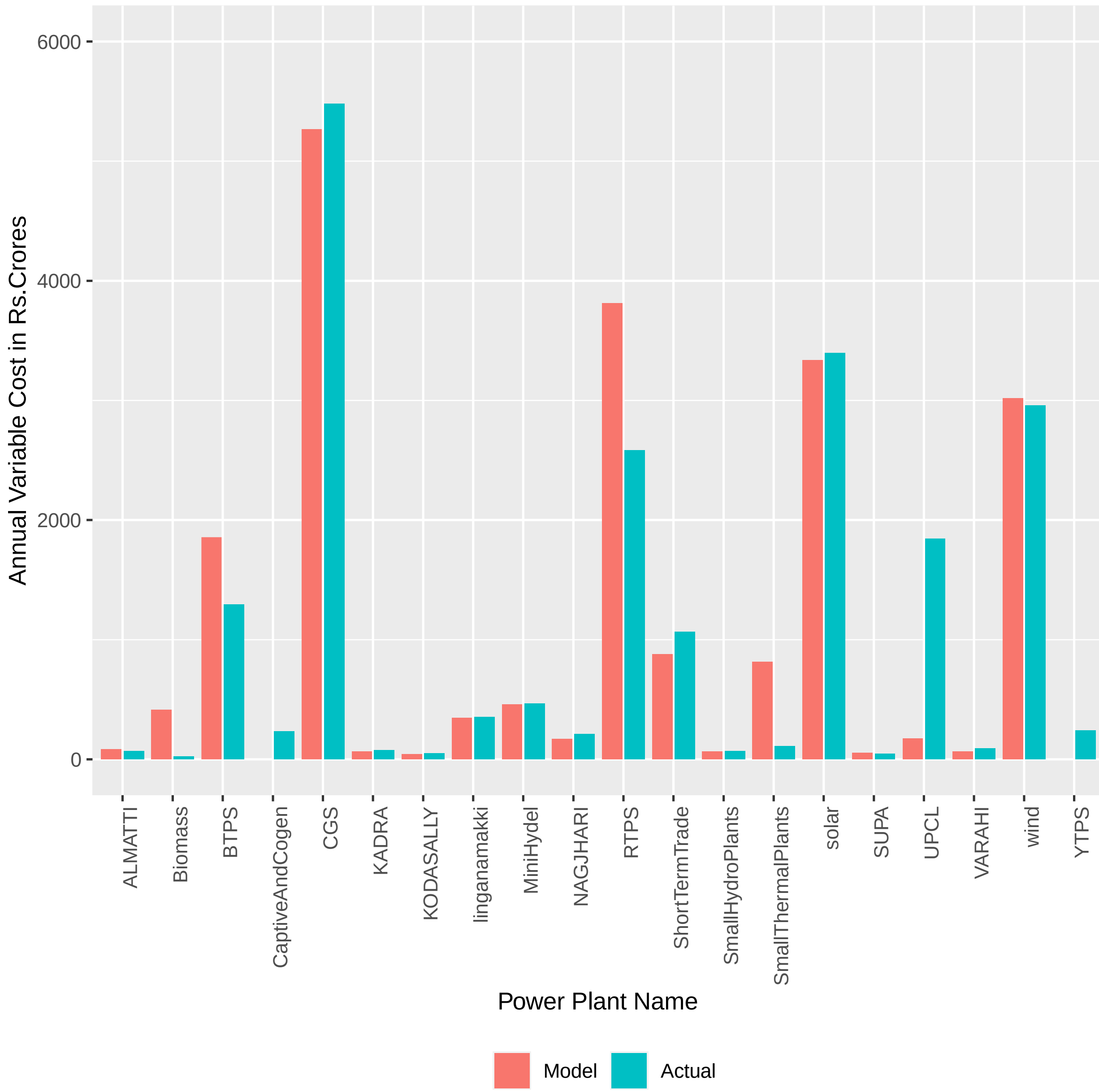

Figure E2: Comparison of model-based and actual cost in FY 19 by plant (Central generating stations or CGS generation are grouped together, as actual generation was available only in the aggregated form for CGS)

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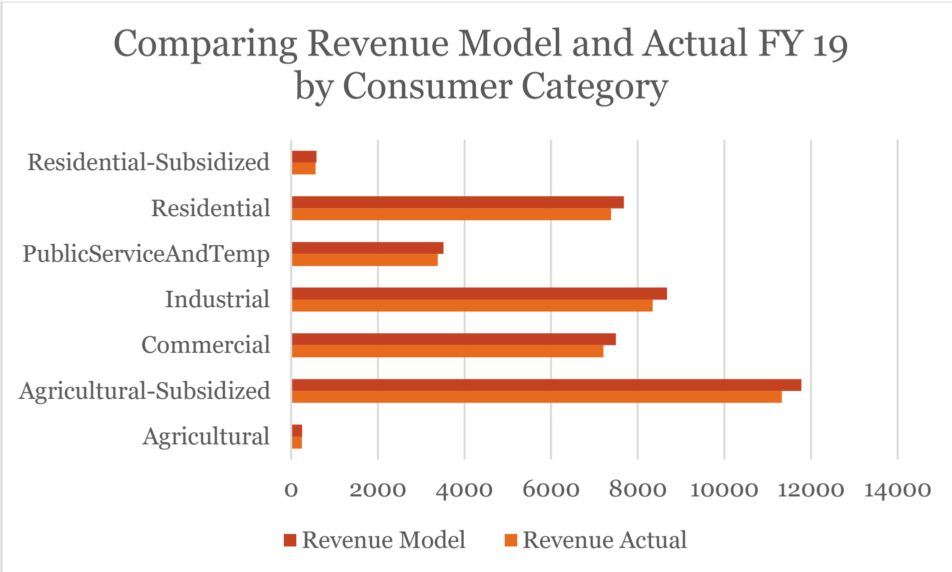

Figure E3: Comparison of model-based and actual revenue by consumer category in FY 19 by plant

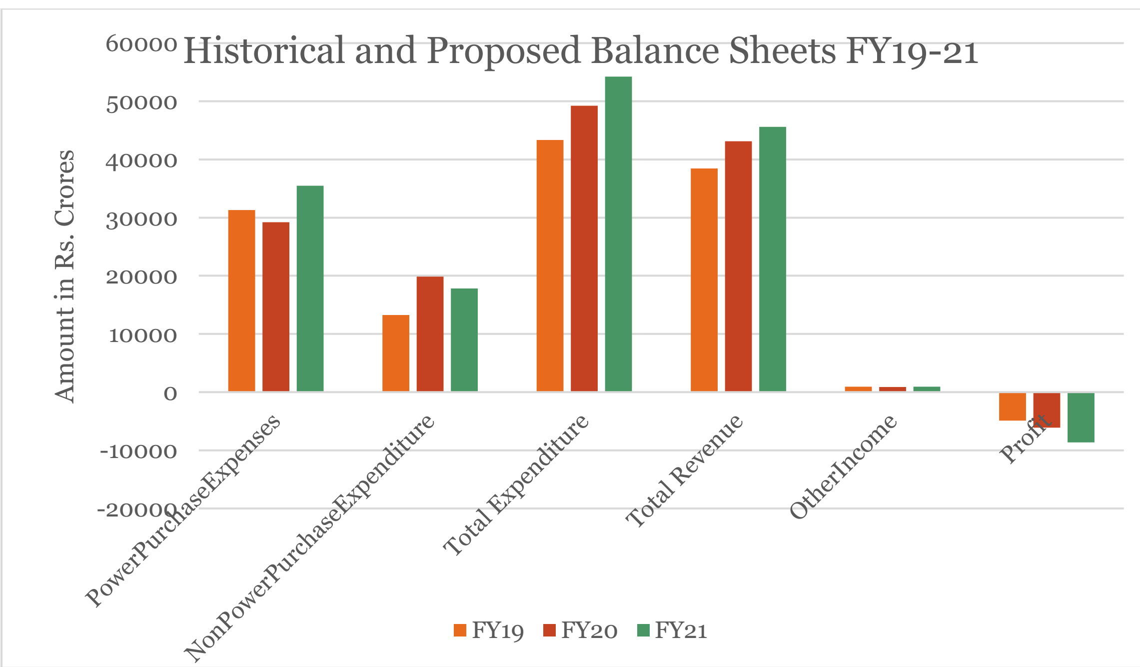

Figure E4: Historical and proposed costs and revenues according to tariff filings.

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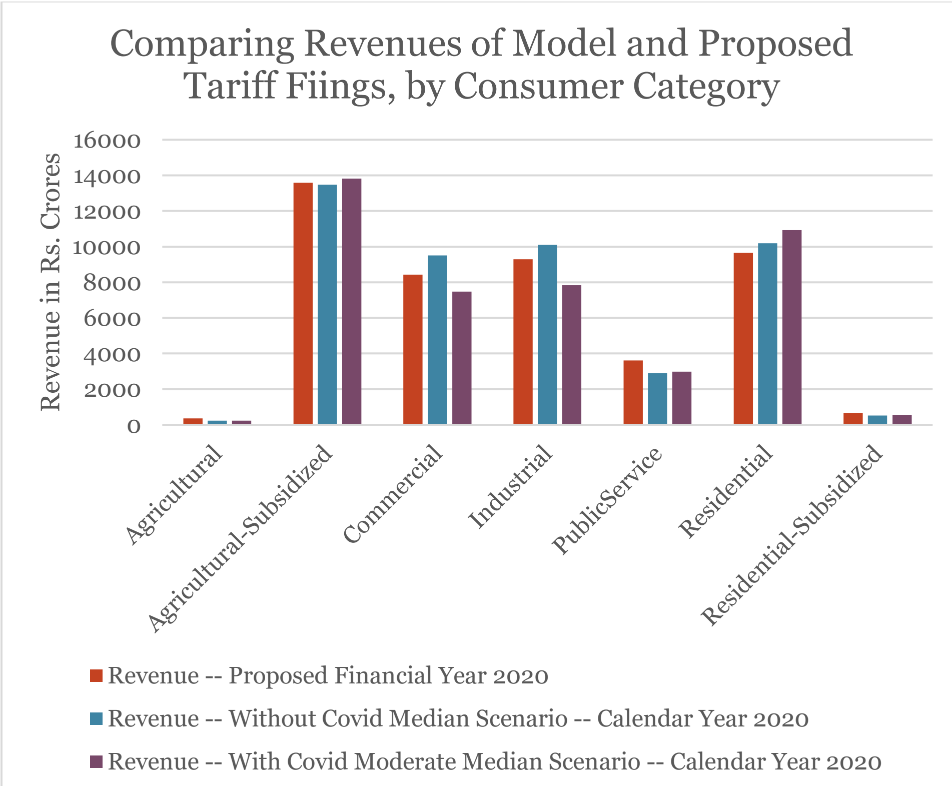

Figure E5: Comparing revenues by consumer category of model 2020 and proposed tariff filings FY21

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F: Additional Analysis and Validation by Discom

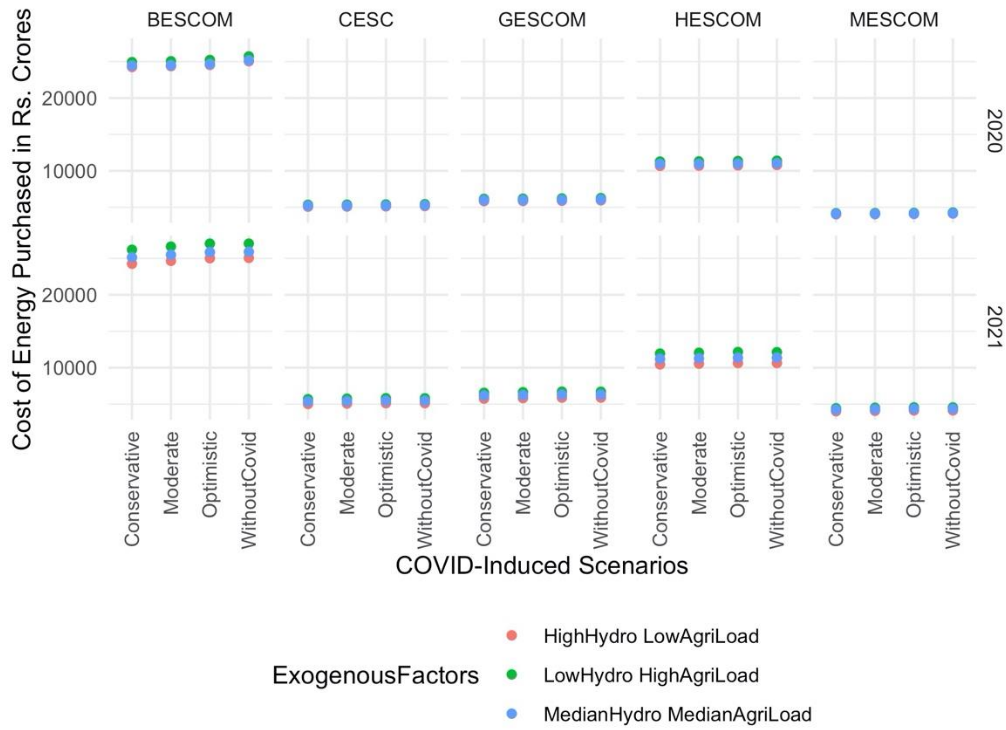

Figure F1: Cost of supply to each discom under various scenarios.

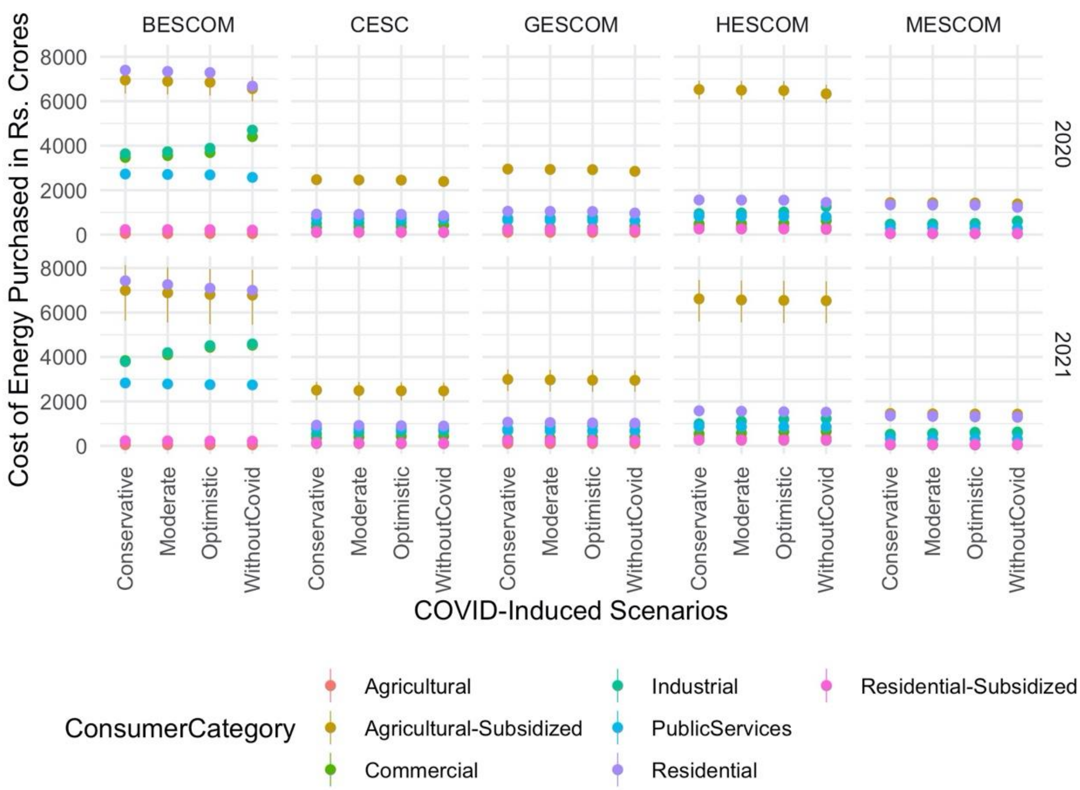

Figure F2: Cost of energy purchased by discom and consumer category. The lines accompanying the points represent the range of results due to exogenous factors such as hydro supply and agri load.

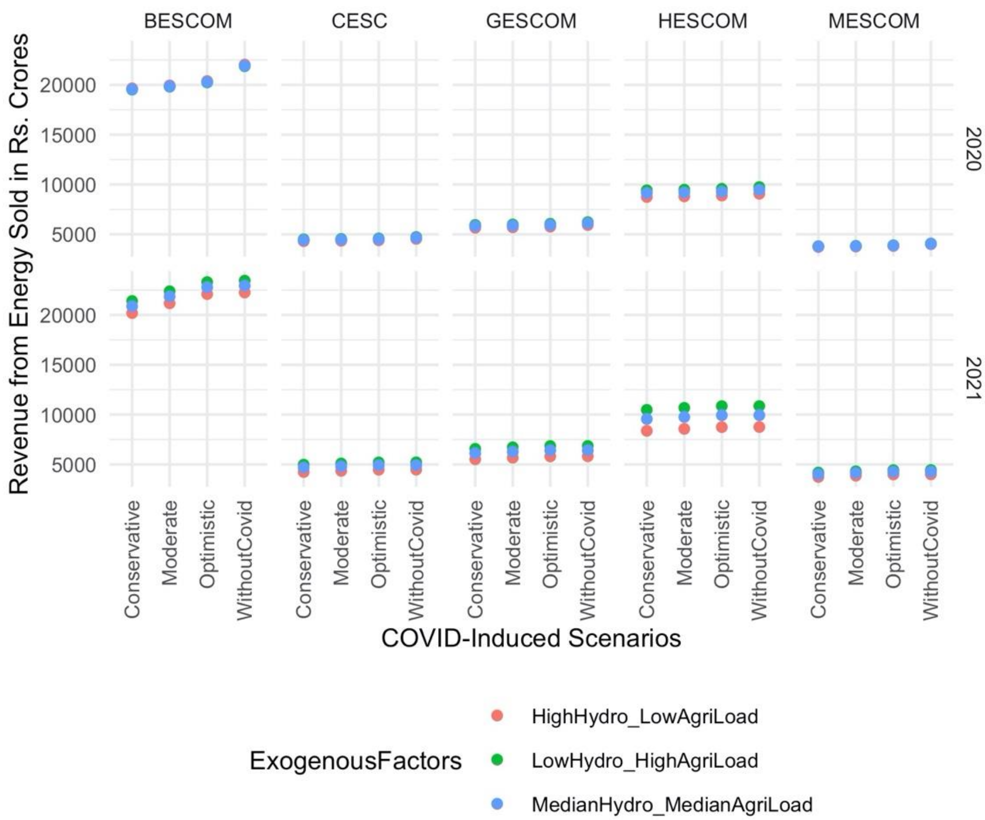

Figure F3: Revenue from energy sold to each discom under various scenarios.

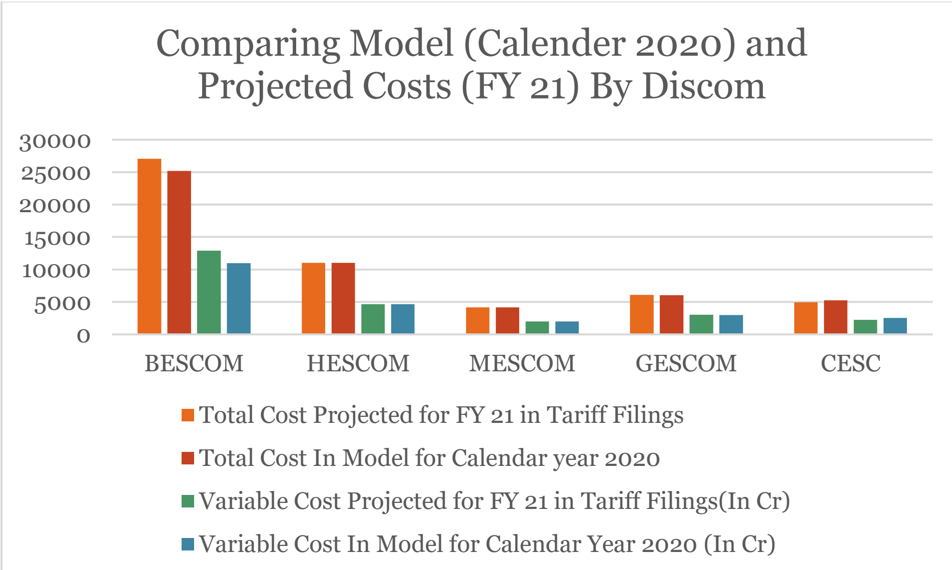

Figure F4: Comparison of costs, project and model-based, by discom (scenario: without COVID-19, median exogenous factors).

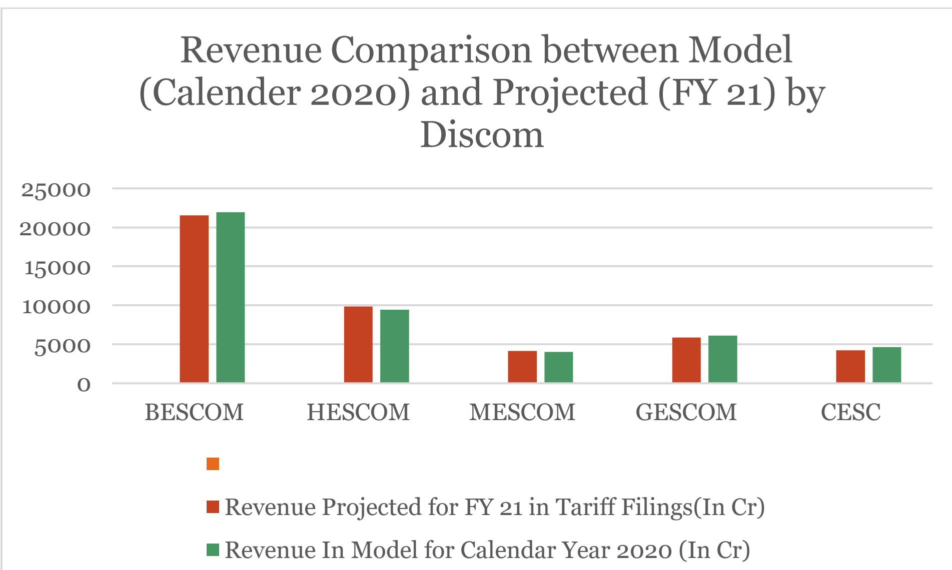

Figure F5: Comparison of revenues, project and model-based, by discom (model scenario: without COVID-19, median exogenous factors).

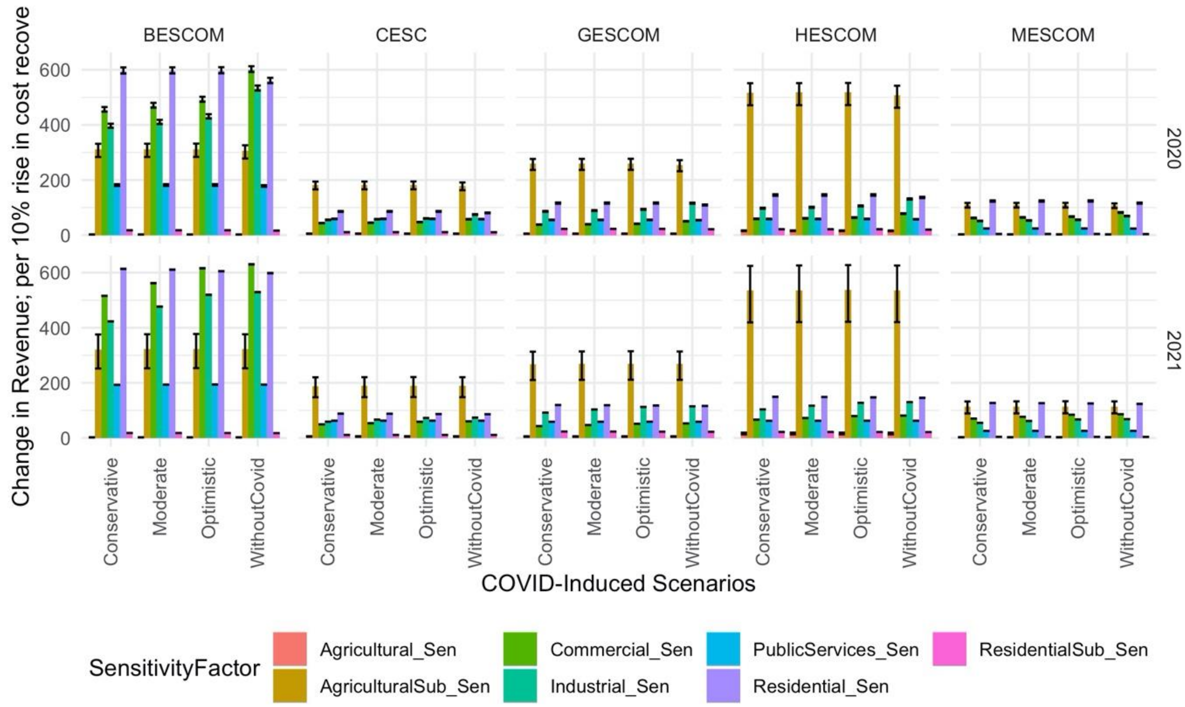

Figure F6: Change in revenue represented in Rs. Crores. Error bars represent variations due to exogenous factors of agri load and hydro supply.

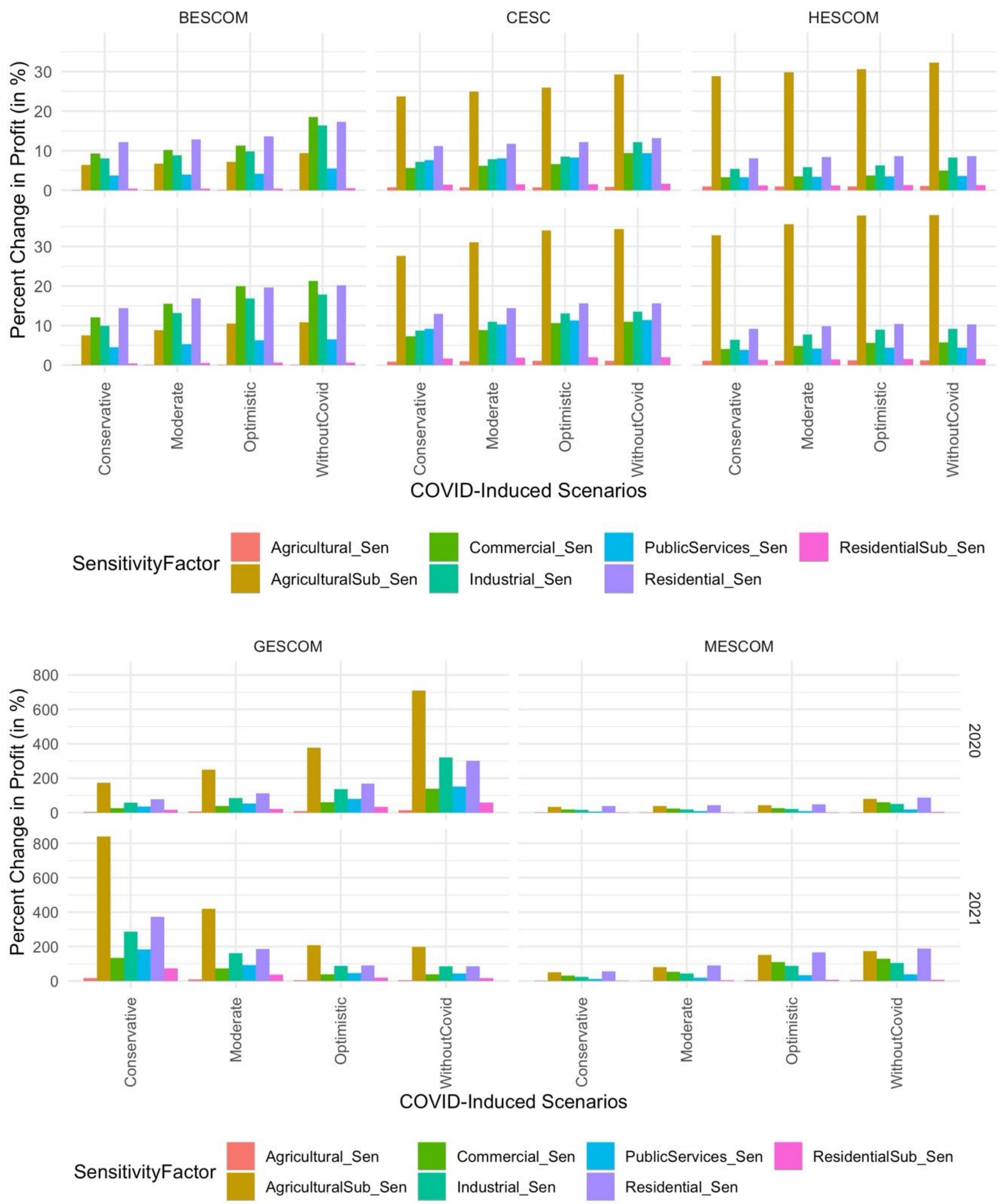

Figure F7: Changes in profit represented in Rs. Crores. Error bars represent variations due to exogenous factors of agri load and hydro supply. Only the intermediate exogenous conditions are shown.