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Using agricultural demand for reducing costs of renewable energy integration

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While demand response is recognized as a useful tool for integrating renewable electricity, the related literature in developing countries has been limited due to lack of data on end-use load profiles. Meanwhile, even though the water-energy-nexus in developing countries is well researched, the value of agricultural pumping load as a demand-side resource to the power system has been ignored. This article fills the gap by collecting agricultural load data from two distribution utilities in the Indian state of Gujarat and using it in a mixed-integer linear programming model to estimate the flexibility provided by agricultural load control to the power system. Using a flexible load representation, the model chooses the optimal periods for agricultural supply subject to the constraints of meeting the irrigation needs of farmers, given the marginal cost of electricity. The model estimates that agricultural load control already reduces total system costs by 5% or USD 6.26 per MWh of agricultural consumption in the current power system. Going forward, with high shares of solar generation, shifting agricultural demand to daytime hours aids system flexibility. It reduces renewables curtailment by 4–7%; limits cycling costs of coal power plants; and reduces marginal integration costs by 21%. Deploying decentralized solar irrigation pumps instead of large-scale solar power plants enables higher absorption of peak solar generation and reduces costs further. Since these costs are disproportionately borne by end consumers, improving system flexibility also improves consumer welfare.

1. Introduction

Demand side management, or electric utility activities designed to influence consumption of electricity to produce desired changes in the load profile [1], can play a key role in integrating large amounts of intermittent electricity [2–5]. Within the demand response literature, relatively little research has explored the value of direct load control to large power systems, despite it being widespread and showing great potential for renewable energy integration [6]. For example, in a regulated power system like India, direct load control by utilities can allow flexible load dispatch to be centrally optimized, accounting for generation from wind and solar plants, inflexible load, and power transmission and distribution constraints. It is anticipated that load control can provide the flexibility required to integrate higher shares of renewable energy [7]. However, a key barrier to understanding the potential of demand side management in developing countries is that many studies do not utilize real-world load control data, limiting their ability to draw conclusions about the impacts of demand side measures. Studies assume demand response potential as a percentage of peak demand, without accounting for actual consumption patterns for different end uses. Additionally, no estimates are available on the impact of demand side measures at the state or national level [8]. This paper addresses this gap by using new, state-level data for agricultural load from two electricity utilities in western Indian state of Gujarat.

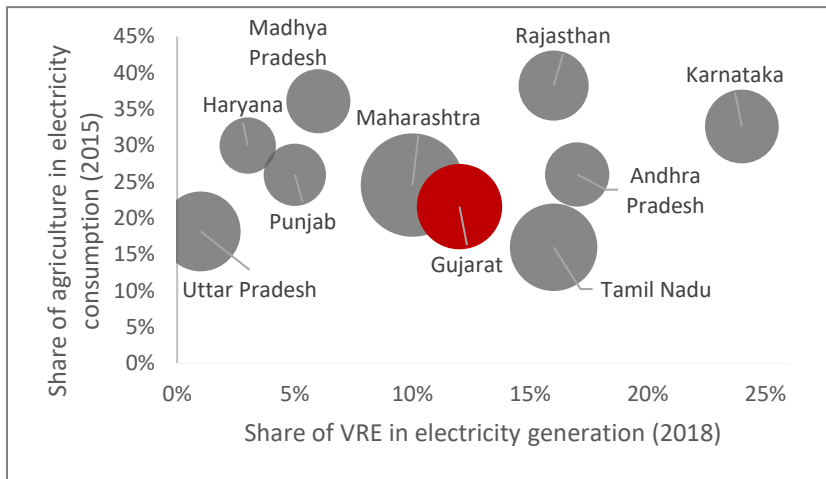
Using this data, this paper quantifies the value of agricultural pumping load in demand side management in the Indian power system, and in doing so this paper adds a new perspective to the literature on the water-energy nexus [9–13]. Agricultural consumption is a major source of electricity demand in developing countries. For example, in Bangladesh, the irrigation season increases the peak electricity demand by almost a quarter; in Iran, groundwater pumping constitutes 11% of total electricity consumption [14]; and in the north China plain, annual energy consumption for groundwater pumping was 13.67 TWh [15]. Similarly, in India, electricity demand for irrigation makes up about 20% of the total consumption [16]. Electricity supply for agricultural pumping is also heavily subsidized across the country. In many states, it is entirely free. To limit the subsidies and prevent their abuse, the supply is controlled by the state-owned electricity utilities. Most farmers receive electricity for only a maximum of 8 hours in a day. This is enabled by a unique system that separates the power distribution network for irrigation and other uses in rural areas (feeder segregation), thereby allowing uninterrupted supply to non-agricultural consumers as well as complete control over agricultural supply. But agricultural pumping load managed through this system is also a valuable demand resource that can be exploited to reduce the cost of integrating high shares of renewables.

The increasing cost of integrating generation from intermittent wind and solar generation is a major challenge facing the Indian power sector [17]. This challenge is not uniformly distributed as only a few renewable resource rich states are leading the energy transition. At the national level, the share of renewables in total electricity generation was 8% in 2018-19, but in the states of Karnataka, Tamil Nadu, Rajasthan, Andhra Pradesh, Gujarat, and Telangana, renewable generation was higher [18]. Agricultural pumping also constitutes between 15–40% of total electricity consumption in these states (Figure 1).

This paper focuses on the western state of Gujarat, which accounts for 10% of India's electricity demand and 14% of her carbon emissions [19,20]. In 2018-19, the total electricity consumption of the state was 120 TWh. As is typical of many Indian states, this demand was met through a predominantly coal-based system, which constitutes about 80% of generation. Wind and solar accounted for 13% of the overall electricity generation in 2018-19 [19]. The ratio of solar to wind in RE generation was 1:4. The share of renewables in Gujarat is expected to increase to 40–50% by 2030 along with an increasing deployment of solar plants [21]. At the same time, agricultural consumption represents around 20% of the total demand

and has been growing by 5–7% annually [22]. Gujarat therefore makes for a good case study as it both a frontrunner in RE development and has an extensive network of agricultural supply with 100% feeder segregation [21]. Additionally, the state is also pioneering the use of solar agricultural pumps. Importantly, the electricity utilities in Gujarat publish their agricultural supply schedules weekly on their website, which allows for collecting data on the hourly agricultural supply.

Figure 1: Share of agriculture in electricity consumption vs. share of RE in electricity generation in large Indian states. Size of the bubble represents total electricity consumption in 2015.



Source: Tariff orders, Central Electricity Authority (CEA)

Using the data from Gujarat this analysis estimates that the current agricultural load management practices reduce total system costs by up to 5% or USD 6.26 per MWh of agricultural consumption in today’s coal-dominated system. Going forward, with high shares of solar generation, shifting agricultural demand to daytime hours substantially aids system flexibility. It reduces RE curtailment, limits cycling costs of thermal power plants, and reduces overall integration costs.

2. Data, modeling methods and scenarios

This analysis uses a mixed-integer linear programming model for optimizing short-term production cost of Gujarat’s power system. Demand response from agricultural pumping load is represented as a flexible load in the model that can be shifted to minimize total system costs, given the demand from other sources and renewables generation. Details of the model and the data used are presented in this section.

2.1. Agricultural load

The lack of data on final consumption profiles in India is a major limitation while evaluating demand response options. Previous analyses have used representative end use profiles available from the study of a handful of electric feeders, yet even these are not available in the public domain [8]. This article uses data published by the distribution utilities Paschim Gujarat Vij Company Ltd (PGVCL) and Uttar Gujarat Vij Company Ltd (UGVCL), which together constitute 90% of the total agricultural demand in Gujarat [22,23] to construct the agricultural supply profile for the state. These are supply profiles and not demand profiles, as they do not represent the unconstrained electricity demand of agricultural consumers. This is because electricity supply to agriculture in Gujarat, as in much of India, is limited to 8 hours a day. The agricultural consumers of UGVCL and PGVCL are divided into 123 groups and power is rotated between

these groups throughout the day to ensure that all consumers receive an uninterrupted supply of 8 hours every day.

Figure 2: Month-wise average hourly supply to agricultural consumers in Gujarat (PGVCL and UGVCL)

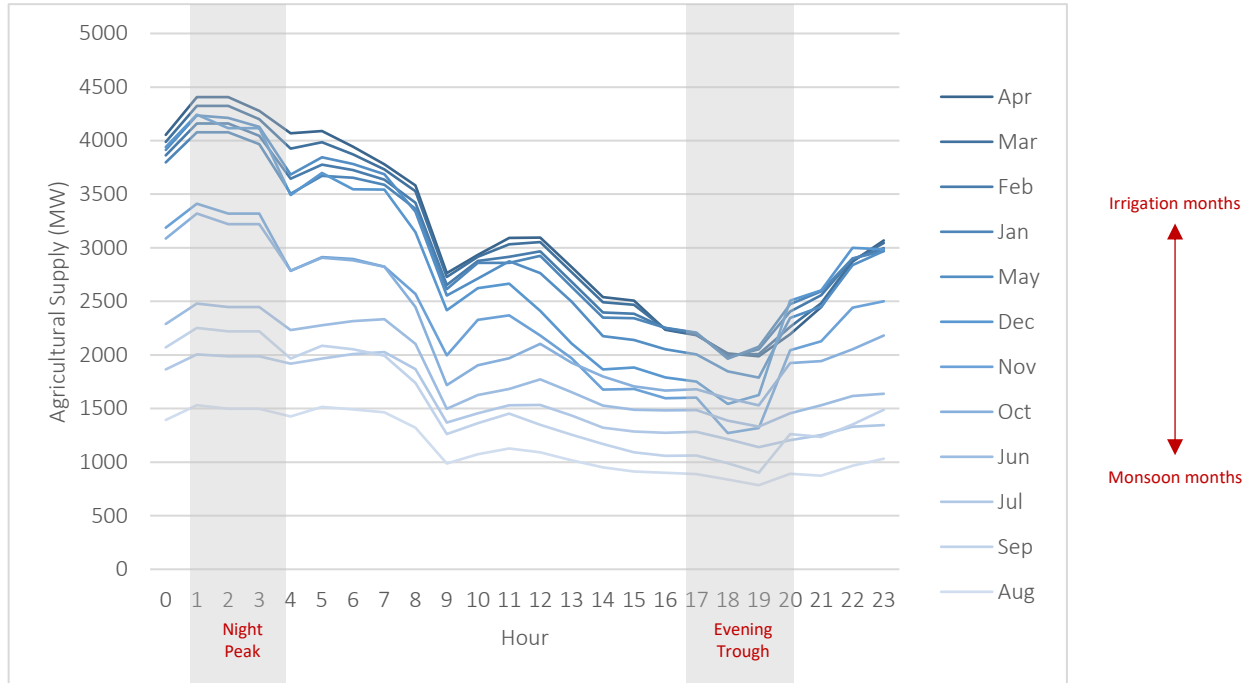
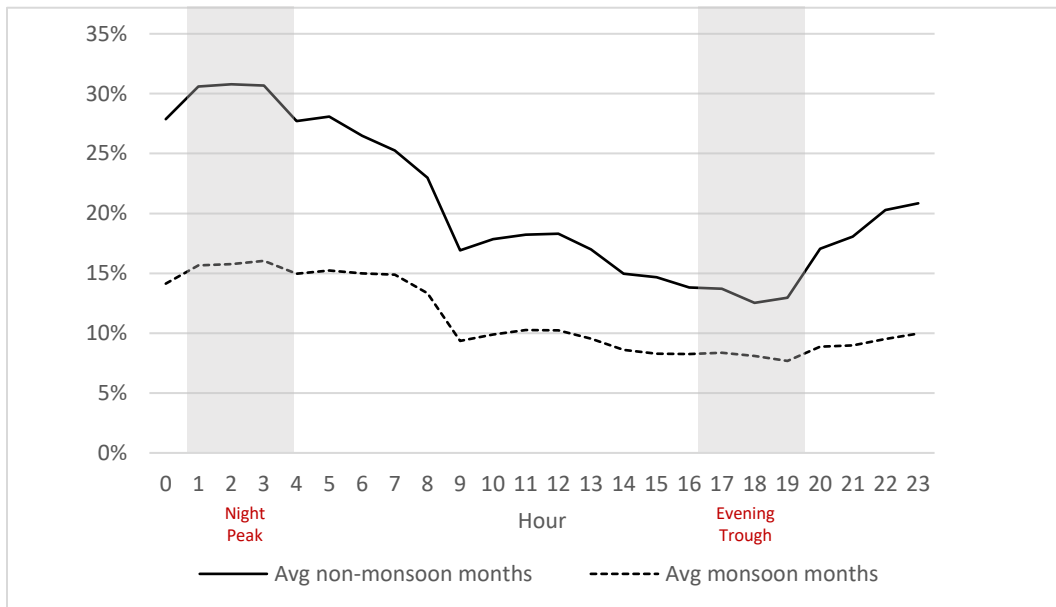


Figure 3: Average agricultural supply (PGVCL and UGVCL) as a percentage of total Gujarat demand



Every week the utilities publish the quantum of power to be supplied to each group and the time during which power will be supplied on their websites [24,25]. But the utilities do not archive this information on their websites. This information was scraped from the websites of the utilities from November 2019 to

October 2020. This enabled creation of the hourly power supply profile for each agricultural group over the 24 hours of the day. Aggregating the power supply across groups (64 for PGVCL and 59 for UGVCL) gives the power supply profile for each utility and the state (Figure 2). Examples of the scrapped schedules are show in Figure A.1 and Figure A.2. The scrapped schedules and the profiles created from them are available on the Github page of this project.

The estimated agricultural supply profiles are substantiated by other available information. First, the curves have the expected shape: power to agricultural consumers as a group is supplied mostly at night when the demand from other consumers is low. Only a minimal amount of power is supplied to agricultural consumers during evening peak load hours (Figure 3). This is in line with our understanding of the power management practices of the utilities. Second, considering technical and non-technical distribution losses of 19.5% for the PGVCL [22] and 9.7% for UGVCL [23], our agricultural supply profiles imply total agricultural sales of around 18,000 GWh. This is close to the approved agricultural sales of 18,700 GWh [22,23]. The difference of 4.3% is reasonable considering the uncertainty in actual distribution losses in the agriculture sector in Gujarat.

The estimated agricultural supply curves show the sizable scale of demand management by Gujarat utilities. Agricultural supply is only 13% of overall demand during peak hours in non-monsoon months but increases to 35% during off-peak at night (Figure 3). The pattern holds in monsoon months, although is less pronounced due to lower agricultural demand. Additionally, the peak power supplied to agricultural consumers is around 4500 MW, against a total connected load of approximately 11500 MW (Figure 2). This implies that the utilities supply power to only about a third of the consumers even during the peak supply hours. From a power system management perspective, this has the combined benefit of minimizing the contribution of agricultural pumping to peak demand and of supplementing the load overnight (leading to reduction of ramping and cycling of thermal units).

2.2. Production cost model in PLEXOS®

This paper uses a unit commitment production cost model built for the state of Gujarat in the PLEXOS® Integrated Energy Model, a commercial energy market modelling tool provided under an academic license by Energy Exemplar [26]. The PLEXOS® engine has four separate phases that can be run separately or in combination: long term (LT), projected adequacy of system assessment (PASA), medium term (MT) and short term (ST). Each phase has a separate function and if run in combination, the higher-level phases pass results to the lower phases. Each step is optimized as a whole, taking the starting condition from the previous step and with no ‘awareness’ of the coming step.

The unit commitment-economic dispatch problem based on the ST phase is a combination of unit commitment, where the set of generators operating (committed) in any given time interval is determined, and economic dispatch, where the lowest-cost configuration of power output levels is determined in each period for committed generators. This combination of binary and linear decisions is solved using a mixed-integer linear programming (MILP) model. The objective is to minimize operating costs of the power system subject to the condition that hourly demand must be equal to supply. Mathematically this is equal to

$$\min\{\sum_{t=1}^n\{\sum_{i=1}^N v_{i,t}c_i(p_{i,t})\}\}, v_{i,t} \in \{0,1\} \text{ subject to } \sum_{i=1}^N p_{i,t} = d_t \quad (1)$$

where, t is the index of time periods in an optimisation step,

i is the index of generators,

N is the total number of generators,

n is the number of time intervals in an optimization step,

$v_{i,t}$ is the binary variable indicating whether a generator is committed (1) or not (0) in each period,

c_i is the operating cost of generator i , and

$p_{i,t}$ is the power output of generator i (MW) in each period.

Further constraints are imposed to account for operational characteristics, including minimum and maximum stable operating levels for each generator, ramp rates etc. The demand profiles, input data for each generator in the model, and the renewable energy profiles used in the model are provided on [GitHub](#). Other key features of the modelling are hourly economic dispatch over a 1-year period with a 1-day planning horizon and an additional 1-day look-ahead at 8-hourly resolution, which is imposed in the PLEXOS environment.

2.3. Modeling agricultural load optimization

The modeling approach for agricultural load follows the flexible load representation by [27]. The overall demand is split into flexible agricultural pumping load and the remaining load that is deemed inflexible. Agricultural load is modelled using the PLEXOS® ‘purchaser class’ that allows a specified quantity of load to be scheduled into the system. The flexibility in scheduling agricultural load is limited by the need to supply a minimum amount of electricity each day to meet irrigation demand, the rated capacity of the agricultural pumps, and the capacity of the distribution system in rural areas. This is mathematically equal to

$$d_t = d_t^I + \sum_{j=1}^J d_{j,t}^F \quad (2)$$

constrained by

$$d_{j,t}^F \leq P_{j,t}^F \quad \text{and} \quad (3)$$

$$\sum_t^{T_u} d_{j,t}^F = E_{j,u}^F \quad (4)$$

where,

d_t is the system demand (MW) in each period,

j is the index of flexible demands,

t is the index of time periods,

u is the index of days,

T_u is the set of time periods in day u

J is the total number of flexible demands,

d_t^I the level of inflexible demand in period t ,

$d_{j,t}^F$ the level of flexible demand dispatched for end use object j in period t ,

$P_{j,t}^F$ is the maximum instantaneous level of flexible demand for end use object j in period t , and

$E_{j,u}^F$ is the required energy of flexible demand for end use object j on day u .

In the current supply scenario, the level for flexible demand ($d_{j,t}^F$) in each discom is taken equal to the actual power supplied to agricultural consumers in that hour as derived in section 2.1. In the optimized supply scenario (see 3.2), the level of flexible demand ($d_{j,t}^F$) in each discom in equation (3) is considered less than or equal to the maximum supply to agriculture in the current system (i.e., $P_{PGVCL,t}^F = 2500$ MW and $P_{UGVCL,t}^F = 2000$ MW). Additionally, the daily required energy of flexible demand ($E_{j,u}^F$) in equation (4) is taken equal to the daily energy supplied to agricultural consumers in a particular day (a day in PLEXOS® is from 00:00 hours to 23:59 hours) as per the supply profiles derived in section 2.1. Taken together, these constraints allow the model to optimize costs by varying agricultural supply during the day while complying to the constraints in peak supply on account of distribution system capacity and seasonal variations in irrigation demand. To preserve computational tractability, the restriction of 8-hour continuous supply is not applied in the optimized scenario. In the scenario with solarization of agricultural pumps under gross-metering (see 3.4), the maximum instantaneous level of flexible demand is assumed to be equal to the installed capacity of the solar pumps (i.e., $P_{PGVCL,t}^F = 9000$ MW and $P_{UGVCL,t}^F = 8500$ MW) times the generation profile of solar power plants. This ensures that agricultural pumps in the model cannot consume more power than is being generated by the corresponding solar panel output.

2.4. Other model inputs

In the Indian power sector, the merit order dispatch of power plants is based on contracted generation capacity. To enable an accurate representation of the power available to the state of Gujarat, our production cost model maps all the (in state and out of state) power plants which have a power purchase agreement with Gujarat to the extent their capacity is contracted by Gujarat.

The model uses hourly load for the state of Gujarat for 2018-19 [29] for modeling the aggregate demand in the model. The load was disaggregated to different distribution companies using historical power requirement data from the Gujarat Electricity Regulatory Commission's (GERC) tariff orders. Hourly agricultural load was deducted from the overall load to calculate the hourly inflexible load in the system.

The MW capacity for each conventional power plant is considered as per tariff orders of the GERC [22]. The fixed cost (including investment cost, O&M, and depreciation) and variable cost (fuel cost) are taken as approved by GERC tariff orders [22]. Operational parameters for the thermal power plants are based on generic data from Central Electricity Authority. Deterioration in parameters due to lower capacity factors is not considered. For renewable energy, the actual installed capacity for 2018-19 is considered for the baseline scenario. This is increased for scenarios with higher RE share. The generation profile of RE power plants is based on the month-wise average hourly generation profiles for 2018-19 published by Gujarat State Load Dispatch Center (SLDC) [30]. Since have a single-part tariff in India, the variable cost is taken equal to zero for production cost modeling and equal to USD 40/MWh for cost calculations.

All the input data for power plants, load (flexible and inflexible), and renewable energy profiles is available on the Github page of the project.

3. Results and discussion

3.1. Impact of an increasing share of RE

Gujarat's power system was modeled under varying RE scenarios. In the baseline scenario, the overall energy demand, generation capacity, RE share (13%), and the supply to agriculture were taken equal to the actual values in 2018-19. Since Gujarat does not plan to build any new coal power plants, the share of RE in the overall energy mix is expected to rise in the future. To assess the impact of increasing share of RE, the amount of RE in the system is increased to 20%, 30% and 50% of the total generation. This is in line with the plans laid out by the state government for development of renewables [21]. To account for the uncertainty in share of wind and solar within the overall RE generation, three sub-scenarios were also modeled: high wind (ratio of solar to wind generation = 1:4 as was the case in 2018-19), high solar (ratio of solar to wind generation = 2:1), and equal wind-solar (ratio of solar to wind generation = 1:1).

At higher renewable shares, the operation of coal power plants changes. The weighted average capacity factor of coal power plants declines from 73% in the current system to 45% in a system with 50% RE. Further, as the RE penetration increases, the variation in average capacity factor of the coal fleet increases (Figure 4). The varying generation from wind and solar plants also leads to frequent cycling of coal power plants. Ramping requirements of coal power plants increase sharply as RE penetration increases to 30%, while the number of unit-starts required increases more sharply as the RE share rises to 50%. Further, the system is unable to absorb RE at certain times leading to curtailment. Such curtailment is highest during the months of Dec-Feb and May-Jun, when solar generation is high and net load is low. Total curtailment increases sharply as RE share increases to about 50% and is estimated at 10.1% for solar and 6.9% for wind. It should be noted that this is the scheduled curtailment on account of imbalance between demand and supply and does not include curtailment due to forecast errors in RE generation and local grid congestion.

3.2. Value of agricultural load control to Gujarat's electricity system

To understand the value of agricultural load control, the agricultural demand is first taken to be equal to the current supply, i.e., the supply hours and quantity of power supplied in any hour is taken equal to the curves estimated in section 2.1. Next, the model optimizes the timing and quantum of agricultural demand in any hour to minimize the production costs. This is subject to the constraint that daily energy supplied for irrigation matches the current schedule and that the maximum agricultural load served by a utility at any point is equal to the maximum load currently served to account for the distribution system level grid constraints (see section 2.3 for mathematical formulation).

The model shows that the current supply schedules are highly optimized for the coal-based generation mix. The left panel of Figure 5 shows the average hourly supply of electricity to agriculture consumers in Gujarat, along with the optimized supply chosen by the PLEXOS model in the current capacity mix. We can see that the two curves overlap neatly. The minor differences could be on account of practical limitations in shifting load and providing 8 hours of continuous supply. Disaggregating the supply curves by season, for the monsoon and the non-monsoon period reveals similar trends (Figure A.5).

Figure 4: Thermal power plant metrics and RE curtailment under increasing penetration of renewable energy. These results are derived for RE shares of 20%, 30% and 50% considering 1:1 ratio of solar to wind in RE generation. In the box plots, the points represent individual power plants.

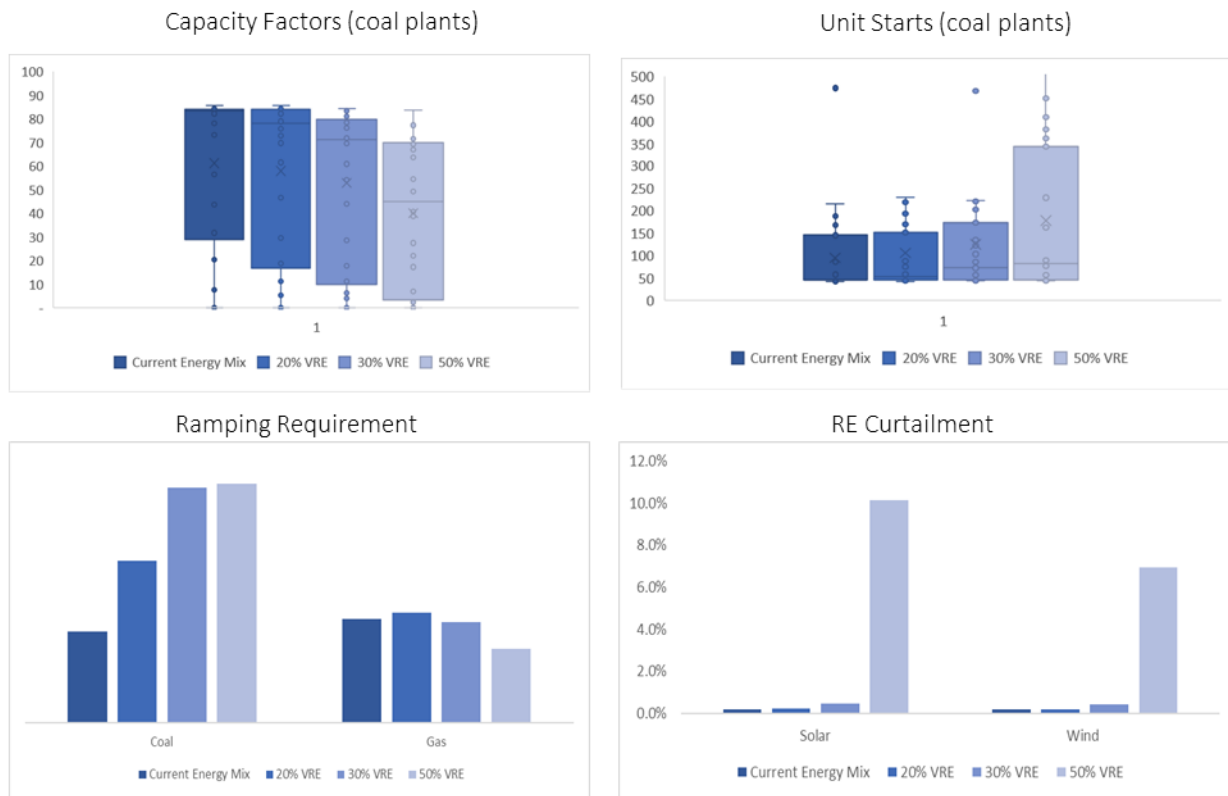
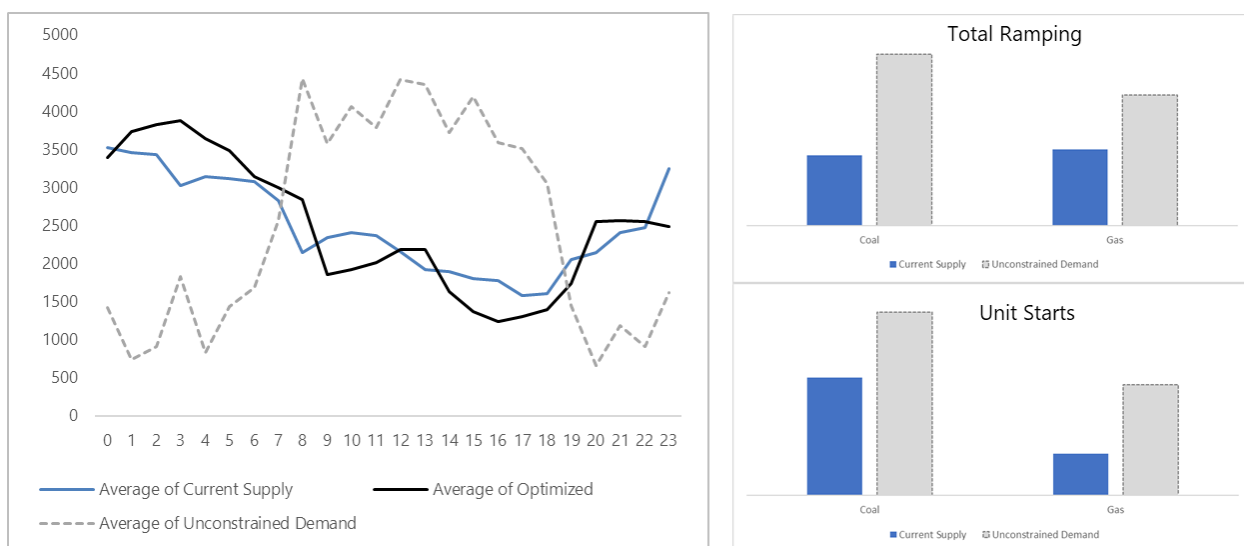


Figure 5: Actual and optimized supply to agriculture and the reduction in unit starts (left panel) and ramping due to direct load control of agriculture (right panel). These results are derived for power plant capacities and share of RE in the current system (2018-19).



To quantify the benefit derived by the Gujarat power system from the direct load control of agriculture, a hypothetical demand curve for agricultural consumers at the state level was created wherein 75% of the consumption occurs during daytime (8–20h) reflecting the long-standing demand of agricultural consumers for daytime supply (unconstrained demand scenario) [31]. The total system cost estimated by the model using the unconstrained demand curve is about 5% higher than the cost for the system calculated using the actual supply curves derived in section 2.1. The reduction in costs is due to lower cycling of thermal power plants and decrease in fuel costs. The right panel of Figure 5 shows the reduction in unit starts and ramping in the current system compared to the unconstrained demand scenario.

Thus, direct load control of electricity supply to agriculture is a system service even though it is not explicitly valued as such. Provision of a similar scale of demand response service through the market mechanism, if it were even possible, would imply an additional cost to the power system. A conservative estimate of this additional cost can be calculated by dividing the reduction in total system cost enabled by agricultural load control, accounting for the reduction in additional unserved energy, by the consumption of agricultural consumers. Using this method, the value of agricultural demand response in the current system is estimated to be USD 6.28 per MWh of agricultural consumption or INR 0.44 per kWh of agricultural consumption. This is substantial when compared to the energy charges of INR 0.60 per unit of consumption for irrigation pumps in 2018 [23].

It is advantageous to shift agricultural supply to daytime hours with increasing share of solar generation.

The current agricultural supply is organized such that most of that power for irrigation is supplied at night to the farmers. While this practice is optimal in a coal dominated system, the model shows this would not always be the case at higher shares of RE (Figure 6). The current supply schedules would continue to be optimal if the increase in share of RE is led by higher deployment of wind rather than solar. In the scenario where the ratio of solar: wind is maintained at the current level (1:4), it is only optimal to shift agricultural load to daytime during the monsoon months of June-September when higher wind generation and low demand during the day allows for daytime supply to farmers. However, if more solar is deployed in the future such that the ratio of solar: wind in the system increases to 1:1 or more, system cost minimization would require shifting more of the agricultural load to daytime hours. This would provide the power system with greater flexibility to absorb peak solar generation between 12 P.M. and 2 P.M. The only constraints are that under the current mechanism of load control, all farmers are guaranteed a fixed amount of supply for 8 hours every day. Additionally, the local distribution system has limited capacity so all the farmers cannot be supplied power at the same time. This implies that agricultural supply cannot be increased to match the peak solar generation such that there is a complete overlap between agricultural load and solar power generation. This might however be achieved by deploying decentralized solar panels for irrigation (see section 3.4).

Agricultural load control lowers integration costs. Shifting agricultural supply to daytime hours reduces ramping requirements and unit starts for coal power plants, providing the higher flexibility that is particularly needed in systems that rely on solar (Figure 7). However, with a more flexible demand, the capacity utilization of coal power plants also declines marginally. At 50% RE share, the weighted average capacity factor increases from 45% to 43%. Additionally, solar curtailment reduces from 10.1% to 2.9% and wind curtailment reduces from 6.9% to 3.1% in the scenario where the share of RE is 50% as the system is better able to absorb peak daytime generation. Agricultural demand management therefore reduces the imbalances in the power system and allows for a more efficient operation of the existing coal power plants, while simultaneously enabling increased absorption of renewable energy in the system.

Figure 6: Actual and optimized supply hours to agriculture in scenarios with high share of renewable energy. Monsoon months include June, July, August, and September. The supply curves are derived for models with 50% RE share. Month-wise supply curves under the same scenarios are given in Figure A.4.

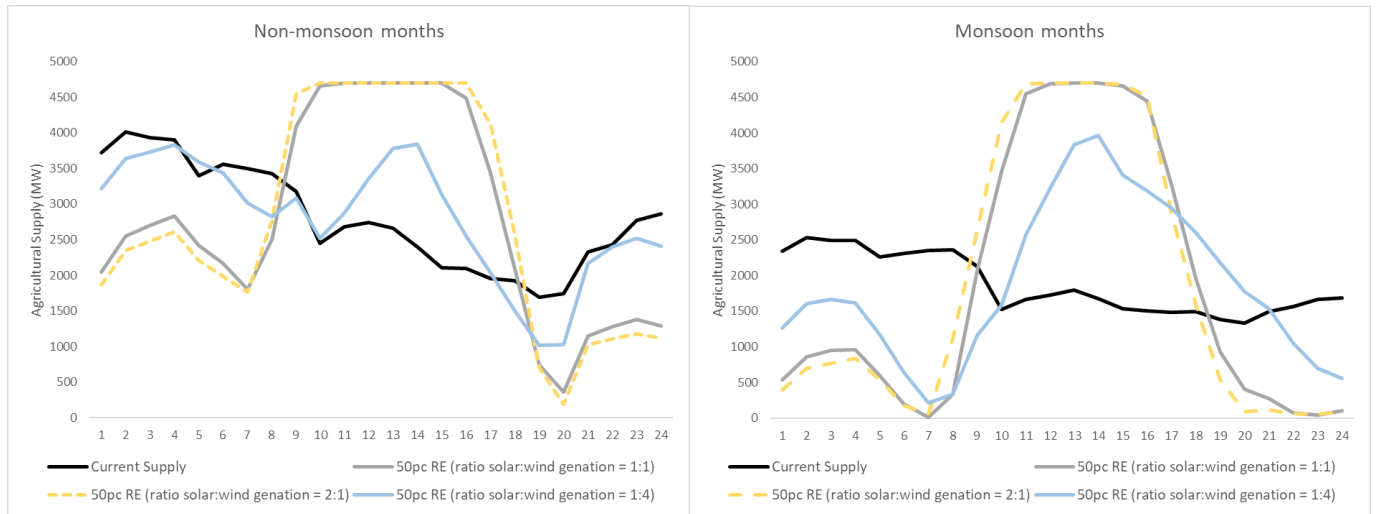
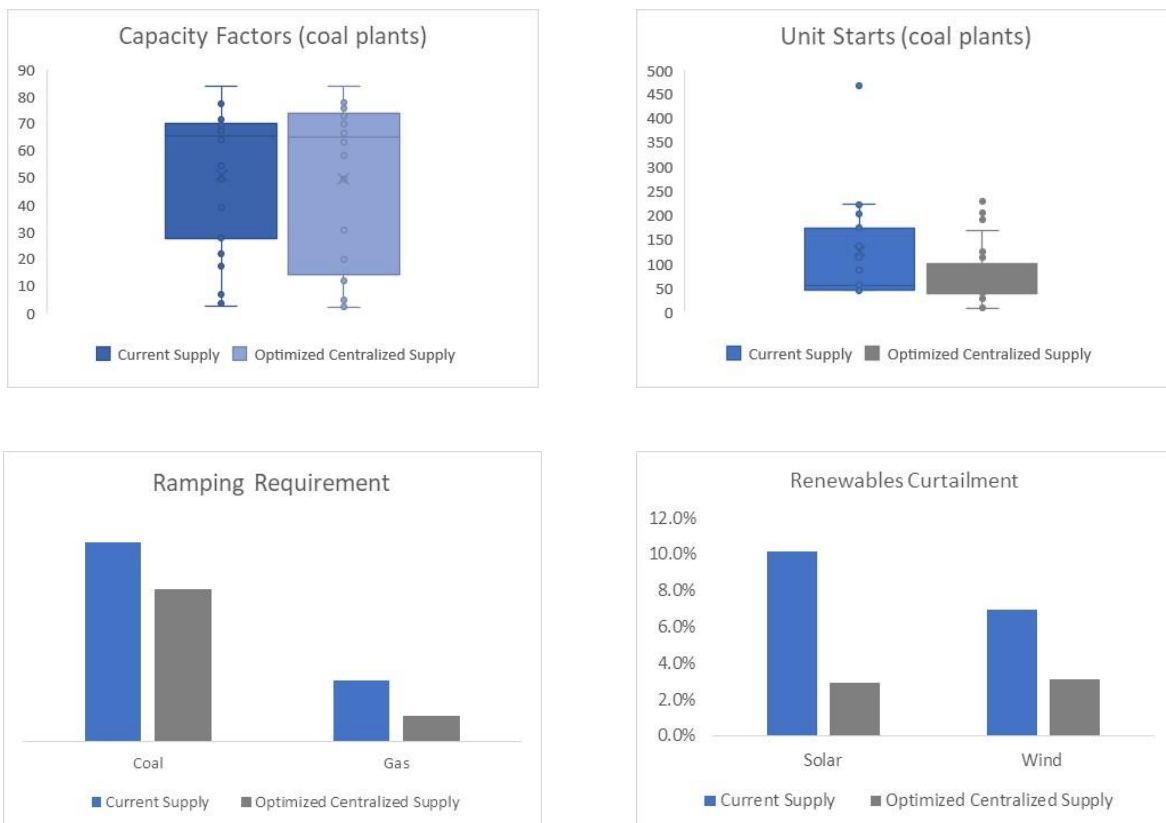


Figure 7: System metrics for current agricultural supply vs. optimized supply. These results are derived for a model with 50% RE share and 1:1 ratio of solar to wind in RE generation. In the box plots, the points represent individual power plants.



3.3. Economic costs of RE integration

Integrating large shares of RE imposes costs on the power system. These can be categorized into the impact of temporal variability or “profile costs”, the impact of uncertainty or “balancing costs”, and the impact of location or “grid-related costs” [32–34]. Of these, profile costs have been shown to be the largest component of integration costs [33]. Profile costs reflect the market value of electricity at different moments in time and the costs of matching RE generation and load profiles. They can further be decomposed into flexibility costs and the utilization effect. Flexibility costs are incurred due to adjustment of the output of thermal plants through higher ramping, starts and shutdowns. Utilization effect is the cost imposed by RE on system due to their generation profile (their availability only during certain times of the day), which leads to lowered utilization of thermal capacity and curtailment of RE during certain hours of the day when the system cannot absorb the excess generation.

This is the first study to provide estimates of RE integration costs in India. Previous studies [8,35] on RE integration in India have focused on capacity credit or adequacy costs. However, adequacy costs only address the low-capacity credit of RE, while the utilization effect is more general: thermal utilization is reduced as the residual load curve becomes steeper and RE utilization is reduced as generation needs to be curtailed [33].

Flexibility costs. Using standard assumptions for cycling costs [36], the model estimates flexibility costs for the Gujarat system to be between USD 1–2 per mega-watt hour (MWh). The marginal increase in costs per unit of RE generation is estimated to around USD 2 per mega-watt hour of RE generation (MWh_{RE}) at 50% RE penetration (Utilization effect. Gujarat currently has 19 GW of thermal power capacity with a total fixed cost payment of USD 1888 mn/annum (INR 13,200 crore/annum). As per long-term PPAs between the distribution utility and thermal power plants, this amount is payable irrespective of the actual utilization of the thermal capacity. The average thermal capacity utilization decreases from 64% in the current system to 38% with 50% RE generation. Increasing the RE share from its current level to 50% increases fixed cost from USD 18 per mega-watt hour of thermal generation ($MWh_{thermal}$) to USD 30/ $MWh_{thermal}$. This corresponds to a marginal increase of USD 18/ MWh_{RE} in thermal capacity costs at 50% RE share and is similar to the estimates from other power systems[33]. Reduced thermal plant utilization is not a transitory phenomenon. Not only does a swift introduction of renewables reduces thermal plant utilization, high RE shares lead to lower average plant utilization even in the long-term equilibrium [33], even though there might be marginal improvement in utilization as some of the unprofitable plants exit the system. This is something that we are not able to capture here. Further, in the scenarios modeled in this paper, it is assumed that the PPAs with thermal power plants will continued to exist even as RE penetration increases. Therefore, optimizing the agricultural supply does not result in decrease in fixed costs of thermal power plants even though optimizing agricultural supply further reduces capacity factor of some coal power plants such that they become redundant in the system. It is reasonable to expect that if there is a surplus of contracted thermal capacity the utility will either renegotiate PPAs or allow at least some let some expire. Optimizing agricultural supply should therefore also further reduce the thermal utilization costs.

Table 1). These estimates are in line with those from other power systems [33]. As expected, the costs increase with the share of RE in the system, though the marginal increase is relatively stable. Optimizing agricultural supply keeps flexibility costs to less than USD 1/MWh even at 50% RE penetration, with a negligible increase in marginal costs. While small, it should be noted that these estimates are for

scheduled ramping and starts, while uncertainty-related cycling is reflected in balancing costs. Further, they do not consider the impact of frequent cycling on efficiency of coal power plants through increase in heat rates.

Utilization effect. Gujarat currently has 19 GW of thermal power capacity with a total fixed cost payment of USD 1888 mn/annum (INR 13,200 crore/annum). As per long-term PPAs between the distribution utility and thermal power plants, this amount is payable irrespective of the actual utilization of the thermal capacity. The average thermal capacity utilization decreases from 64% in the current system to 38% with 50% RE generation. Increasing the RE share from its current level to 50% increases fixed cost from USD 18 per mega-watt hour of thermal generation (MWh_{thermal}) to USD 30/ MWh_{thermal} . This corresponds to a marginal increase of USD 18/ MWh_{RE} in thermal capacity costs at 50% RE share and is similar to the estimates from other power systems[33]. Reduced thermal plant utilization is not a transitory phenomenon. Not only does a swift introduction of renewables reduces thermal plant utilization, high RE shares lead to lower average plant utilization even in the long-term equilibrium [33], even though there might be marginal improvement in utilization as some of the unprofitable plants exit the system. This is something that we are not able to capture here. Further, in the scenarios modeled in this paper, it is assumed that the PPAs with thermal power plants will continued to exist even as RE penetration increases. Therefore, optimizing the agricultural supply does not result in decrease in fixed costs of thermal power plants even though optimizing agricultural supply further reduces capacity factor of some coal power plants such that they become redundant in the system. It is reasonable to expect that if there is a surplus of contracted thermal capacity the utility will either renegotiate PPAs or allow at least some let some expire. Optimizing agricultural supply should therefore also further reduce the thermal utilization costs.

Table 1 Economic (profile) costs of RE integration under various shares of RE, and with and without agricultural demand response. The results for high RE share are derived for a model with 50% RE share and 1:1 ratio of solar to wind in RE generation.

		Without optimized agricultural supply		With optimized centralized agricultural supply	
		Current energy mix (13% RE)	50% RE	Current energy mix (13% RE)	50% RE
Flexibility Costs					
1	Generation (GWh)	1,20,562	1,20,838	1,20,647	1,20,862
2	RE generation (GWh)	14,153	57,335	14,153	60,709
3	Start-up/shut-down charges (\$'000/a)	95,405	1,75,841	81,266	78,922
4	Ramping charges (\$'000/a)	9,131	17,735	5,088	10,587
5	Flexibility costs (\$/MWh)	0.87	1.60	0.72	0.74
6	Increase in flexibility costs per MWh of RE generation (\$/MWh _{RE})	-	2.06	-	0.07
7	Increase in flexibility costs per unit of RE generation (INR/kWh _{RE})	-	0.14	-	0.00
Utilization Effect					
8	Thermal capacity (GW)	19	19	19	19
9	Thermal generation (GWh)	105,605	62,701	105,689	59,351
10	Capacity factor (%)	64%	38%	64%	36%
11	Thermal capacity costs (\$'000/a)	1,887,785	1,887,785	1,887,785	1,887,785

		Without optimized agricultural supply		With optimized centralized agricultural supply	
		Current energy mix (13% RE)	50% RE	Current energy mix (13% RE)	50% RE
12	Levelized thermal capital costs per unit of thermal generation ($\$/MWh_{thermal/a}$)	18	30	18	32
13	RE generation (MWh)	14,153	57,335	14,153	60,709
14	Increase in thermal capital costs (“marginal costs”) per MWh of RE generation ($\$/MWh_{RE}$)	-	18	-	18
15	Increase in thermal capital costs (“marginal costs”) per RE generation (INR/kWh _{RE})	-	1.24	-	1.24
16	RE potential generation (MWh)	14,153	62,541	14,153	62,541
17	RE generation (MWh)	14,153	57,335	14,153	60,709
18	RE curtailment (MWh)	-	5,206	-	1,832
19	RE curtailment (%)		8%		3%
20	VRE capacity cost ($\$'000$) @ avg cost $\$40/MWh$	5,66,128	25,01,651	5,66,128	25,01,651
21	VRE capacity cost ($\$/MWh_{VRE}$)	40	44	40	41
22	Marginal increase in RE capital costs (“marginal costs”) per MWh of RE generation ($\$/MWh_{RE}$)	-	5	-	2
23	Marginal increase in RE capital costs (“marginal costs”) per unit of RE generation (INR/kWh _{RE})	-	0.34	-	0.11
22	System integration costs (6+14+22) ($\$/MWh_{RE}$)		25		19
23	System integration costs (7+15+23) (INR/kWh _{RE})		1.73		1.36

The second component of utilization costs is due to RE curtailment, which increases sharply as RE share reaches around 50%. Consequently, the marginal RE capacity costs rise sharply to USD 5/MWh_{RE}. Note that these costs are due to scheduled curtailment on account of imbalance between demand and supply. It does not account for curtailment due to forecast errors in RE generation and local grid congestion. Optimizing the agricultural supply allows for utilization of the peak time solar and wind generation. This reduces RE curtailment from 8% to 3% and utilization costs by more than half to USD 2/MWh_{RE}. Overall, using agricultural demand response reduces the total marginal costs of RE integration (flexibility costs and the utilization effect) by 21%, from USD 25/MWh_{RE} to USD 19/MWh_{RE}.

Sharing of profile costs. Under perfect and complete electricity markets in long-term equilibrium, profile costs estimated above would appear as reduced revenues from the day-ahead spot market, implying reduced average revenue for all power plants in the short term and permanently reduced revenues for RE plants in the long term [37]. However, 90% of the power in India is traded not on the wholesale market but rather through long-term contracts between distribution companies and generators. Legacy contracts for thermal generators are based on a two-part tariff (fixed cost and variable costs calculated separately on cost plus basis) and contracts for renewable generators consist of single-part tariff (calculated either on cost plus basis or increasingly in RE auctions). The contracting structure in India implies that profile costs are shared in a way that little incentive exists to reduce them. Flexibility costs are typically borne by the generation companies in the contracting structure outlined above. Though thermal power plants can ask to be compensated on account of frequent start-stops and ramping, most of these costs must be absorbed as higher operational expenses. The utilization effect of thermal power plants is borne completely by distribution companies who are required to pay the fixed costs irrespective of the capacity utilization. The second component of profile costs, the utilization effect of RE plants will also add to

power purchase cost of utilities. In most Indian states, RE power plants have a must run status and generators need to be compensated by the distribution company for scheduled curtailment. Often curtailment of RE is claimed by utility on grounds of system security and generators are not compensated. To the extent that investors in RE power plants can anticipate curtailments and price their bids in renewables auctions accordingly, costs are again likely to be borne by the distribution companies. Despite the increased cost, distribution companies have little incentive to remedy the situation. Since power purchase costs are completely recoverable in regulator mandated retail tariffs, any increase in integration costs will therefore directly translate into increase in retail prices and reduction in consumer welfare.

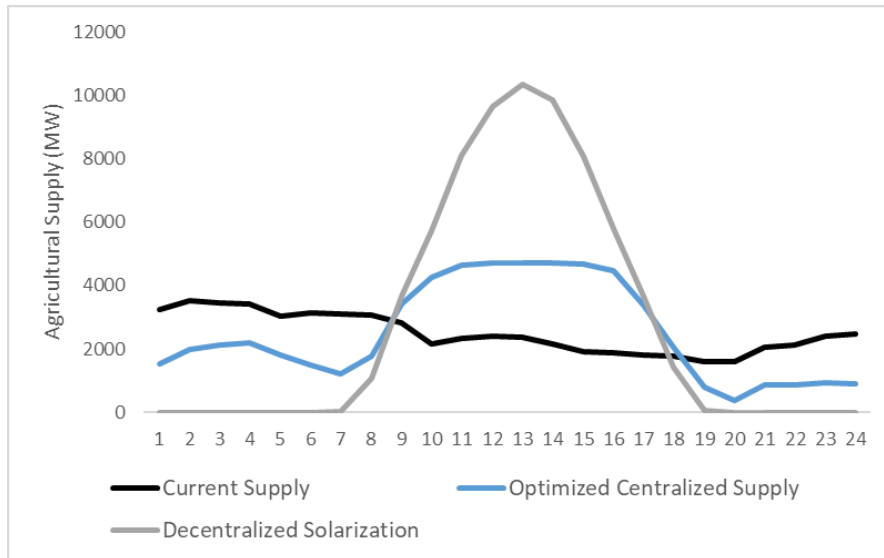
3.4. Centralized vs. decentralized solar deployment

Solar deployment in India has so far been dominated by centralized, utility scale solar power plants. Of the total utility scale solar capacity of 34,197 MW, only 20 percent is decentralized solar [38]. The recently launched Pradhan Mantri Kisan Urja Suraksha evam Utthaan Mahabhiyan (PM-KUSUM) scheme by the government of India could accelerate investment in decentralized solar. Component-C of the scheme incentivizes solarization of grid connected irrigation pumps at farm level, wherein the government will provide subsidies up to 70% of the capital cost [28]. The scheme can be operationalized in either net-metering or gross-metering mode. In the net-metering mode, the agriculture pump will continue to run at the rated capacity taking power from solar panels and the balance power from grid, if required. Since the pumps will be kept 'ON' during the sunshine hours from morning to evening, it is possible that a portion of the pumps would run during peak hours drawing power from the grid and feeding surplus solar power during the off-peak hours. In the gross-metering mode, the pump will only be run on solar power as in case of stand-alone solar pump and no power will be drawn from the grid for the operation of the pump. The existing motor pump set will have to be replaced to run directly on solar power. When solar power is not being used for irrigation, it can be fed into the grid.

This analysis represents solarization with gross metering in the power system model. In the decentralized solarization scenario, the connected agricultural load (11500 MW) is shifted to decentralized solar pumps. Decentralized solar of an amount equal to 1.5 times the agricultural load (17500 MW), the maximum for which subsidy is available under the PM-KUSUM scheme is modeled. The resulting system is equivalent to the one with 50% RE (ratio of solar: wind = 1:1). Because solarized agricultural pumps can vary their output with the energy generated from the panels, they can absorb the variations in solar generation. In addition, the local grid constraints that limit the amount of power supplied to agricultural in any period in other scenarios need not be applied. The maximum load of the agricultural pumps in any hour in the decentralized scenario can thus be higher than the centralized 8-hour case and is considered equal to generation from the associated solar pumps (see 2.3).

At the system level, this has the result that solarization is able to achieve the ideal optimal agricultural load curve for high solar penetration (Figure 8). Accordingly, at 50% share of RE, the total system cost in the solarization scenario is lower than that in the centralized 8-hour supply. From a power system flexibility perspective, while there are minimal incremental gains in reducing unit starts for coal and gas power plants, ramping requirement is further reduced under the solarization scenario (Figure A.3). Crucially, solarization allows for greater absorption of renewable energy in the grid. Solar and wind curtailment reduces from 3.1% and 2.9% respectively in the centralized-supply scenario to negligible amounts in the solarization scenario.

Figure 8: Agricultural supply in centralized 8-hour supply vs. decentralized solarization scenarios. These results are derived for a model with 50% RE share and 1:1 ratio of solar to wind in RE generation.



There are however limits to solarization of agricultural pumps at scale. First, solarization with gross metering requires an additional expense by farmers to convert their solar pumps to run directly on solar power. Second, unchecked use of solar panels (with zero marginal cost electricity) can worsen the problem of ground water utilization, which is currently controlled by limiting the supply of electricity. Importantly, time varying feed-in-tariffs would need to be used to provide an incentive to farmers to feed electricity into the grid at a time when it is beneficial for the system. Well-designed feed-in-tariffs can also provide additional income to farmers, besides providing incentives for conserving water [39]. If such feed-in-tariffs are priced correctly, farmers can be moved from a system of load control to true demand response, whereby they are suitably reimbursed for the system services that they provide to the power system.

4. Conclusion

Agricultural pumping load is seen as a liability by electricity utilities in India due to poor paying capacity of the farmers and heavy subsidization. Farmers are supplied electricity only for 8 hours a day, late in the night when demand from other sources is lacking. This article shifts perspective by looking at the value of agricultural pumping demand as demand side resource to the power system.

Enabled by a system of separate power supply for irrigation (feeder segregation), agricultural pumping load is being used to flatten the load curve but its value to the system has largely been ignored. Using data collected on hourly electricity supply to 123 agriculture groups in two distribution utilities in the Indian state of Gujarat, this analysis shows that direct load control of the agricultural pumps results in reduction of about 5% in total system costs. This occurs *inter alia* by allowing for a smoother operation of coal power plants. The cost savings are equivalent to USD 6.28 per MWh or INR 0.44 per unit of consumption by agricultural customers. This is a substantial amount when compared to the energy charges of INR 0.60 per unit of consumption for irrigation pumps in 2018 [23].

The value of such demand side management will increase as the share of RE in power generation increases. In the future, it would be system optimal to move agricultural supply to daytime hours if the share of solar in RE generation increases. This analysis suggests that such management of the pumping load can help reduce the curtailment of renewable energy by 3–6% at 50% RE share and lower cycling of coal power plants. Using agricultural demand response reduces the marginal costs of RE integration (flexibility costs and the utilization effect) by 21%, from USD 25/MWh_{RE} to USD 19/MWh_{RE}. Since under the current regulatory setup these costs are likely to borne by electricity customers, flexible agricultural load can improve general consumer welfare.

A potential limiting factor can be that such direct load control over agricultural pumps may no longer be possible when the recently launched PM-KUSUM scheme to solarize individual agricultural pumps is implemented. But this paper shows that, if correctly implemented, this decentralized approach to deployment of solar can actually be beneficial from the system perspective. This should be considered in the cost-benefit analysis of incentivizing decentralized deployment of solar for irrigation in India.

Neither the predominance of agricultural load in the power system, nor the usefulness of agricultural demand response is unique to India. Agricultural consumption is a major source of demand in developing countries. More research into ways of exploiting this demand side resource would provide policymakers and system planners across the developing world with an additional, cheap flexibility option to facilitate the integration of renewables.

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Supplementary Material

The data collected on end-user profiles and other inputs of the production cost model are available on the Github page of the project (<https://github.com/tarun-hertie/Agricultural-Demand-Response-in-India>).

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Appendix

Gujarat farmers are divided in 124 groups, each consisting of a collection of villages. Electricity is supplied to each agricultural group for 8 hours a day based on a schedule that is changed on a weekly basis. Electricity is supplied to each agricultural group for 8 hours a day based on a schedule that is changed on a weekly basis. Electricity is supplied to each agricultural group for 8 hours a day based on a schedule that is changed on a weekly basis.

Figure A.1: Example of the schedules published by PGVCL on its website.

Paschim Gujarat Vij Company Limited									
Load Management Unit, 400 kV sub-station campus, JETPUR Phone: 02823-225133 Fax: 02823-226308 Email : eelmu.pgvcl@gmail.com Reg. & Corporate Office, "Paschim Gujarat Vij Seva Sadan" Off. Nana Mava Road, Laxminagar, Rajkot - 360 004 CIN: U40102GJ2003SGC042908; Phone: (0281)2360425, 2360427; Fax : 2360428; Email: info.pgvcl@gmail.com; Web site: www.pgvcl.com									
Power Supply Schedule for Agriculture Groups									
Effective Period: 10/11/2019 to 16/11/2019 (WEEK-1)									
Message No: 2086		Date: 08/11/2019			Time: 17:00 Hrs.				
From: Executive Engineer, LMU, PGVCL, Jetpur									
To: All SE(O&M/TR) / EE(O&M/TR) under PGVCL area & EE(SUB-SLDC) Jetpur									
<ul style="list-style-type: none"> Latest schedule and other information is available on our website www.pgvcl.com 				<p>Time schedule for supplying 08:00 hrs 3 phase power to Agriculture Groups of PGVCL as approved by State Load Despatch Center, Gotri, Baroda. This schedule will be effective from Saturday evening, i. e. from 19:45 Hrs of 09/11/2019. Group timings are subject to change.</p>					
Circle / Area	No	Group	Load (MW)	Timing of 3 Phase Power Supply	Circle / Area	No	Group	Load (MW)	Timing of 3 Phase Power Supply
BHAVNAGAR	1	E11	32	05:30 - 13:30	BHUJ	33	J11	68	00:00 - 08:00
	2	E12	53	19:45 - 03:45		34	J12	58	12:00 - 20:00
	3	E13	51	20:00 - 04:00		35	J13	51	04:00 - 12:00
	4	E14	43	08:00 - 16:00		36	J14	72	20:00 - 04:00
	5	E15	53	00:30 - 08:30		37	J15	72	00:15 - 08:15
	6	E16	28	10:00 - 18:00		38	J16	74	04:45 - 12:45
JUNAGADH	7	F11	30	10:15 - 18:15	39	J17	83	20:15 - 04:15	
	8	F12	45	20:00 - 04:00	40	J18	77	10:00 - 18:00	
	9	F13	41	04:30 - 12:30	41	R11	78	01:00 - 09:00	
	10	F14	42	22:00 - 06:00	42	R12	43	12:00 - 20:00	
	11	F15	33	20:15 - 04:15	43	R13	70	20:00 - 04:00	
	12	F16	28	04:30 - 12:30	44	R14	55	04:00 - 12:00	
AMRELI	13	G11	57	04:15 - 12:15	45	R15	41	00:15 - 08:15	
	14	G12	74	01:00 - 09:00	46	R16	21	12:15 - 20:15	
	15	G13	86	00:00 - 08:00	47	R17	32	20:15 - 04:15	
	16	G14	52	10:45 - 18:45	48	R18	19	04:30 - 12:30	
	17	G15	93	20:30 - 04:30	49	V11	21	06:15 - 14:15	
	18	G16	58	05:45 - 13:45	50	V12	20	20:45 - 04:45	
JAMNAGAR	19	H11	30	04:30 - 12:30	51	V13	18	12:15 - 20:15	
	20	H12	36	00:00 - 08:00	52	V14	22	22:30 - 06:30	
	21	H13	36	20:00 - 04:00	53	B11	31	10:15 - 18:15	
	22	H14	25	08:00 - 16:00	54	B12	32	19:45 - 03:45	
	23	H15	34	00:45 - 08:45	55	B13	32	04:15 - 12:15	
	24	H16	24	10:45 - 18:45	56	B14	45	22:30 - 06:30	
SURENDRANAGAR	25	I11	14	20:30 - 04:30	57	M11	7	01:15 - 09:15	
	26	I12	8	10:30 - 18:30	58	M12	3	10:30 - 18:30	
	27	I13	13	00:00 - 08:00	59	M13	3	05:30 - 13:30	
	28	I14	10	05:15 - 13:15	60	M14	5	20:15 - 04:15	
	29	I15	13	21:15 - 05:15	61	M15	22	04:15 - 12:15	
	30	I16	10	12:00 - 20:00	62	M16	17	01:15 - 09:15	
MORBI	31	I17	10	04:00 - 12:00	63	M17	15	08:15 - 16:15	
	32	I18	8	01:00 - 09:00	64	M18	21	20:15 - 04:15	

NOTE: (1) Please pass this message up to sub-station and sub-division level to concerned & for public display.

Figure A.2: Example of the schedules published by PGVCL on its website.

UTTAR GUJARAT VIJ COMPANY LIMITED, MEHSANA.				
LMU, AREA LOAD DESPATCH CENTRE, GANDHINAGAR.				
AG GROUP TIME SCHEDULE FOR THE DATE : 26.01.2020 to 01.02.2020				
MSG NO : LMU(ALDC) / UGVCL / 467 Dated: 23.01.2020				
The weekly 3-Ph Power supply schedule to AG Groups of UGVCL for the week is as under. This is to be implemented with effect from -26.01.2020, Sunday (I.e. From the night of Date 26/01/2020 Saturday , At 20:00 Hrs.)				
Sr. No	GETCO Division / AREA	Ag. Group	Apx.Load In MW	Schedule Time
1	Mehsana	A11	65	06:30 TO 13:30
2		A12	70	20:30 TO 04:30
3		A13	45	12:30 TO 20:30
4		A14	80	21:00 TO 06:00
5	Vijapur	B11	75	20:15 TO 04:15
6		B12	70	12:00 TO 20:00
7		B13	80	00:00 TO 08:00
8		B14	80	06:30 TO 13:30
9	Jamla	B15	85	16:00 TO 23:00
10		B16	85	23:00 TO 07:00
11		B17	45	07:00 TO 16:00
12		B18	85	23:30 TO 07:30
13	Chhatral, Narol, Ranasan, Viramgam	C11	115	20:00 TO 04:00
14		C12	80	04:00 TO 12:00
15		C13	80	12:00 TO 20:00
16		D11	105	20:30 TO 04:30
17	Kheralu	D12	70	04:30 TO 12:30
18		D13	75	12:30 TO 20:30
19		K11	70	06:15 TO 13:15
20		K12	95	22:00 TO 06:00
21	Palanpur	K13	80	08:00 TO 14:00
22		K14	90	20:30 TO 04:30
23		L11	85	08:00 TO 14:00
24		L12	85	08:00 TO 14:00
25	Dhanera (Thavar)	L13	95	22:00 TO 08:00
26		L14	75	20:45 TO 04:45
27		O11	135	14:00 TO 22:00
28		O12	125	22:00 TO 06:00
29	Tharad	O13	100	08:00 TO 14:00
30		O14	70	13:00 TO 21:00
31		O15	85	21:00 TO 06:00
32		O16	50	06:00 TO 13:00
33	Patan	O17	115	18:30 TO 00:30
34		O18	90	00:30 TO 08:30
35		O19	85	08:30 TO 16:30
36		P11	80	07:00 TO 16:00
37	Deodar	P12	55	12:00 TO 20:00
38		P13	85	20:30 TO 04:30
39		P14	90	00:00 TO 08:00
40		G11	115	12:00 TO 20:00
41	Dhanera (zerda)	G12	130	20:00 TO 04:00
42		G13	80	04:00 TO 12:00
43		G14	35	8:00 TO 17:00
44		S11	105	13:00 TO 21:00
45	Deesa	S12	110	21:00 TO 06:00
46		S13	70	06:00 TO 13:00
47		S14	15	06:00 TO 13:00
48		S15	185	12:00 TO 20:00
49	Dhansura, Idar, Aglyol	S16	180	00:00 TO 08:00
50		S17	115	04:00 TO 12:00
51		S18	75	23:00 TO 07:00
52		M11	80	08:30 TO 16:30
53	Dhansura, Idar, Aglyol	M12	140	16:30 TO 00:30
54		M13	90	00:30 TO 08:30
55		T11	40	06:30 TO 13:30
56		T12	70	13:30 TO 21:30
57		T13	95	21:30 TO 05:30
58		N11	80	08:00 TO 16:00
58				17:00 TO 21:00
59		N12	55	04:00 TO 08:00
59	16:00 TO 19:00			

Remarks : (1) Rescheduling of power supply may happen due to routine maintenance of substation or in emergency cases. It is requested to contact local substation if power supply differs from published time schedule.

Figure A.3: System metrics showing the impact of decentralized solarization of agricultural pumps. These results are derived for RE shares of 50% considering 1:1 ratio of solar to wind in RE generation. In the box plots, the points represent individual power plants.

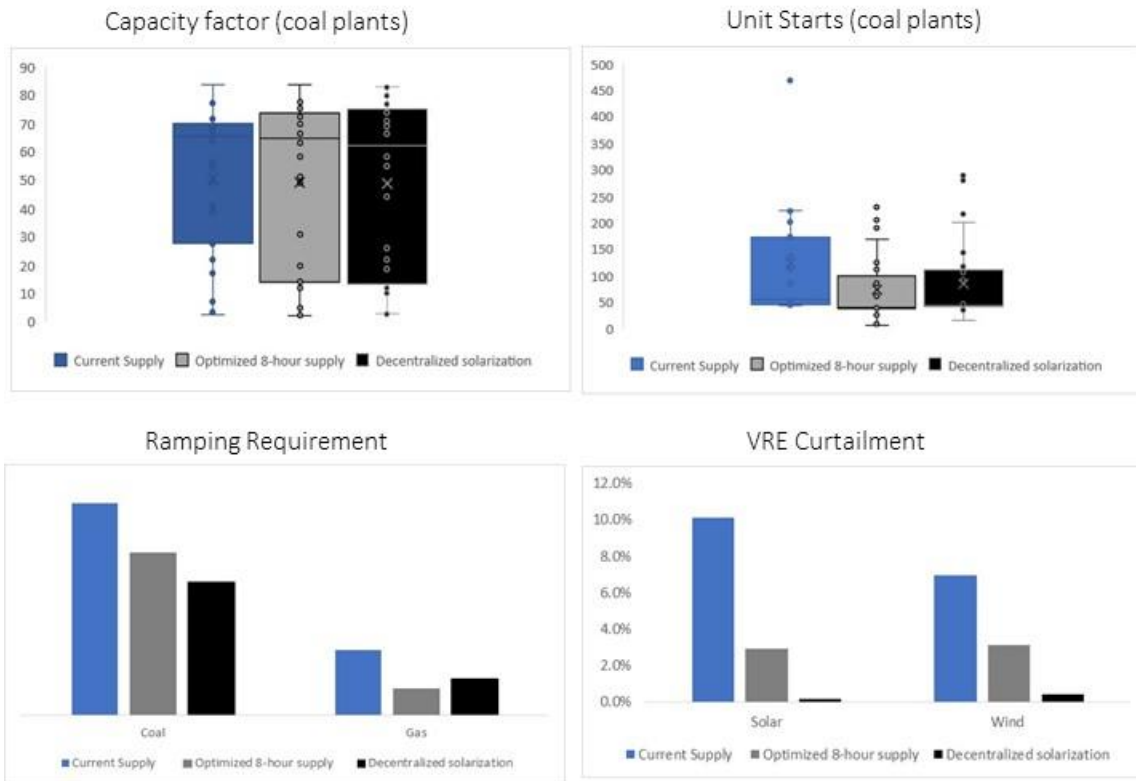


Figure A.4: Month-wise actual and optimized supply hours to agriculture under various renewable energy scenarios. Monsoon months include June, July, August, and September. The supply curves are derived for models with 50% RE share.

January



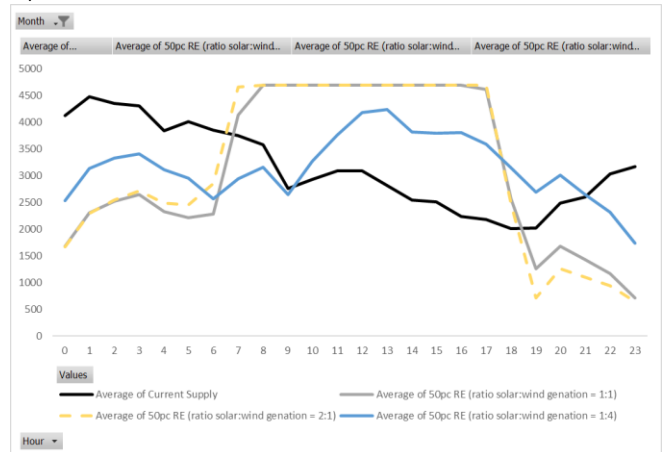
February



March



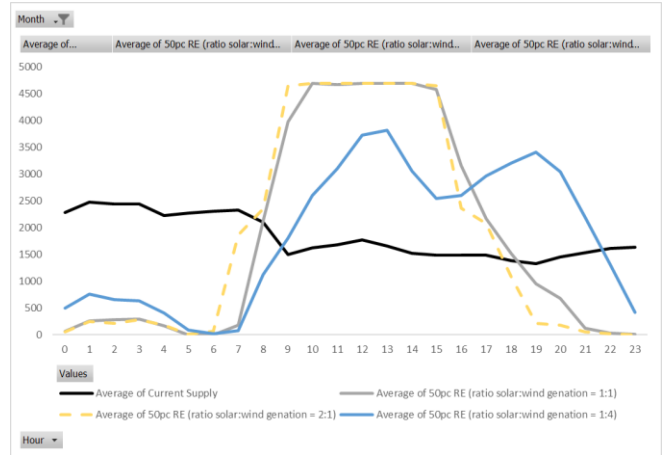
April



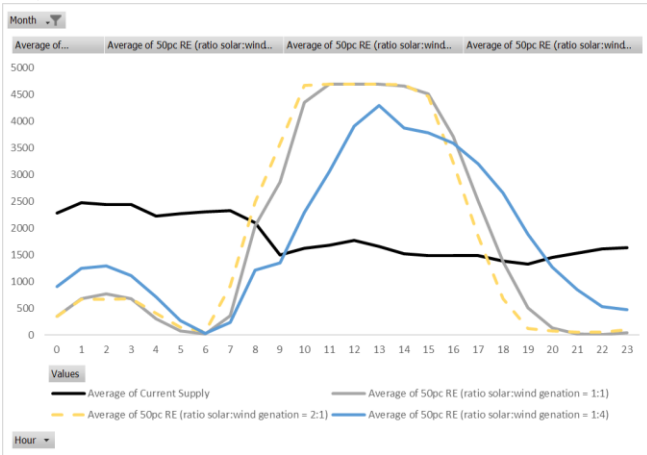
May



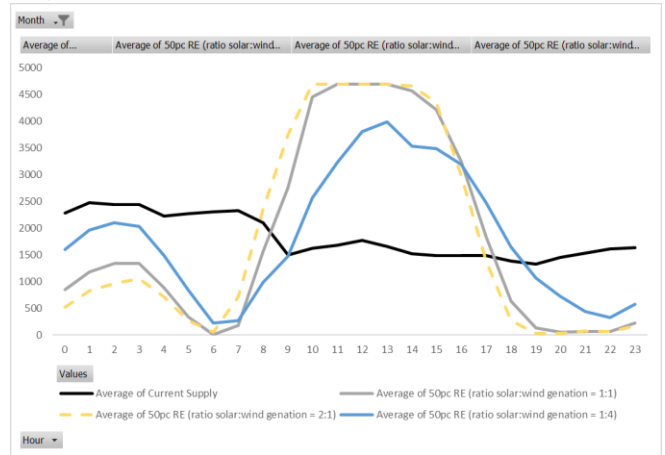
June



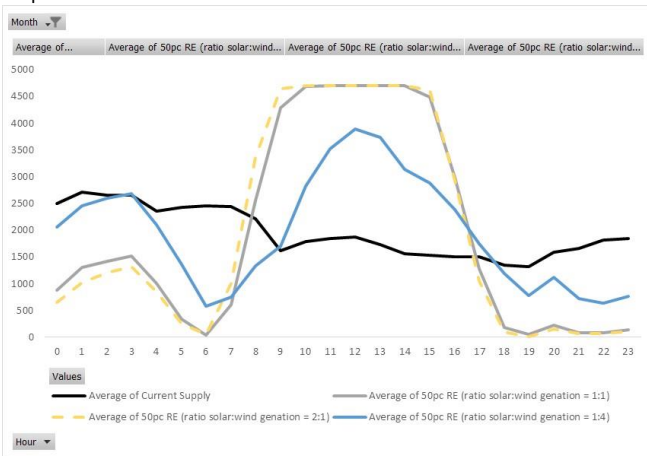
July



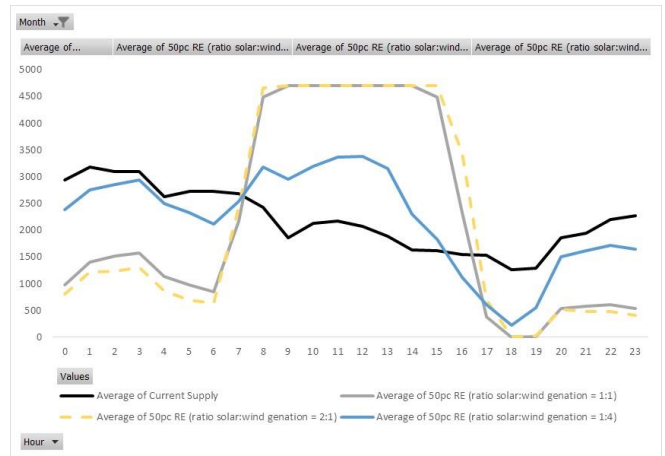
August



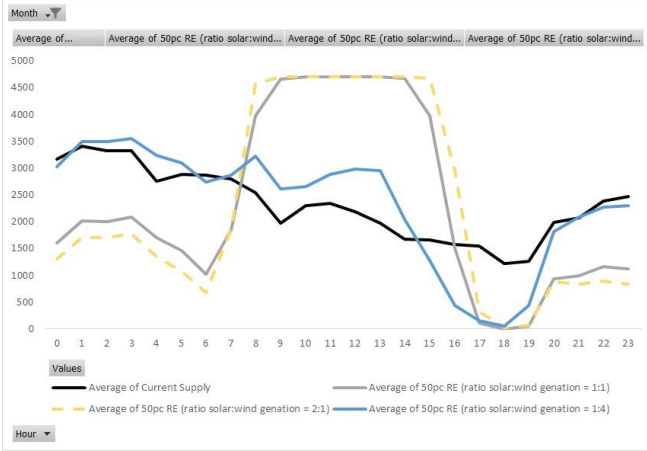
September



October



November



December

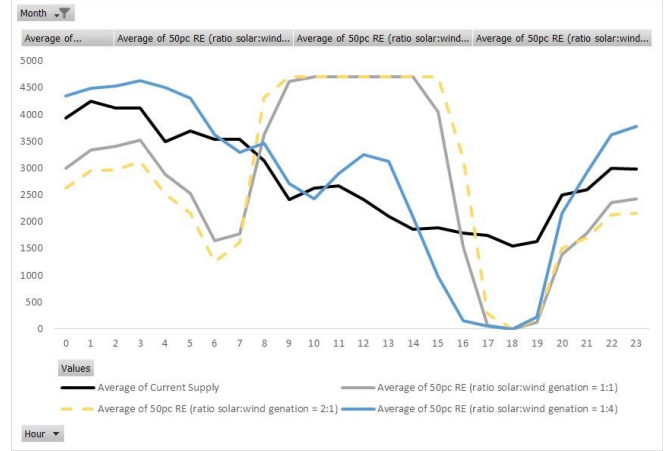


Figure A.5: Actual and optimized supply hours to agriculture during monsoon and non-monsoon months under various scenarios. These results are derived for power plant capacities and share of RE (13%) as in 2018-19.

