Exploring Electricity Supply-Mix Scenarios to 2030

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Executive Summary

This paper develops and studies three capacity scenarios for the Indian power system to 2030, summarized in the table below.

Scenario Name	Scenario Logic	Coal Capacity (MW) and Generation Share (%) in 2030		RE Capacity (MW) and Generation Share (%) in 2030	
Current Policy Scenario (CPS)	175 GW RE by 2022 and then capacity addition according to the NEP	238131	54%	355000	30%
Current Trajectory Scenario (CTS)	More modest RE trajectory; greater coal additions in the 2020s	262177	61%	289000	24%
High RE Scenario (HRES)	Maximize RE by 2030; no new coal beyond the current pipeline	191711	50%	421014	34%

Levelized Cost of Electricity and System Tariff

We calculate the levelized cost of electricity (LCOE) and system tariff, calculated as the ex-bus bar cost of energy supply, excluding transmission and distribution costs and excluding the additional costs of grid integration of variable RE. The table below displays the key results.

Description	2018	2022	2025	2030
Ground-Mounted Solar PV LCOE (R/kWh)	2.87	2.58	2.42	2.30
Onshore Wind LCOE (R/kWh)	2.85	2.75	2.69	2.58
Pithead Super Critical Coal LCOE (R/kWh)	3.64	3.97	4.26	4.82
Non-Pithead Super Critical Coal LCOE (R/kWh)	4.97	5.53	6.01	6.95
CPS System Tariff (R/kWh)		5.45	5.56	5.55
CTS System Tariff (R/kWh)		5.35	5.44	5.50
HRES System Tariff (R/kWh)		5.48	5.48	5.40

RE was found to be the cheapest source of incremental generation, even considering sensitivities around capital and financing costs. A high RE scenario is found to have a deflationary impact on system tariff later in the projection period.

Flexibility Needs and System Tariff with Consideration of Flexibility <Level B>

The three scenarios developed in this paper were analysed from a flexibility perspective using a simple model that simulated hourly system operation at an all-India level, abstracting away from transmission constraints. Assuming no additional flexibility beyond what is currently in the Indian power system, the additional flexibility needs were found to be considerable by 2030, even in the CTS which considers more coal addition and less RE. Additional flexible resources were found to be necessary by 2030 in all scenarios. Particular challenges include: daily excess energy production at midday, deficit energy production during the evening peak-demand hour, and low RE output during winter. We calculated the additional system-wide cost of providing this flexibility using a stylized combination of additional coal, gas, storage, and modest demand response. This was found to increase the system tariff in all scenarios, and most strongly in the HRES. The total system tariff, including flexibility, is almost the same across scenarios (5.83 in the CPS, 5.78 in the CTS, and 5.80 in the HRES), indicating that a high RE system can be cost-effective even considering the flexibility costs.

Introduction and Objectives

The objective of this paper is to present integrated electricity capacity scenarios to 2030, and to explore their implications for India's electricity system. These scenarios have not been developed using a cost-optimizing capacity expansion model, but rather a scenario-based approach. They are not intended as ends in themselves, but rather as the starting points for studying the flexibility and renewable energy (RE) grid-integration challenges by 2030. The scenarios have been developed to provide an input to that work (Work Package 3 of the ongoing Energy Transitions Commission (ETC) India project). At the same time, some analysis of the flexibility issue has already been done in order to explore the issue of system balancing by 2030 at a macro level. The objective in this regard is to provide an initial analysis on flexibility issues, so that readers, commenters, and users of the scenarios presented in this paper can also give due consideration to flexibility issues.

These scenarios will be fed into Work Package 3 of the ETC India project, where the issue of flexibility needs, options, and costs will be studied (led by Climate Policy Initiative [CPI]), alongside spatially explicit, hourly dispatch modelling of the entire electricity system in 2030 (led by the National Renewable Energy Laboratory [NREL]). See the section below describing the structure of the project.

Thus, the objective of this discussion paper is to present the scenarios on which the further study of RE grid integration will be based; and analyse these scenarios in terms of the rates of capacity expansion, cost, investment requirement, etc.

Emerging conclusions for discussion and feedback are presented in the final section.

Overview of the How This Paper Fits into the ETC India Project

The objective of the ETC India project is to examine the technical, financial, and market aspects of power system transition to a high share of variable renewables by 2030 in India. With this overarching objective in mind, the project is divided into four work packages, which are as follows:

1. Work package 1: Electricity demand projections for 2030 in each consumption category and for major end uses. A TERI report published in conjunction with the present paper summarizes the outputs of this work package.
2. Work package 2: Supply-side scenarios to 2030, and their analysis in terms of investments, tariffs, and costs, as well as the initial assessment of flexibility challenges. This is the present paper.
3. Work package 3, part 1: Assessment of the flexibility needs under the supply scenarios developed in work package 2, and analysis of the options and costs to meet these flexibility needs. The companion report published concurrently with this report represents the output of this work package.
4. Work package 3, part 2: Modelling the dispatch and hourly operation of the power system in 2030 using the spatially disaggregated PLEXOS model. This work will be conducted by the NREL, and is getting underway now that the above three outputs are ready.
5. Work package 4: Socio-economic aspects of the power system transition. This work is ongoing.

Scenario Framework

Supply scenarios have been prepared by considering electricity demand growth of 6.0% year-on-year to 2030, with grid demand reaching 2040 TWh (excluding the Aggregate Technical and Commercial (AT&C) losses, captive power, and rooftop solar) by 2030. This is broadly in line with the demand trajectory implied by the 19th Electric Power Survey (EPS) of the Central Electricity Authority, and was chosen so as to ensure comparability between these scenarios and the 2018 National Electricity Plan (NEP), based on the EPS. Three capacity scenarios are considered:

1. Current Policy Scenario (CPS): This capacity scenario

has been prepared by considering the major policy drivers of the Indian power sector, such as the 175 GW RE target by 2022, the projections of the 2018 NEP to 2027, and various policy statements by the Ministry of New and Renewable Energy (MNRE). After the terminal year of the capacity scenarios of the NEP (2027), an assumption of continued trends is made to derive 2030 capacity numbers.

2. Current Trajectory Scenario (CTS): This scenario has been prepared in order to examine a possible current trajectory for the power system, given the current commercial and ground realities. It should be noted that it remains a scenario not a forecast, and is based on the TERI analysts' assessment and judgements. A number of forces were considered. Firstly, somewhat lower capacity addition in the coal sector is considered for 2022, in view of the current financial stress and lack of progress seen in a number of under-construction projects. Secondly, it is assumed that the RE targets for 2022 are missed by a moderate margin, given the current challenges being faced by the rooftop solar segment and ground-mounted solar segment (safeguard duty, tender cancelations, etc). After 2022, the shortfall of dispatchable power and the growing energy requirement leads to a situation in which additional coal-based capacity is added, as well as continued moderately aggressive expansion of RE.

3. High RE Scenario (HRES): In the HRES, no coal power addition has been considered after the completion of the under-construction pipeline in 2022. In addition, a higher growth rate has been assumed for RE technology, mainly in solar and wind, after 2022. Thus, by 2030, the HRES sees a higher level of installed RE capacity, as compared to the CPS.

Table 1 presents the main assumptions for the three scenarios.

Production Capacities by Scenario

CPS

The CPS is a policy-driven scenario, considering the NEP, the targets of 175 GW of RE by 2022, and 275 GW of RE by 2027. The same growth rate has been considered and

Table 1: Capacity additions and retirements to 2030 in each scenario

	Current Policy Scenario (CPS)		Current Trajectory Scenario (CTS)		High RE Scenario (HRES)	
Technology	Capacity addition (+) / retirement (-)	CAGR* of net additions (%)	Capacity addition (+) / retirement (-)	CAGR of net additions (%)	Capacity addition (+) / retirement (-)	CAGR of net additions (%)
Coal	(+) 85 GW	1.5%	(+) 109 GW	2%	(+) 38 GW	-0.2%
	(-)44 GW		(-) 44 GW		(-) 44 GW	
Hydro	(+) 28 GW	3.7%	(+) 18 GW	3%	(+) 25 GW	3%
Nuclear	(+) 10 GW	7%	(+) 10 GW	7%	(+) 10 GW	7%
Solar	(+) 168 GW	18%	(+) 130 GW	16%	(+) 208 GW	20%
Wind	(+) 98 GW	11%	(+) 89 GW	10%	(+) 126 GW	13%
Small Hydro & Biomass	(+) 20 GW	7% / 7%	(+) 2 GW	1% / 1%	(+) 18 GW	7% / 7%
	(6 GW of SH*, 14 GW of BM),		(0.5 GW of SH, 1.5 GW of BM),		(6 SH, 12 BM),	

**SH stands for small hydro, BM for biomass, and CAGR for compound annual growth rate.*
Note: No addition has been considered in gas power capacity. Capacity addition, retirement, and CAGR of net additions are from 2018 to 2030.
Source: TERI modelling and scenario-building

Table 2: Capacity assumptions in the CPS

Technology	2018		2022		2027		2030	
	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity
Coal	197172	57%	217283	45%	238131	38%	238131	34%
Gas	24897	7%	24897	5%	24897	4%	24897	4%
Diesel	838	0%	838	0%	838	0%	838	0%
Nuclear	6780	2%	10080	2%	16880	3%	16880	2%
Hydro	45293	13%	51301	11%	63301	10%	72901	10%
Solar	21651	6%	100000	21%	150000	24%	190000	27%
Wind	34046	10%	60000	13%	100000	16%	132000	19%
Small Hydro	4486	1%	5000	1%	8000	1%	10400	1%
Biomass	8839	3%	10000	2%	17000	3%	22600	3%
Total installed capacity	344002	100%	479399	100%	619047	100%	708647	100%

Source: TERI modelling and scenario-building

Table 3: Cumulative CAGR for each technology from 2018, CPS

Technology	Cumulative CAGR% from 2018		
	2022	2027	2030
Coal	2.5%	2.1%	1.5%
Gas + Diesel	0.0%	0.0%	0.0%
Nuclear	10.4%	10.7%	7.3%
Hydro	3.2%	3.8%	3.7%
Solar PV + Rooftop	46.6%	24.0%	18.2%
Wind	15.2%	12.7%	11.0%
Small Hydro	2.7%	6.6%	6.7%
Biomass	3.1%	7.5%	7.5%
Total	8.7%	6.7%	5.7%

Source: TERI modelling and scenario-building

extrapolated for the next four years. Non-fossil capacities will be about 50% of the installed capacity by the end of 2022, and further increased to 63% by 2030. Table 2 displays the main capacity assumptions for the CPS.

Further details for the CPS are as follows:

Coal power: Currently, coal-based power plants account for about 57% of the total power-generating capacity of India. We considered a gross addition of 85 GW of coal by 2027 and a retirement of around 44 GW of old plants, which do not have enough space provision for flue gas desulfurization (FGD) and other pollution-control instruments required to meet the new environment norms; and are generally less efficient while being more expensive to operate and maintain. This contributes to the net capacity addition of 41 GW in the coal fleet by 2027, and we do not consider any further additions to 2030.

Hydropower: A cumulative capacity addition of 6 GW (at 3.2% CAGR) is expected to be commissioned during 2018–22. Beyond 2022, a higher rate of growth (3.8% CAGR) in hydro plant installation is considered, adding 28 GW of hydro capacity to 2030. The expected hydro capacity by 2030 will be 73 GW. Box 1 discusses some of the challenges related to this level of hydro capacity addition.

Nuclear power: Three nuclear power plants are expected to be commissioned during 2018–2022, contributing a net capacity addition of 3.3 GW to the supply mix. These three stations are the Kakrapar Atomic Power Plant (2*700 MW), the Rajasthan Atomic Power Station (2*700 MW), and the Kalpakkam fast breeder reactor (500 MW).

Further, a net capacity addition of 6.8 GW is projected to be commissioned by 2027, according to the NEP. One of the major capacity additions will be from expansion of the Kudankulam Nuclear Power Project (4*1000 MW), two units of which are already at the early stage of construction and are projected to be completed by 2025–26. Box 1 deals with some of the challenges related to the expansion of hydro and nuclear power capacities, as envisaged in the CPS.

Box 1: The Project Pipeline for Nuclear and Hydro

The CPS envisages a net addition of 10.1 GW of nuclear capacity, and 27.6 GW of large hydro between 2018 and 2030 (see Table 2). In view of the long lead-times, capital intensity, history of time and cost overruns, and social opposition (particularly to large hydro), this can be seen to be an ambitious agenda of capacity addition from these technologies. Table 4 displays the project pipeline for nuclear and large hydro, in the context of the envisaged capacity addition by 2030.

Although there is substantial capacity under permitting for both technologies, completing the required capacity addition by 2030 is challenging. This appears particularly so for large hydro, for which the as-yet-uninitiated capacity (20375 MW) is more than what has been added in the 16 years between 2001 and 2017 (20049 MW). With respect to nuclear, the incremental capacity required is less, but the long lead-time means that meeting this capacity addition by 2030 would require that new projects move expeditiously through the pipeline and commence construction by the early 2020s at the latest.

The analysis in this paper suggests that, under the CPS, both from an annual energy requirement perspective (hydro and nuclear) and from a flexibility perspective (hydro), the additional capacities from hydro and nuclear envisaged by 2030 would be highly desirable. Failure to achieve them could potentially constrain the growth of renewables, necessitate other balancing resources, and possibly entail the addition of further coal to meet the annual energy requirement.

Gas power: The gas-based power plants in India are mainly combined cycle gas stations. These currently run at a lower plant load factor (PLF) due to high variable cost, as a result of the limited supply of cheap domestic gas and high cost of imported LNG. In FY2017–18, the PLF of the gas-based generation fleet was around 23%. In the CPS, there will no gas-based capacity addition during the period up to 2027, as per the NEP, and we extrapolate that to 2030.

RE: By March 2018, the RE installed capacity was 69 GW, a 20.1% share in the capacity mix of India, comprising 34 GW of wind, 22 GW of solar, 4.5 GW of small hydro, and a remaining 8.8 GW of biomass/cogeneration. Significant reductions have been seen in tariffs for solar (Rs 2.44/kWh) and wind (Rs 2.64/kWh), due to competitive bidding and policy facilitation. The Government of India has set a target of 175 GW of RE capacity by 2022. This includes 60 GW from wind power, 60 GW from ground-mounted PV and 40 GW from rooftop PV, 10 GW from biomass power, and 5 GW from small hydropower. A CAGR of 26% is required to achieve this ambitious target, if RE capacity is considered as a whole. The individual CAGRs required for solar, wind, small hydro, and biomass are 47%, 15%, 3%, and 3%, respectively. Further, to achieve the 275 GW of RE installed capacity by 2027, as envisaged in the NEP, a CAGR of 9.5% is required in the period 2022–2027. If the same growth rate continues till 2030, the RE capacity will be 355 GW—50% of the total installed capacity.

Table 4: Project pipeline for nuclear and large hydro (MW)

Technology	2018 Capacity	Under Construction Plant to be Commissioned by ca. 2022–2025	Required Capacity Addition by 2030 to Meet CPS Target, After Completion of Under-Construction Capacity	Capacity Under Permitting
Large Hydro	45293	7234	20375	55195
Nuclear	6780	5300	4800	46900

Source: TERI analysis, based on data from GlobalData (2018)

CTS

The CTS follows a possible trajectory for the Indian power system considering the current on-the-ground commercial realities and challenges in achieving the policy objectives of the Government of India. The target set by the Government of India of 175 GW of RE by 2022 is highly ambitious, and requires, as noted earlier, a CAGR of 26% from 2018 to 2022. The current growth rate is not as high as required, though there is a strong push from the Government of India to achieve the said target. The CTS considers a slightly lower growth rate for RE, which is in line with the current rates, and considers delays in achieving the rooftop PV targets as well as recent moves which may delay the ground-mounted solar PV pipeline (safeguard duty, tender cancellations, tariff capping, infrastructure bottlenecks, etc).

In the CTS, we have considered a slower short-term growth rate in the addition of coal power plants to the supply mix. The recent lower-than-projected demand growth and stronger-than-expected capacity additions have led to a situation in which DISCOMS are oversupplied with power purchase agreements (PPAs) and are reluctant to sign new ones. Thus, a significant portion of under-construction coal capacity is stalled due to an inability to sign PPAs, access fuel supply agreements (FSAs), and negotiate additional debt financing to allow project completion. Currently, at least 16 GW of under-construction plants are without PPAs. Given the current conditions, it seems possible that a significant share of the under-construction coal capacity will not be completed.

In the CTS, the non-fossil share in capacity will be about 47% by 2022 and further increased to 56% by the end of 2030.

Coal and gas: As discussed earlier, this scenario considers a slower growth rate of coal power addition due to the current financial stress in the sector. However, the increase in demand and more moderate RE penetration by 2022 will start to affect the demand–supply balance shortly after 2022. This higher demand, the absence of dispatchable capacities, and the assumed slower progress on grid flexibility and RE integration are assumed to lead to the addition of further coal capacities after 2022. In addition, a retirement of 44 GW of coal plant is considered, the same as in the CPS. The CTS, thus, results a higher coal capacity by the end of 2030. No addition or retirement of gas power plants has been considered in this scenario.

RE: A slower growth rate as compared to the targeted rate to achieve 175 GW of RE will lead to a lower RE addition into the system by 2022. Thus, in the CTS the RE capacity

Table 5: Capacity assumptions in the CTS

Technology	2018		2022		2027		2030	
	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity
Coal	197172	57%	208999	47%	227177	41%	262177	40%
Gas	24897	7%	24897	6%	24897	4%	24897	4%
Diesel	838	0%	838	0%	838	0%	838	0%
Nuclear	6780	2%	10080	2%	16880	3%	16880	3%
Hydro	45293	13%	50960	12%	62960	11%	62960	10%
Solar	21651	6%	70000	16%	115000	21%	151000	23%
Wind	34046	10%	60000	14%	95000	17%	123000	19%
Small Hydro	4486	1%	5000	1%	5000	1%	5000	1%
Biomass	8839	3%	10000	2%	10000	2%	10000	2%
Total Installed Capacity	344002	100%	440774	100%	557752	100%	656752	100%

Source: TERI assumptions and scenario-building

Table 6: Cumulative CAGR for each technology from FY2018, CTS

Technology	Cumulative CAGR% from FY 2018		
	2022	2027	2030
Coal	1.5%	1.6%	2.2%
Gas + Diesel	0.0%	0.0%	0.0%
Nuclear	10.4%	10.7%	7.3%
Hydro	3.0%	3.7%	2.6%
Solar PV + Rooftop	34.1%	20.4%	16.1%
Wind	15.2%	12.1%	10.4%
Small Hydro	2.7%	1.2%	0.8%
Biomass	3.1%	1.4%	1.0%
Total	6.4%	5.5%	5.1%

Source: TERI assumptions and scenario-building

is 145 GW by 2022, consisting of 70 GW of solar, 60 GW of wind, 5G W of small hydro, and 10 GW of biomass. These figures imply a CAGR of 20% year-on-year. After 2022, we assume a still robust but slightly lower CAGR for RE in the CTS, compared to the CPS.

Hydro and nuclear: In the CTS, the nuclear capacity addition is assumed to occur as per the Government of India policy targets, that is, 16.8 GW at the end of 2027. No further addition beyond 2027 to 2030 is considered in the nuclear power sector. Hydropower capacity addition is assumed to be a bit slower than in the CPS, given the challenges of financing, project execution, and socio-environmental opposition to large hydro projects (see Box 1). The CTS considers a CAGR of 2.6% for large hydro, compared to 3.7% in CPS till 2030. The cumulative capacity would be around 63 GW by 2031, as compared to the present capacity of 45 GW.

HRES

As the name suggests, the HRES assumes a higher RE growth compared to conventional and fossil resources. Thus, the HRES has a comparatively higher CAGR to 2030 (15%) for RE capacity addition, compared to the CPS (13%) and the CTS (12%). This scenario aims to maximize the RE capacity within the total installed capacity, with more than 50% share in the capacity mix by 2030. However, it should be noted that in the HRES, this higher CAGR for RE is 'backloaded' compared to the CPS, occurring more after 2022, compared to the rapid CAGR for RE to meet the 175 GW target by 2022.

Further details for the HRES are as follows:

Coal power: The HRES assumes an addition of 38 GW

Table 7: Capacity assumptions in the HRES

Technology	2018		2022		2027		2030	
	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity	MW	% of Total Capacity
Coal	197172	57%	217283	46%	191711	33%	191711	26%
Gas	24897	7%	24897	5%	24897	4%	24897	3%
Diesel	838	0%	838	0%	838	0%	838	0%
Nuclear	6780	2%	10080	2%	16880	3%	16880	2%
Hydro	45293	13%	53701	11%	64666	11%	70124	10%
Solar	21651	6%	81000	17%	142311	25%	230000	32%
Wind	34046	10%	62132	13%	106687	19%	160000	22%
Small Hydro	4486	1%	6857	1%	8821	2%	10393	1%
Biomass	8839	3%	15029	3%	18136	3%	20621	3%
Total Installed Capacity	344002	100%	471817	100%	574947	100%	725464	100%

Source: TERI assumptions and scenario-building

Table 8: Cumulative CAGR for each technology from FY2018, HRES

Technology	Cumulative CAGR% from FY 2018		
	2022	2027	2030
Coal	2.5%	-0.3%	-0.2%
Gas + Diesel	0.0%	0.0%	0.0%
Nuclear	10.4%	10.7%	7.3%
Hydro	4.3%	4.0%	3.4%
Solar PV + Rooftop	39.1%	23.3%	20%
Wind	16.2%	13.5%	12.6%
Small Hydro	11.2%	7.8%	6.7%
Biomass	14.2%	8.3%	6.7%
Total	8.2%	5.9%	5.9%

Source: TERI assumptions and scenario-building

coal power plants by 2022, and thereafter no further addition of coal power plants. Retirement of around 44 GW of old plants is considered. This results in the net capacity reduction of 6 GW in the coal fleet by 2030. In the HRES, the addition of coal power is restricted to enable an aggressive low-carbon pathway, and to maximize the use of RE technologies in the generation mix. No addition and retirement in gas power stations is considered. However, in the HRES, gas power plants may have to play a role in grid balancing and flexibility and peak requirements: these issues will be studied further in Work Package 3.

Hydropower: A cumulative capacity of 8 GW (at 4% CAGR) is expected to be commissioned in the period 2018–22. Beyond 2022, a similar growth rate (3.8% CAGR) is expected, adding 20 GW of hydro capacity by 2027. The projected hydro capacity by 2030 is 70 GW in the HRES.

Nuclear power: The nuclear capacity addition considered under this scenario is the same as under the CPS, that is, 17 GW by 2027. No capacity addition beyond 2027 is considered in the nuclear power sector, given its inflexibility in a high RE scenario.

RE: A CAGR of 15% to 2030 is considered resulting in more than 50% share of RE in the capacity mix. If the same growth rate continues till 2030, the RE capacity will be 421 GW—58% of the total installed capacity. The non-fossil power capacity would be around 70% in this scenario.

Generation and PLF in Each Scenario

Electricity generation from each technology has been calculated given the following assumptions:

1. All-India grid demand of 2040 TWh by 2030, excluding T&D losses or behind-the-meter consumption, is considered.
2. RE power plant, nuclear, and hydro stations are considered as must-run.
3. Regarding coal power plants, the scheduling of power has been considered as per the merit-order dispatch. For power dispatch, normally coal pithead stations are given priority over non-pithead stations.
4. Ex-bus generation is calculated by considering auxiliary consumption of 7% for coal power plant, 12% for nuclear, 3% for gas, and 1% for hydropower plant.
5. Battery-storage and other energy-storage technologies and their associated conversion losses have not been considered while calculating the electricity generation (see Section 7).
6. As stipulated by the NEP 2005, 5% reserve is to be provided. The requirement of this reserve capacity has been incorporated into the study by reducing the availability of conventional plants by 5%. For example, in the CPS the installed capacity in 2022 would be around 479 GW. Of this, RES will contribute around 175 GW. Therefore, 304 GW may be the likely installed capacity from conventional sources, of which 15 GW has been kept as reserve capacity while conducting the generation and PLF analysis here.
7. A T&D loss of 16% has been considered in 2030 with respect to the present level of 22% in FY2018. Also, the grid-level demand has been computed after taking solar rooftop generation in consideration. So, ex-bus bar generation requirement is net of own rooftop generation.

CPS

The PLF of the coal power capacity of 217 GW will be around 54% in 2022. The PLF is expected to increase up to 55% by 2027 and further increase to 70% by 2030. The increase in coal fleet PLF is primarily because of high demand and limited coal fleet addition. Additionally, the lower capacity utilization factor (CUF) of solar and wind power means they contribute comparatively less in electricity generation to meet the overall demand, requiring a greater contribution from coal to meet the annual generation requirement.

Table 9 lists out the generation and PLF of each technology.

In 2022, the share of variable RE (VRE) in generation will be around 18%, compared to the current level of 8%, and will increase to 24% in 2027 and 25% in 2030. The total share of RE, including large hydro, will be 37% in 2027, increasing to 38% in 2030. The share of zero-carbon sources would be 41% by 2030. Coal would still be the largest single source of generation in 2030, with a 54% share, down from the current 67%. This suggests an overachievement in the CPS of the government's Nationally Determined Contribution (NDC), which is for 40% of the installed capacity to be from non-fossil-fuel sources: in this scenario, 40% of grid-based generation is from non-fossil-fuel sources, an even more significant outcome than implied by the capacity target. There will not be any significant change in the contribution of gas, hydro, and nuclear technology to the total electricity generation across the scenario period. These numbers are represented in Figure 1. The grid emissions factor drops by 19% between 2018 and 2030. Driven by the ambitious short-term target of 175 GW, the CPS scenario is relatively 'frontloaded', the most significant change occurring in the earlier years of the projection.

CTS

Due to comparatively less RE addition in the CTS, coal plants provide the majority of electricity generation required to meet the demand. The contribution of electricity generation by coal power plants to the total

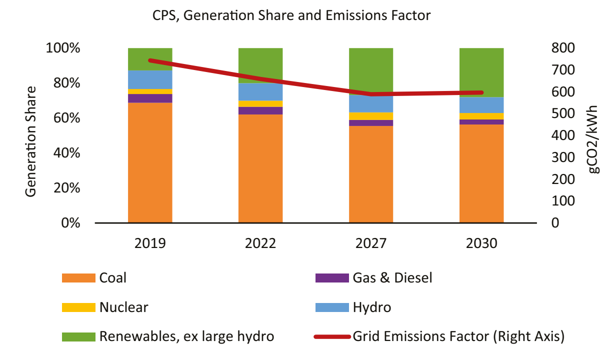


Figure 1: Technology shares in generation and grid emissions factor, CPS
Source: TERI assumptions and scenario-building

Table 9: Generation and PLF, CPS

	2022		2027		2030	
	Generation Ex PP. (TWh)	PLF%	Generation Ex PP. (TWh)	PLF%	Generation Ex PP. (TWh)	PLF%
Coal	956	54	1073	55	1365	70
Gas	68	30	68	30	68	30
Nuclear	54	70	85	70	91	70
Hydro	155	35	190	35	220	35
Solar	119	19	208	19	275	19
Wind	124	25	210	25	280	25
Small Hydro	15	35	24	35	31	35
Biomass	27	35	44	35	59	35
Total Generation Ex PP, Ex rooftop solar	1518	-	1901	-	2389	-

Source: TERI assumptions and scenario-building

electricity generation will be 63% with the PLF of 59% in 2022, and 61% in 2030 with a PLF of 73%. Due to lower growth of the RE capacity, compared to the CPS and the HRES, the PLF of coal power plants will increase in the later forecast years, offset somewhat by the addition of further coal capacities. There will not be any significant change in the contribution of gas, hydro, and nuclear technology to the total electricity generation year-on-year. The VRE share would be 15% in 2022, rising to 22% in 2030. The total zero-carbon share would be 35% by 2030. The grid emissions factor would decline by 10% between 2018 and 2030.

HRES

In the HRES, high penetration of RE and lower thermal power capacity result in higher overall PLF of the coal fleet. This is because of: i) relatively rapid growth in demand, ii) lower CUF of renewable technology, and iii) absence of any coal capacity additions. Thus, to meet the growth in generation requirement the coal PLF must rise, particularly in the later part of the forecast period, to levels which are unlikely to be feasible, given forced and unforced outages. A response to this may be that additional RE capacity should be added, in order to lower the coal PLF to more feasible levels. However, the HRES already requires a significant degree of flexibility in the system, in terms of hourly, daily, monthly, and seasonal balancing of supply and demand (see Section 7). This may constrain the addition of further RE capacity beyond what is seen in the HRES.

In 2030, the contribution of electricity generation from coal power plants is about 50% (less than that of the CPS and the CTS) to the total electricity generation with the corresponding capacity share of 26% in the total capacity mix. This results in higher capacity utilization of thermal power plants, as noted previously. In 2030, the contribution of VRE generation to the total electricity

Table 10: Generation and PLF, CTS

Generation Ex. PP (TWh)	2022		2027		2030	
	Generation Ex PP. (TWh)	PLF%	Generation Ex PP. (TWh)	PLF%	Generation Ex PP. (TWh)	PLF%
Coal	1005	59	1171	63	1527	73
Gas	68	30	68	30	68	30
Nuclear	54	70	85	70	91	70
Hydro	154	35	189	35	193	35
Solar	98	19	176	19	236	19
Wind	124	25	200	25	262	25
Small Hydro	15	35	15	35	15	35
Biomass	27	35	27	35	27	35
Total Generation Ex PP, Ex Rooftop Solar	1545	-	1931	-	2418	-

Source: TERI assumptions and scenario-building

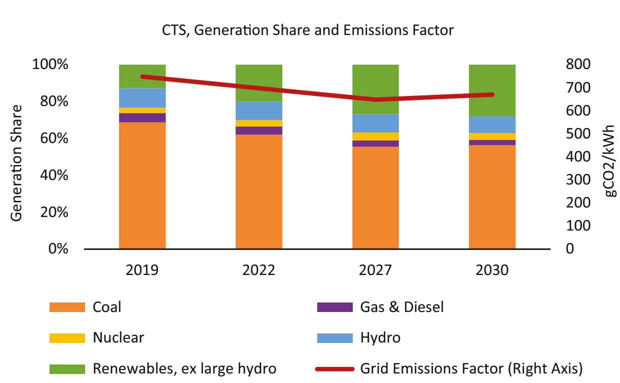


Figure 2: Technology shares in generation and grid emissions factor, CTS
Source: TERI assumptions and scenario-building

generation will be around 29%, while the zero-carbon share would be 45%. The contribution of gas, nuclear, and hydropower to the total energy generation does not vary significantly from 2022 to 2030. The grid emissions factor drops by 25% by 2030.

Table 11: Generation and PLF, HRES

Generation Ex. PP (TWh)	FY2022		FY2027		FY2031	
	Generation Ex PP. (TWh)	PLF %	Generation Ex PP. (TWh)	PLF %	Generation Ex PP. (TWh)	PLF %
Coal	950	54	1064	66	1269	81
Gas	68	30	68	30	68	30
Nuclear	54	70	85	70	91	70
Hydro	161	35	196	35	213	35
Solar	94	19	193	19	327	19
Wind	129	25	222	25	334	25
Small Hydro	21	36	26	35	31	35
Biomass	40	35	48	35	55	35
Total Generation Ex PP.	1517	-	1901		2389	-

Source: TERI assumptions and scenario-building

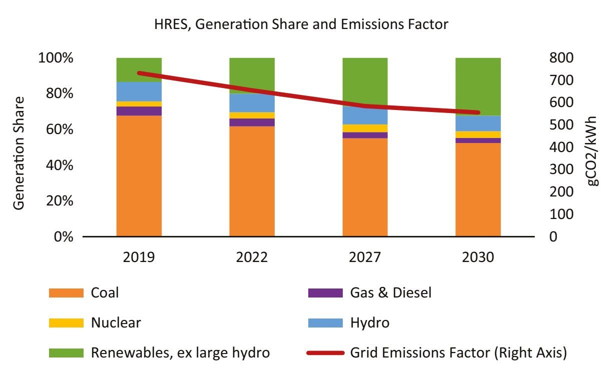


Figure 3: Technology shares in generation and grid emissions factor, HRES
Source: TERI assumptions and scenario-building

Investment Requirement, LCOE, and System Costs

Investment Requirement

Table 12 shows the total capital investment required in each scenario in order to finance the additional production capacities between 2018 and 2030. The following assumptions were made:

- For new coal capacity addition, a capital cost of Rs 6.8 Cr/MW is considered. This includes the cost of pollution-control equipment (such as flue-gas desulfurization [FGD] and selective catalytic reduction [SCR]) required to comply with the new environmental norms.
- The capital cost per MW for hydro and nuclear is considered as per the Central Electricity Regulatory Commission's (CERC) norms.
- A reduction of 3% per year till 2024, 2% from 2024 to 2027, and 1% after 2027 is considered in the capital cost of solar PV technology. The reduction in the capital cost is considered due to technological improvement and optimized manufacturing processes. For wind, a moderate annual rate of decline in capital costs of 1% per year is considered.
- The capital cost described below does not include any transmission or distribution system cost.

It can be seen that the CPS requires the most capital investment, whereas the CTS and the HRES are roughly comparable, with the higher capital expenditure on RE in the HRES being offset by lower capital expenditure on coal, and vice-versa in the CTS. The CPS requires the most capital expenditure because it is the scenario with the most capacity (709 GW in 2031). It should be clearly noted that the aforementioned capital expenditure figures are without considering the additional investment required for system flexibility and balancing. For example, the very high PLF for coal in the HRES, required to meet the

Table 12: Cumulative capital investment required in the different scenarios

Capital Investment Required till 2030 (in Rs Lakh Cr)	CPS	CTS	HRES
Solar	5.19	3.94	6.22
Wind	3.77	3.44	4.79
Small Hydro	0.32	0.04	0.38
Biomass	0.77	0.06	0.66
Hydro	3.31	2.12	2.98
Nuclear	1.62	1.62	1.62
Coal (new capacity)	5.76	7.40	2.60
Total Capital Investment	20.74	18.61	19.24

Source: TERI assumptions and scenario-building

annual electricity demand, may be considered unfeasible in view of plant availability factors, and the daily cycling of coal required to balance the VRE. In this case additional investments in flexible resources may be required, which would raise the investment requirement of the scenario in question. By contrast, this additional investment may be lesser in the CPS, because the dispatchable capacity is already higher in this scenario. These issues are investigated further in Section 8.

A crucial conclusion emerging from this analysis is that scenarios able to meet the annual energy requirement show broadly comparable capital investment needs, whether they are based on higher or lower shares of coal or RE. Critically, therefore, the incremental investment costs of a high RE pathway, if there are any, will not be from the higher costs of RE electricity itself, but rather from the investments required to balance its intermittency and non-dispatchability. Studying the costs of system flexibility is, therefore, the need of the hour.

LCOE

In the course of seven years, competitive bidding in RE has dropped the solar (ground-mounted PV) tariff from 9–10 R/kWh to 3.00–2.50 R/kWh. The main reasons for this reduction in tariff are competitive reverse-auction bidding, supportive and de-risking policies, and the availability of lower-cost concessional and international financing. In this section, we analyse the projected LCOE for different technologies. It should be noted that we attempt to tailor assumptions to broadly reflect the all-India scenario, and thus the CUFs taken for RE technologies reflect assumptions on the average resource quality across India. As with the earlier assessment of the generation profiles in each scenario (Table 9, Table 10, and Table 11), we have made the conservative assumption that the CUF for wind and solar does not improve across the projection period.

Framework

To estimate the LCOE of different technologies, the standard LCOE formula is used, which differs from the CERC method of calculating real-time tariff. The main difference between the two methodologies is that in the LCOE methodology, financing costs are not included in the cash flow but rather reflected in the discount rate calculated according to the weighted average cost of capital (WACC); and in the LCOE model both cash flows (the numerator) and the annual energy production (the denominator) are discounted by the WACC. The LCOE analysis can be considered the annualized tariff required to meet the equity internal rate of return (IRR) implied in the WACC.

Common parameters include a pre-tax WACC of 12%, consistent with a 70:30 debt equity split at the prevailing rates of ca. 11% and 15%, respectively. A corporate tax rate of 33% has been considered, and straight-line depreciation. For variable costs, the annual fuel-related outgoings have been calculated considering technology-specific heat rates and fuel prices translated into R/MMbtu according to the prevailing India-specific calorific values. A distinction is made between pithead and non-pithead plants in calculating fuel costs, although the same escalation rate is (conservatively) applied to both pithead and non-pithead fuel costs. For natural gas plants, we assume a 75–25% pooled domestic gas and imported LNG, which may be considered as optimistic. Fuel-price escalation has been considered at 4.0% per year for both coal and gas, which is substantially lower than the observed increase over the last 5–10 years, where, for example, nominal coal prices have grown by around 3.6 percentage points above inflation. A major driver of this has been increased transport costs, as well as 'one-off' items such as increases in taxes and duties, including the clean energy/GST compensation cess at 400 R/ton. For solar, a starting capital cost of 3.50 Cr/MW has been taken, which can be considered as quite aggressive, and may vary in particular with land- acquisition costs.

Results

Table 13 displays the key results from the analysis.

From Table 13, it can be seen that new renewables (wind and solar) are calculated to be the cheapest source of incremental generation. They are also cheaper than the marginal cost of between ¼ and ½ of the existing coal fleet, which has a variable tariff in the range of 2.50 to 3.00 R/kWh. Coal is projected to lose competitiveness across the projection period, due to its rising cost and the increased capital cost. As noted earlier, we have been conservative regarding the projected fuel-price escalation. If one is less bullish on cost improvements for RE, the picture of relative prices still doesn't change too much Assuming 20% higher than the projected capital costs in 2030 would increase the solar LCOE to 2.70 R/kWh, which is still lower than the competing generation technologies. Box 2 discusses some of the uncertainties around the costs of coal and solar.

Box 2: Uncertainties in the costs of coal and solar

As mentioned earlier, we took a starting capital cost of 3.5 Cr/MW for solar. This can be considered aggressive, with capital costs only recently dropping below 4.0 Cr/MW. Table 14 displays the sensitivity of calculated LCOE to capital costs and financing costs (WACC). It can be seen that if one assumes a 4.00 Cr/

Table 13: Modelled LCOE of different supply technologies (R/kWh)

Results					Summary of Key Assumptions		
	2017	2022	2025	2030	Starting Investment Cost (R Cr/MW)	Capital Cost Learning Rate (%/yr)	Fuel-Price Escalation (%/yr)
Solar PV Ground-Mounted	2.87	2.58	2.42	2.30	3.50	-2.10%	n/a
Wind Onshore	2.85	2.75	2.69	2.58	4.50	-1.00%	n/a
Solar PV Rooftop	6.76	6.03	5.64	5.34	6.50	-2.10%	n/a
Small Hydro	3.88	3.88	3.88	3.88	5.04	n/a	n/a
Biomass Power	5.68	6.58	7.39	9.02	5.59	n/a	5.00%
Nuclear	3.92	3.93	3.96	4.02	18.02*	n/a	2.00%
Large Hydro	4.81	4.81	4.81	4.81	12.00	n/a	n/a
Natural Gas Combined Cycle#	5.10	5.71	6.24	7.26	4.20	n/a	4.00%
Pithead Super Critical Coal	3.64	3.97	4.26	4.82	6.80	n/a	4.00%
Non-Pithead Super Critical Coal	4.97	5.53	6.01	6.95	6.80	n/a	4.00%

*Includes insurance and decommissioning
Costs of gas-based generation are assuming a 75–25% split between pooled domestic gas and LNG.
N.B. The above calculations use the accepted formula for calculating the LCOE (required tariff to meet equity rate of return), not the CERC tariff formula. Common across all technologies is the assumption of 12% WACC, 33% corporate tax rate, and straight-line depreciation.
Source: TERI analysis and modelling

MW investment cost, then the WACC would need to be relatively low (ca. 10%) to drive the LCOE below 3 R/kWh. In the midterm, there is no doubt, however, that solar capital costs will continue to decline: the analysis here doesn't fundamentally change the picture of relative competitiveness of technologies in the midterm.

Table 14: Sensitivity of 2018 ground-mounted solar PV LCOE to capital costs and WACC (R/kWh)

		WACC (%)					
		14%	13%	12%	11%	10%	9%
Capital Cost (Cr/MW)	4.5	4.0	3.8	3.6	3.4	3.2	3.0
	4.25	3.8	3.6	3.4	3.2	3.0	2.8
	4.00	3.6	3.4	3.2	3.0	2.9	2.7
	3.75	3.4	3.2	3.1	2.9	2.7	2.5
	3.50	3.2	3.0	2.9	2.7	2.5	2.4
	3.25	3.0	2.8	2.7	2.5	2.4	2.2
	3.00	2.8	2.6	2.5	2.4	2.2	2.1

Source: TERI analysis and modelling

As noted earlier, between 2006 and 2016, the price index for non-coking coal grew by 8.5% per year, compared to the all-commodity WPI growth of 4.90%. Nonetheless, we took a modest 4.0% per year escalation of the coal price for both pithead and non-pithead plants. Earlier, we took 6.8 Cr/MW for new super-critical plants, in view of the additional cost of super-critical technology and the required pollution abatement technology. This is somewhat above the inflation-adjusted value, including on average about 30% cost overruns, of the last 10 years of projects, at 6.3 Cr/MW. The higher value of 6.8 Cr/MW reflects the additional costs of more efficient technologies as well as pollution abatement technologies. Table 15 displays a sensitivity analysis on these two parameters. One can see that the LCOE of non-pithead coal is highly sensitive to assumptions of the coal-price escalation factor, and less so to the initial capital cost.

The sensitivity analyses (Table 15), thus, don't fundamentally change the picture regarding the relative competitiveness of different generation technologies, on an LCOE basis.

Table 15: Sensitivity of 2018 non-pithead super-critical cost to capital costs and coal-price escalation (R/kWh)

		Capital Cost (Cr/MW)				
		6.0	6.2	6.4	6.6	6.8
Coal Price Escalation (%/year)	2%	4.29	4.32	4.35	4.38	4.42
	3%	4.55	4.58	4.62	4.65	4.68
	4%	4.87	4.90	4.93	4.97	5.00
	5%	5.24	5.28	5.31	5.34	5.37
	6%	5.69	5.73	5.76	5.79	5.82
	7%	6.24	6.27	6.30	6.34	6.37

Source: TERI analysis and modelling

It should be noted that care needs to be taken in comparing the LCOE of different technologies. Variable renewables will have grid-integration costs that are not reflected in the LCOE, such as balancing, profile, and transmission costs. Fossil-fuel-based technologies will have significant environmental externalities related to climate change and local air pollution. Thus, the LCOE comparison gives only one perspective on the relative competitiveness of different technologies, and needs to be complemented with (more challenging) analysis of grid integration and societal costs (see Section 7).

System Costs

In this section we make a calculation of the system costs of electricity supply in the three scenarios. One should be clear about what is included in the boundary of system costs, and what is not. Here we define system costs as the ex-bus bar cost of procurement of the electricity supplied to the system. It, thus, excludes transmission and distribution costs, as well as the costs of providing system flexibility which may be needed to integrate a high share of RE (such as investments in demand response, battery storage, or additional flexible capacity). These issues are addressed further in Sections 7 and 8. Before considering the additional system requirements for flexibility, and their potential cost, we consider it instructive to look first at the issue of system costs without flexibility, and then add an estimation of these costs back in as a second step. This makes the additional cost of flexibility an explicit parameter for consideration.

System costs here can, therefore, be considered as the ex PP. system-wide tariff, including all variable and fixed costs. The tariff is calculated in each year according to the capacity and generation numbers given in the earlier tables. A stylized merit order is used to calculate the annual generation from the thermal fleet, with higher-cost non-pithead and natural gas plants operating at a lower PLF.

Table 16: Ex-bus bar system costs (R/kWh)

Scenario	2022	2027	2030
CPS	5.47	5.60	5.55
CTS	5.36	5.50	5.50
HRES	5.46	5.49	5.40

Source: TERI analysis and modelling

Several observations can be made with regard to the data in Table 16. The HRES has a slightly lower system tariff in the early part of the projection period, compared to the CPS. This is because of the slightly less procurement of RE, compared to the CPS, which prioritizes meeting the 175 GW target. Of all the scenarios, the lowest system tariff in the early period is seen in the CTS, due to the higher CUF of existing capacities and lower additional investment costs. However, the deflationary impacts of RE can be seen most strongly after the early 2020s, when the system tariff of the HRES scenario starts to fall below those of the other scenarios, as the required incremental capacities come from cheaper RE, notably wind and solar. By 2030, the HRES has the lowest system tariff by some margin.

While stylized, the aforementioned analysis is logically coherent. In the short term, driving the strong uptake of RE requires investment and lowers, all other things being equal, the CUF of the existing capital stock. This would tend to raise per-unit system costs, except where RE were to replace utilization of capacities with higher variable costs, for which there is a substantial opportunity in the case of higher variable cost coal. However, this opportunity is also constrained by the requirement for these capacities to contribute to meeting the annual energy requirement, assuming supply-side or grid-integration constraints on the rate at which RE can be expanded. However, driving RE earlier lays the foundation for a high RE power system, which, according to the aforementioned analysis, could have a cheaper system cost in the midterm.

As noted, we calculate system tariffs without considering the additional investments that may be required to ensure system stability under a regime of high RE. This is the issue to which we now turn.

Initial Flexibility 'Stress Test'

In the aforementioned analysis, the total annual demand can be met through the installed capacities of the different scenarios (although under the HRES, the annual PLF of the coal fleet reaches potentially unfeasibly high levels by 2030). However, the intraday and seasonal balancing of RE are going to be major challenges and require additional analysis. This balancing raises the need for flexibility in system operation, and may require investment in different flexibility options on both the demand and supply sides, in addition to the scenarios' production capacities described in the earlier sections.

In this section we conduct an initial flexibility 'stress test' in order to bring this issue of system balancing to the fore when thinking about the characteristics of different potential supply scenarios to 2030. The methodological approach is as follows:

- The analysis is conducted on an all-India level for 2030, assuming away any potential intrastate or interstate transmission-system bottlenecks. **A spatially explicit analysis of grid balancing and system operation will be conducted in the dispatch modelling of NREL in WP3 of this project. For the moment, we explore the flexibility challenge of our scenarios on an all-India basis.**
- The hourly gross load profile for all-India was analysed for the past 10 years to see how the load profile is changing. A gross load profile was developed taking the most recent load profile from POSOCO (FY2017–18), and scaling it to cover the annual demand in 2030. The load profile was adjusted to reflect the estimated system load factor of the 19th EPS for 2030, which is projected to decline somewhat, reflecting the increasing 'peakiness' of demand.
- A simple model of system operation was constructed with the following assumptions: i) wind and solar are

treated as must-run; ii) nuclear, biomass, small hydro, and pithead coal are assumed to run essentially as baseload according to their respective PLFs (pithead coal, because of its cost advantage, receives full schedule), or seasonal production profiles in the case of hydro; iii) gas, pondage hydro, and pumped hydro are assumed to operate as highly flexible capacities for load-following and peaking; and iv) non-pithead coal is assumed to be available for flexing down to a technical minimum of 55%.

- Hourly wind and solar production profiles are generated for 2030 from the System Advisory Model as used in the Greening the Grid study.
- Beyond the aforementioned flexibilities, the model does not assume any other flexibility options (such as battery storage; demand response; or additional, flexible dispatchable capacities). The objective is to show initially a 'business-as-usual' scenario for flexibility, without assuming the availability of additional flexibility resources beyond what is currently in the system and projected to be in the system in planning documents such as the NEP. These additional flexibilities are studied in WP3.

The following sections presents the results across three different indicators:

- A set of graphs present the system operation in three days (max demand, average demand, and minimum demand) in three seasons (summer, monsoon, and winter). These graphs also show, on the right axis, the theoretical residual PLF of the coal fleet, assuming that coal PLF can perfectly adjust to meet the residual demand once the aforementioned flexibility options have been exhausted. Of course, the coal fleet cannot adjust 'perfectly' to meet the residual load, but presenting such an assumption allows one to visualize the potential challenges in the grid integration of RE in the scenarios assessed.
- A graph shows hourly energy surplus or deficit across every hour of 2030. The x-axis (horizontal axis) shows the hour of the day, while the y-axis (vertical) shows the energy deficit or surplus in MW. Two different kinds of data points are presented. Transparent grey dots represent each hourly occurrence throughout the year, while red dots represent the average hourly occurrence. An energy-supply surplus (negative value on the y-axis) means that excess energy is being generated with the non-pithead coal fleet operating at its technical minimum. Of course, it is possible to switch off and back on parts of the non-pithead coal fleet, but the long start-up time of coal plants (8–10 hours) makes scheduling turnoff, start-up, and ramping challenging. Also, frequent shut-off and start-up will reduce the plant life and may result in high O&M cost. In a situation of energy surplus, RE curtailment, storage charging, demand response, or turndown of the coal fleet below the technical minimum would be required. An energy deficit (positive value on the y-axis) indicates that even with all plants operating at the maximum possible PLF, the energy generated is not sufficient to meet the hourly demand. In this instance, storage discharging, demand response, or additional capacities would be required.

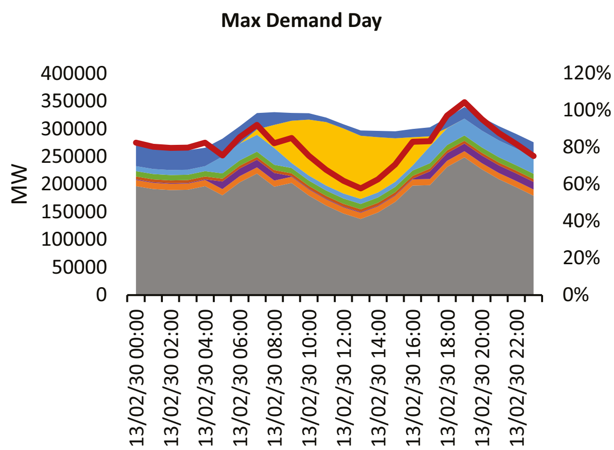
The following sections present the aforementioned three elements of analysis for each scenario without commentary, after which follows a discussion on the results.

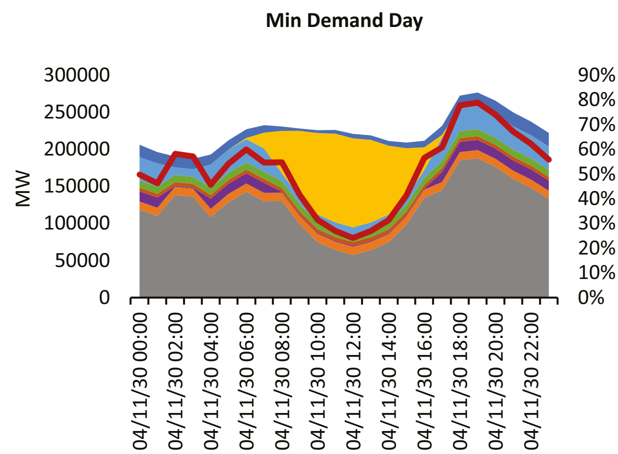
It should be noted again that the analysis that follows presents a BAU scenario in terms of system flexibility, assuming that additional system flexibility has not been significantly developed (for example, lower minimum generation across a significant portion of the coal fleet, storage, demand response, and additional dispatchable capacity). In reality this is neither likely nor desirable: the analysis presents such a scenario in order to more clearly highlight the need for additional flexibilities beyond what exists today.

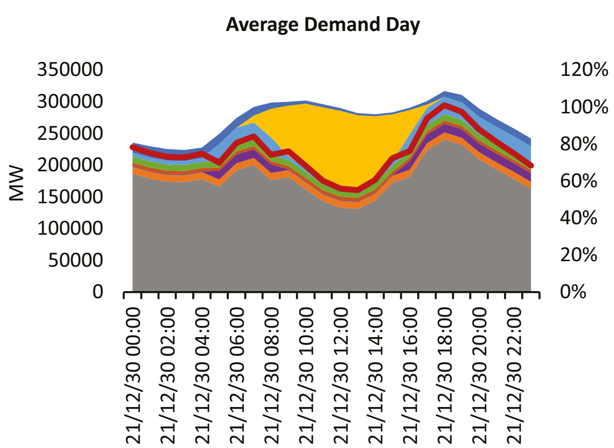
CPS

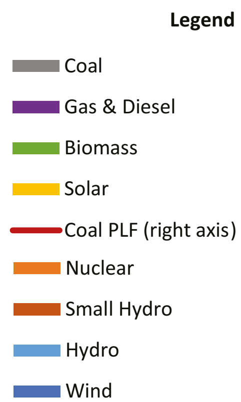
Results

A. Winter Season

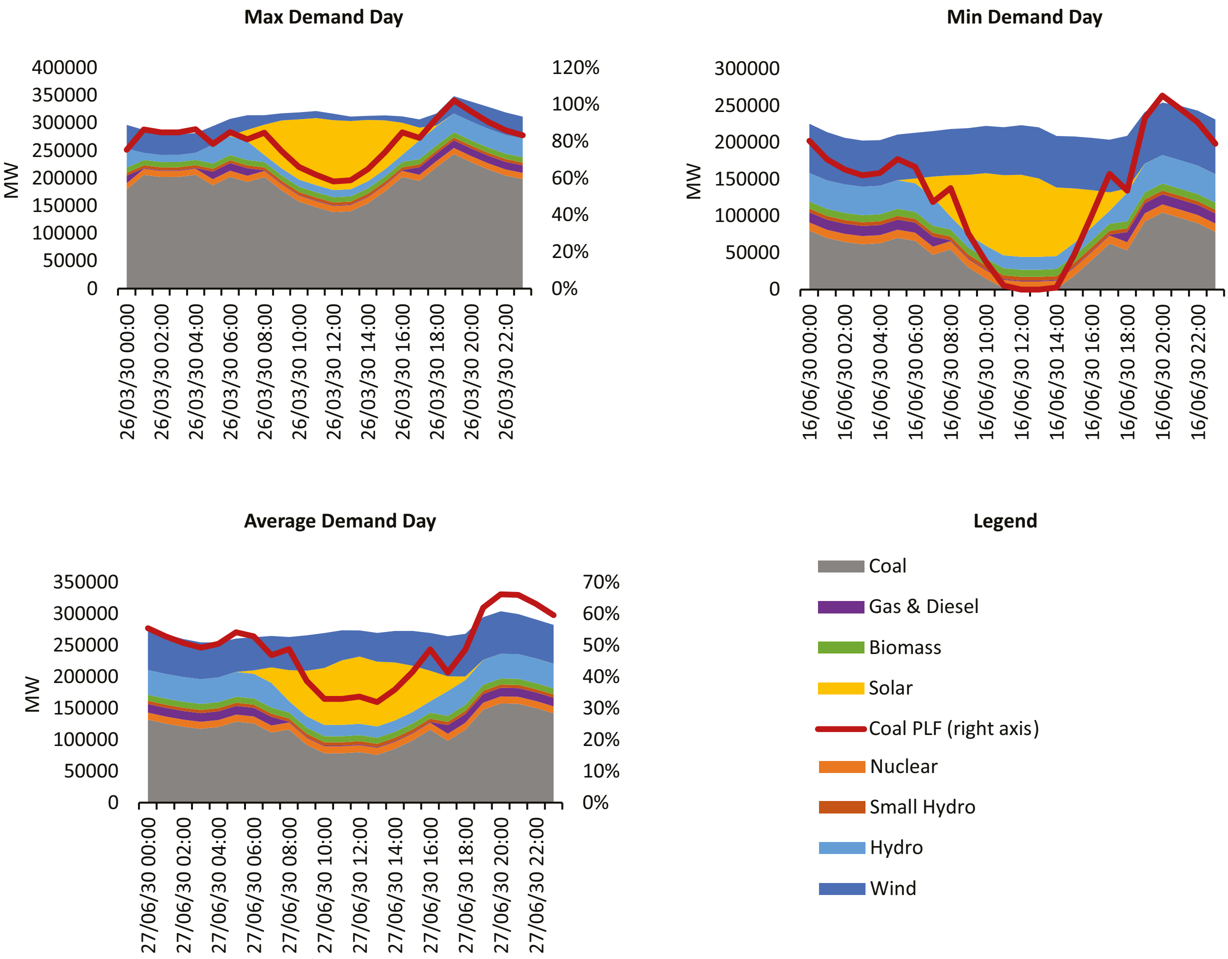








B. Summer Season



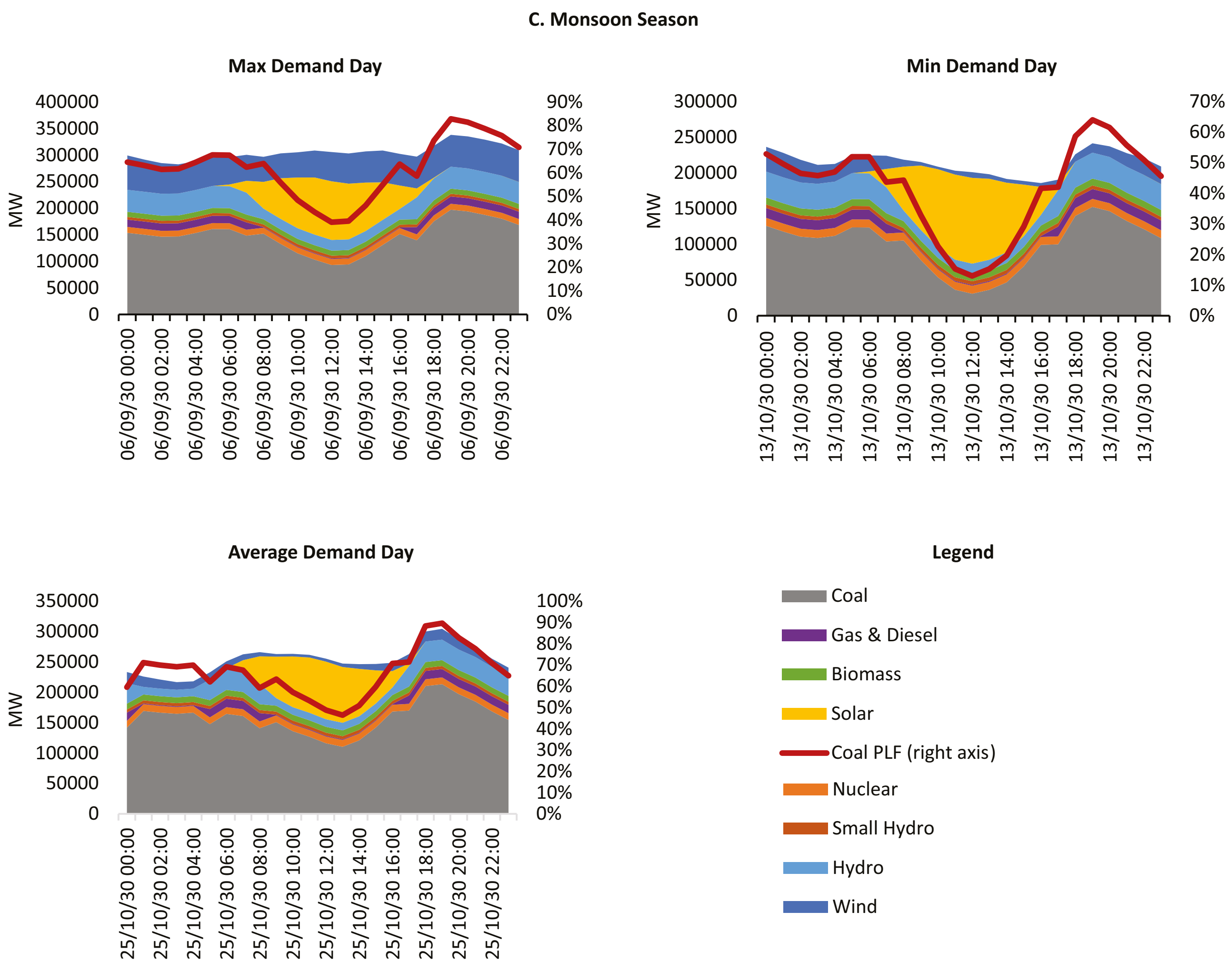


Figure 4: Daily production profile for each technology, 2030, CPS

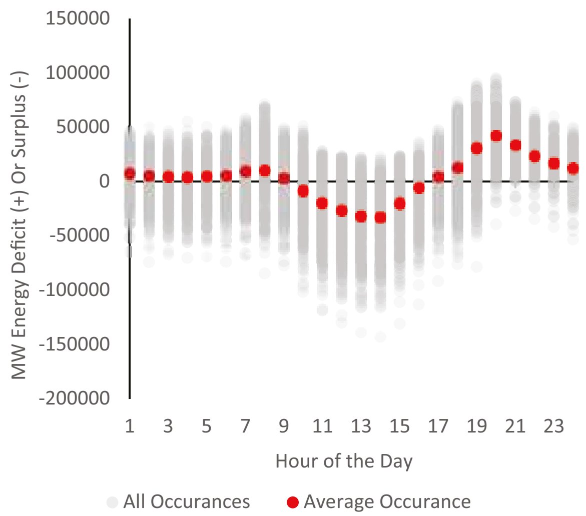


Figure 5: Scatterplot of daily energy surplus or energy deficit, 2030, CPS
Source: TERI analysis and modelling

Discussion

The earlier charts have provided a snapshot of some of the flexibility challenges associated with the CPS. Several aspects are worthy of note.

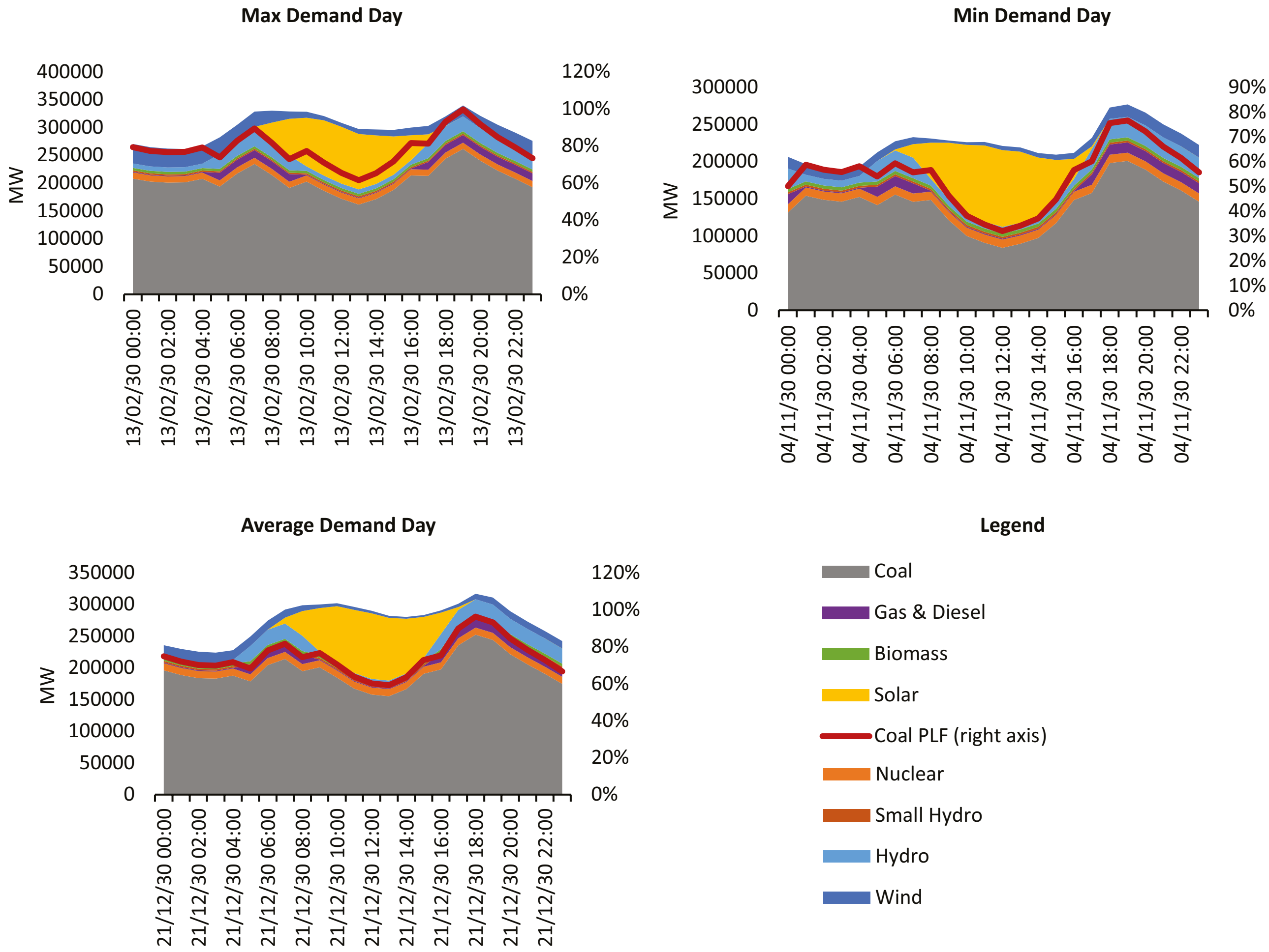
- Deficit of dispatchable resources: Figure 5 shows that on average throughout the year, there is a deficit of resources to meet the evening peak. While on average this deficit is relatively small, it can be significant on some days, reaching a maximum value of about 68 GW on one day. Another way of looking at this is presented in Figure 4: during occurrences when the PLF of the coal fleet needs to exceed 75–80% to meet the residual load during certain times of the day. This is particularly noticeable during a high-demand day during the winter season, when output from wind and hydro is low.
- Excess energy generation: Figure 5 shows that on average throughout the year there is an excess of energy production during midday (in the absence of further backing down of the coal fleet, demand response, storage, or curtailment). On occasion, this surplus of energy generation can be very significant, in the order of 70–100 GW. Another way of looking at this is shown in Figure 4: during low-demand days across all three seasons, the PLF of the coal fleet needs to be well below the current technical minimum (55%). For example, on an average day during the summer season, the PLF of the entire coal fleet would need to reach 40% before ramping up to about 65% to meet the evening peak. This effectively means that a portion of the fleet would probably need to be shut down, potentially on a seasonal basis.
- Seasonal energy balancing: Figure 4 also shows the challenges associated with seasonal energy balancing. In winter, the PLF of the coal fleet is relatively high on an average day, averaging around 63% and reaching highs of around 73%. This is because energy output from wind and, to a lesser degree, hydro is lower during this season, which is not fully compensated for by lower demand. By contrast, during the monsoon months when the output of wind and hydro are high, the PLF of coal is relatively low.

The bottom line of the aforementioned analysis is that even under a baseline 'CPS', based on a large degree on the NEP, the flexibility challenges are significant. Additional flexibility options, beyond what we could expect in a continuation of current trends, would need to be available to ensure the techno-economic feasibility of this scenario.

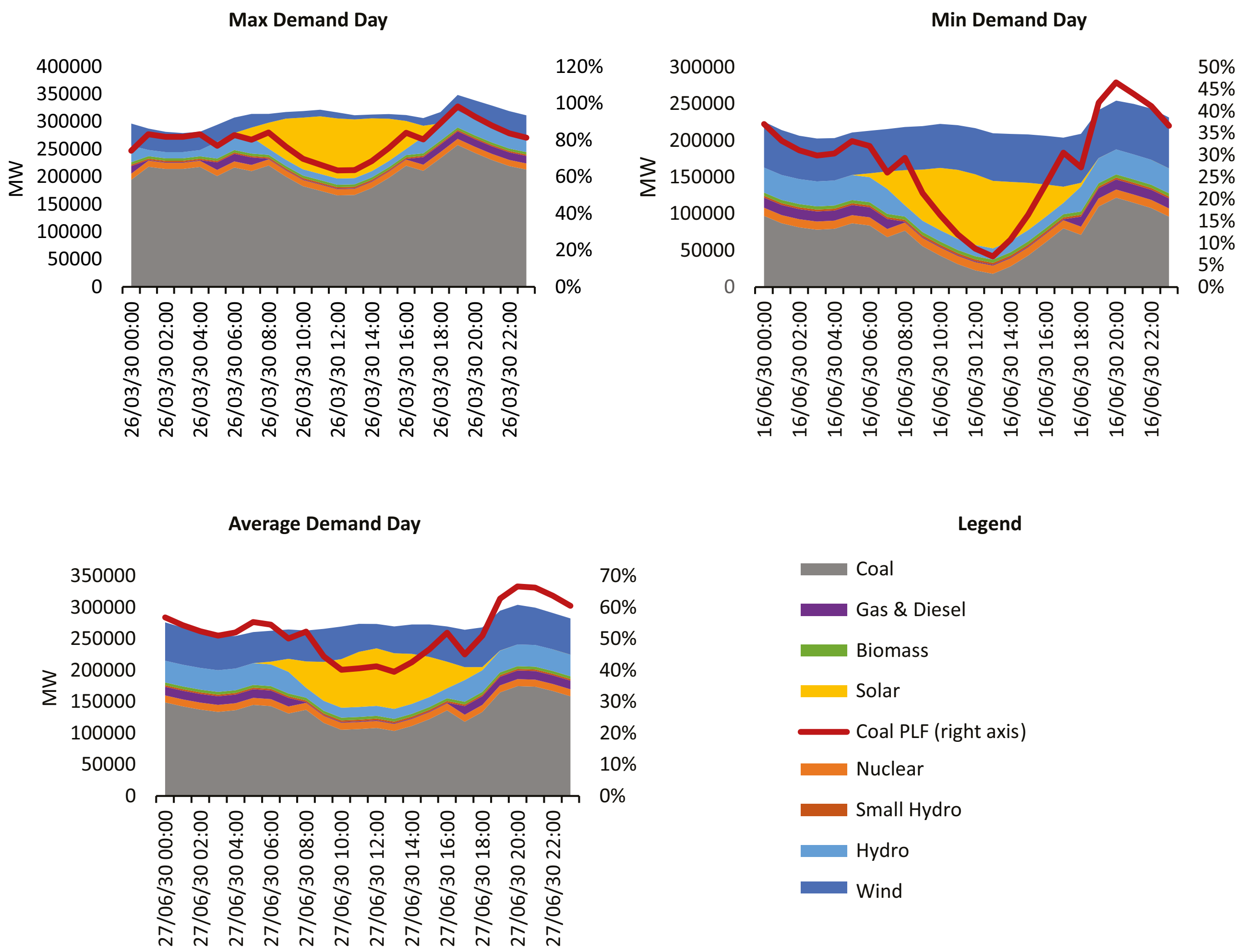
CTS

Results

A. Winter Season



B. Summer Season



C. Monsoon Season

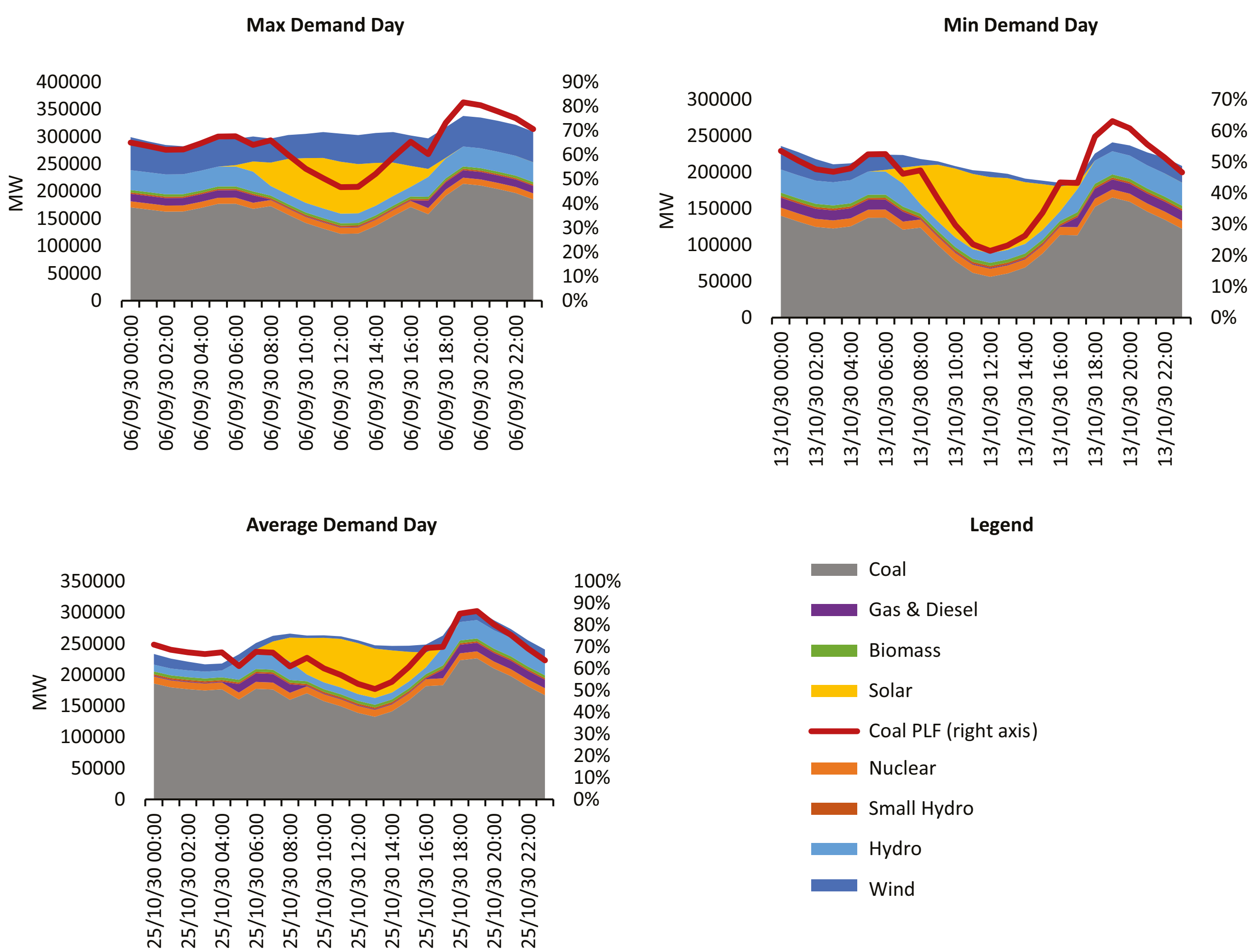


Figure 6: Daily production profile for each technology, 2030, CTS

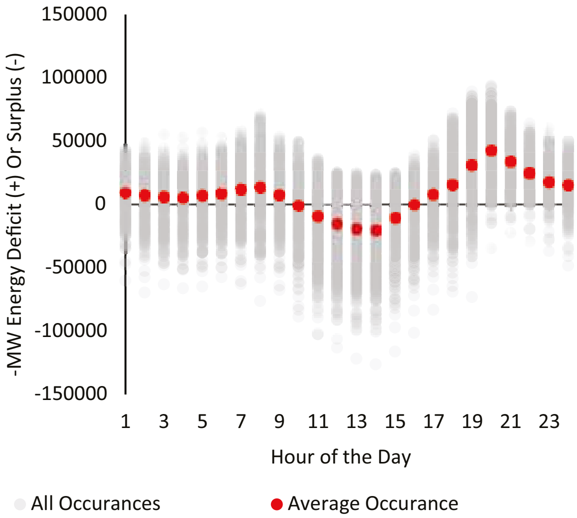


Figure 7: Scatterplot of daily energy surplus or energy deficit, 2030, CTS
Source: TERI analysis and modelling

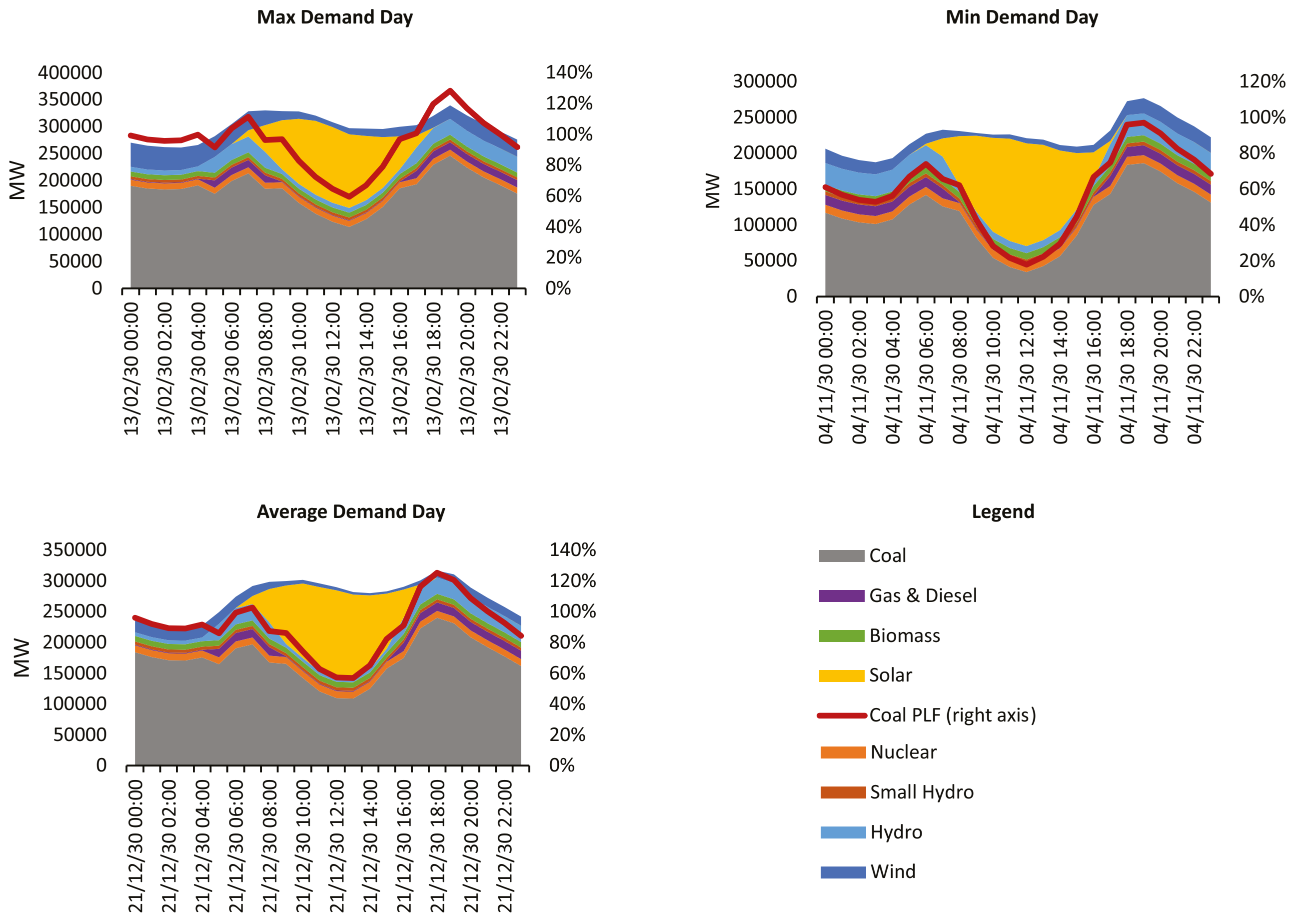
Discussion <Level C>

Generally speaking, the flexibility challenges highlighted in the CPS hold also for the CTS. The main difference is that situations of energy deficit/excessive coal PLF are somewhat reduced due to the additional coal capacity in the system. The flipside of this is that situations of lower coal PLF and switching off of the coal fleet are exacerbated. This highlights a point discussed further below: additional capacities built to meet demand during times of low RE output lower the capacity factor of the fleet relative to a scenario in which RE was completely dispatchable—this raises per unit costs. It is noteworthy that even with 24 GW of additional coal in the CTS versus the CPS, and around 66 GW less RE, there are still considerable flexibility challenges in the CTS.

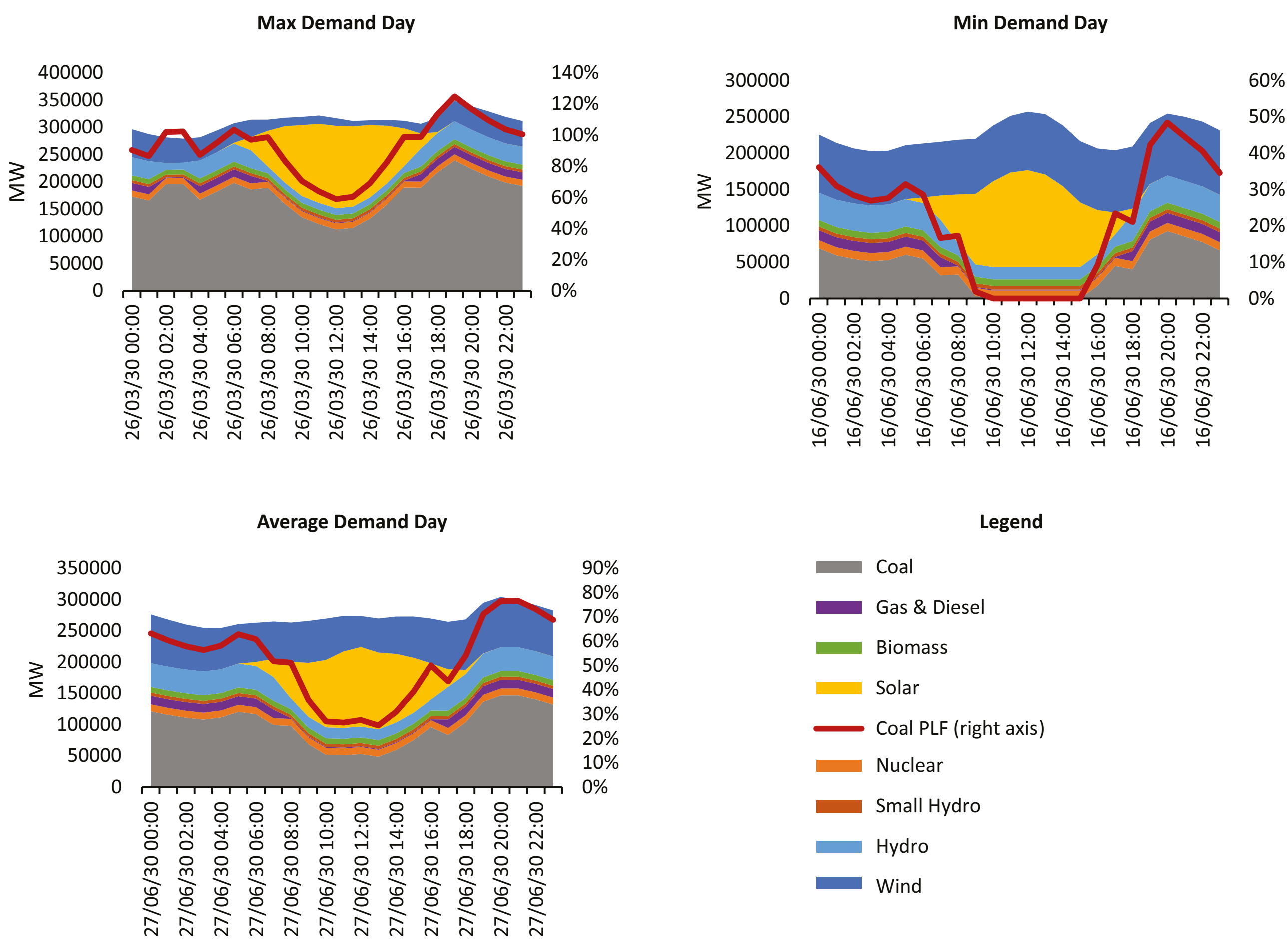
HRES

Results

A. Winter Season



B. Summer Season



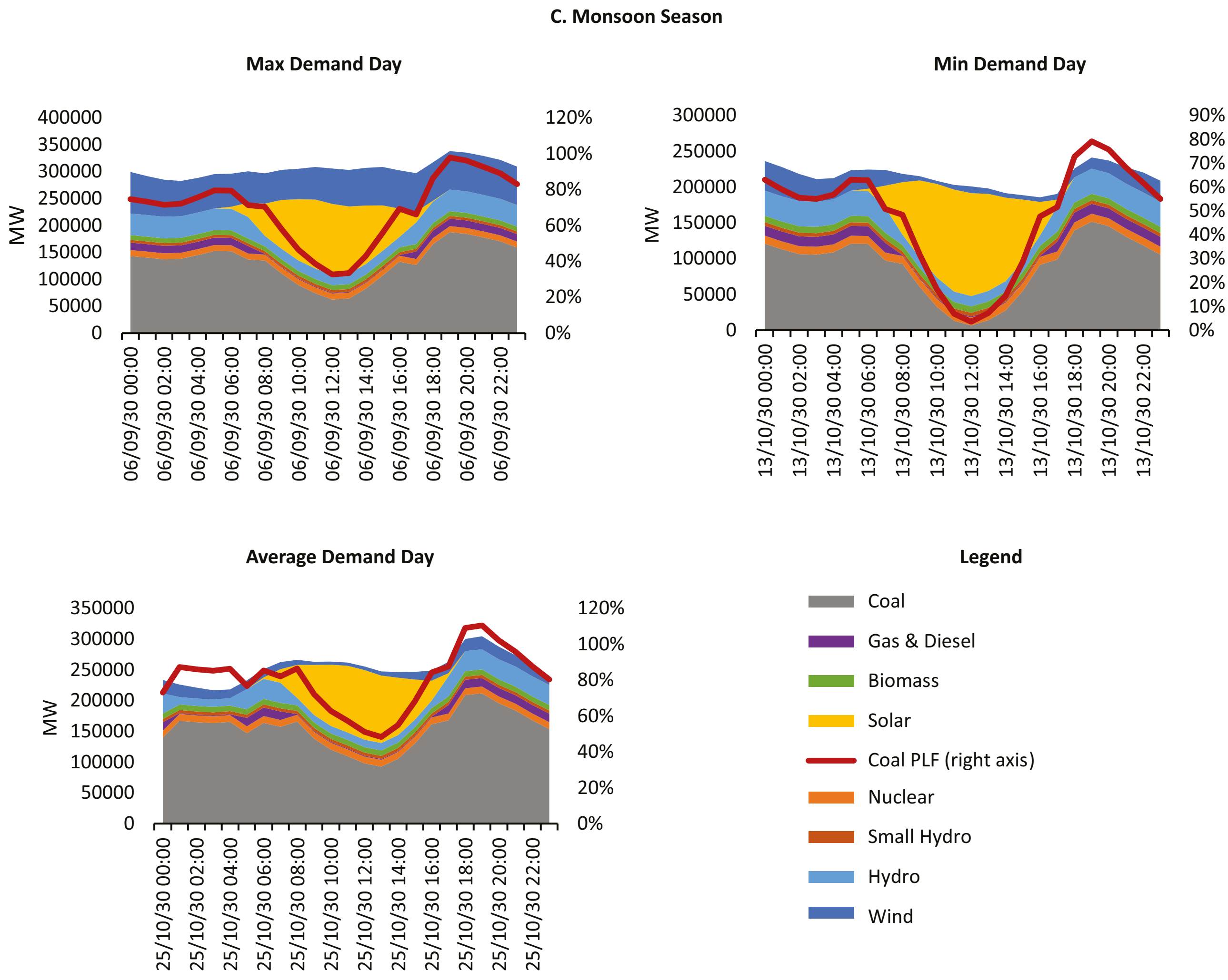


Figure 8: Daily production profile for each technology, 2030, HRES

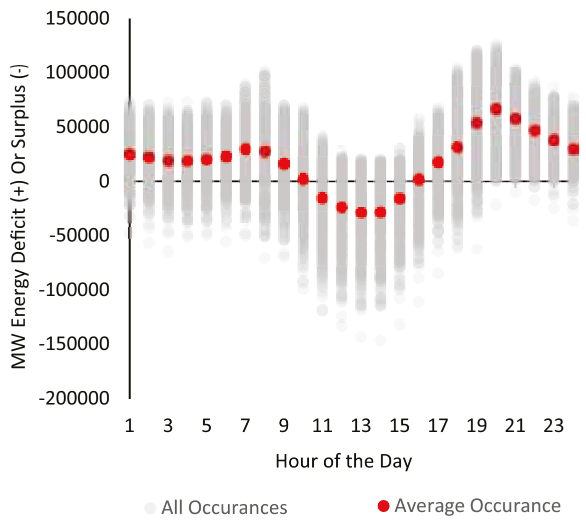


Figure 9: Scatterplot of daily energy surplus or energy deficit, 2030, HRES
Source: TERI analysis and modelling

Discussion

The analysis presented in the earlier figures gives an insight into the scale of the challenge of RE integration in the HRES. The general characteristics of the flexibility challenges remain the same as in the CPS and CTS scenarios, but their magnitude is increased. Panels in Figure 8 where the PLF of the coal fleet rises above 100% indicate situations of energy deficit; it can also be seen in Figure 9 that on average the energy deficit in the HRES is in the order of 40 GW during the evening hours, whereas it reaches in the order of 100 GW during periods of high demand/low RE output. On the other hand, the situation of energy surplus is also sizeable and structural: it averages in the order of 25 GW during the morning solar peak, and can reach levels of up to 130 GW during periods of low demand and high output of other must-run renewables.

The analysis shows that very significant efforts would need to be made to bring to bear the requisite flexibility to make such a scenario feasible. Particular priorities would be:

- Demand response/demand-side management and storage to smooth the daily cycle of solar energy production.
- Additional dispatchable capacities to meet the residual load during times of low RE output and high demand.
- A sizeable programme of seasonal cycling of energy production (during winter) and shutdown (during monsoon).

Sizing the System-Cost Implications of Balancing Options: Some Initial Insights

Approach

The aforementioned results show that across all the scenarios, flexibility to integrate variable renewables is a significant challenge. Three particular challenges stand out:

- Surplus energy production at midday due to the high penetration of solar PV, necessitating the backing down or switching off of a significant portion of the thermal fleet on a regular (almost daily during high RE season) basis, or significant energy storage, or significant demand-side management and demand response in order to shift loads to daytime.
- Deficit energy production at night to meet the evening peak in the absence of production from solar PV, necessitating additional production capacities, or storage discharge, or demand-side management and demand response in order to shift load away from night-time.
- Seasonal flexibility to provide additional production capacities, notably at night, during times of low wind-energy output during the winter season. During the winter season, low electricity demand and high solar output at midday can create concurrent situations of significant energy surplus during the day.

Each of these challenges requires further analysis and modelling (see the forthcoming outputs of WP3 of this project), with a particular focus on the potential scale, characteristics, and costs of different flexibility options to meet these challenges. In this section, however, we want to provide some initial impressions as to the cost increment of meeting such a flexibility challenge. **The outputs here are intended to prompt discussion, comments, and critical thinking: they will be revised once the outputs of WP3 are available.**

One can break down the grid-integration costs of renewables into three different components:

- *Balancing costs:* This is the cost of the unpredictability of variable renewables, that is, the cost of netting out over/underproduction from renewables compared to their declared schedule. It is generally accepted that these costs are relatively low, and can be significantly reduced by measures to reduce RE forecast error and improve the liquidity and efficiency of real-time balancing markets.
- *Transmission cost:* All power plants entail transmission costs. However, RE, because of its more diffuse nature, lower CUF, and typically higher distance from load centres, is generally accepted to have additional transmission costs when compared to conventional generation.
- *Profile costs or utilization-effect costs:* These are costs that arise from the non-dispatchability of RE. Because RE cannot be dispatched when it is required, cannot (at least currently) be cost-effectively stored, is not always correlated with load, and load cannot always be shifted in time, additional capacities may be required to meet load at times when RE is not available. The cost of providing for these additional capacities is profile costs. One way of thinking about profile costs is as follows: A system with high RE may require additional capital (back-up capacities, storage, etc.) in order to meet the same load, compared to a case in which RE were perfectly dispatchable. Profile costs are the cost of that incremental capacity required to correct for the non-dispatchability of RE.

We focus here on profile costs: in the theoretical literature, these are known to be the most significant by some margin. Profile costs can be impacted by a number of factors, notably the degree of correlation between VRE and load, the production profile of VRE, the flexibility of the residual dispatchable fleet and its ratio between fixed and variable costs, and the capacity for longer-term adaptations in the system such as storage and demand response.

We approach the calculation of flexibility costs in the following manner:

- The model calculates a stylized set of additional capacities and storage options so as to reduce essentially to zero the hours of energy deficit across the year. The set consists of coal, natural gas, storage, and some demand response.
- The fixed costs of the portfolio are calculated and added to the system-wide costs, which are then levelized by the total energy output of the system. The variable costs of energy supply have already been calculated under the system costs (see Table 16), and therefore we include only the incremental fixed cost of the balancing portfolio in the calculation of system costs including flexibility.
- We assume that the flexibility portfolio is required from 2025 onwards, and hence the incremental costs begin to appear from this point onwards only.

The results give us a stylized sense of how much incremental costs would be involved in a high RE scenario. Of course, we do not cover in this way the totality of grid-integration costs: we exclude balancing costs, cycling costs, and transmission costs. However, these are known to be relatively small and more amenable to policy measures to reduce their size. Profile costs, on the other hand, are a fundamental, long-term feature of high RE systems.

Results

The results of this analysis are presented in Table 17. Unsurprisingly, the HRES has the largest cost increment for the additional flexibility required to integrate VRE (7%). This is because in this scenario the model must construct larger quantities of additional storage and production capacities to ensure system balancing, compared to the other scenarios. This is due to two separate factors: i) the VRE capacity share is higher in the HRES than in the other two scenarios; ii) there are lower dispatchable capacities in the HRES than in the other scenarios, because this scenario was constructed in order to explore a future without any additional coal beyond the current pipeline.

Secondly, according to these calculations, a high RE system still represents a cost-effective option, because the cost deflation of RE, particularly in the midterm, largely compensates for the additional capacities required to ensure system stability. The HRES scenario is modelled to be only 0.02 R/kWh more expensive than the CTS, and its system tariff including flexibility is falling as of 2029 (peaking at 5.82 R/kWh) due to the deflationary impacts of RE. By contrast, the system tariff including flexibility of the CTS is on a rising trajectory to 2030.

Table 17: Stylized calculation of the cost increment of flexibility in each scenario

Scenario	Flexibility	2022	2027	2030	Cost increment of flexibility in 2030
CPS	Without	5.47	5.60	5.55	5.0%
	With	5.47	5.79	5.83	
CTS	Without	5.36	5.50	5.50	5.1%
	With	5.36	5.69	5.78	
HRES	Without	5.46	5.51	5.40	7.4%
		5.46	5.73	5.80	

Source: TERI analysis and modelling

The analysis here is stylized and subject to significant uncertainties, pertaining, for example, to fuel-price escalation, RE capital costs, storage costs, and the availability of flexibility options such as demand response. More attention should thus be paid here to the qualitative rather than quantitative conclusions. Firstly, the additional costs of extra flexibility resources, not required to meet the annual demand but to ensure stability of sub-annual operation, are present even in scenarios with lesser RE. Secondly, the size of these costs are higher in high RE scenarios, for obvious reasons. However, even considering these costs, a high RE system is found to be relatively cost-competitive (the results for all three scenarios are well within the bounds of uncertainty, so it is reasonable to say that, given uncertainty, one is cheaper than the other). Fourthly, the deflationary impacts of declining RE mean that a high RE system is likely to become cheaper over time, even considering grid-integration costs.

Conclusions and Next Steps

This paper has presented three capacity scenarios to 2030, intended to explore various aspects of the transitions underway in the Indian power sector. These scenarios were the CPS, the CTS, and the HRES. The scenarios were explored in terms of different aspects: capacity, generation, PLF, LCOE, system costs, flexibility, and system costs including flexibility.

The main emerging conclusions are as follows:

- On an energy basis, it appears possible for India to meet the vast majority of its electricity demand growth to 2030 with RE, and considering the coal additions included in the NEP. On an energy basis, a high RE scenario with no new coal beyond the current pipeline is more challenging, necessitating, in our framework, unfeasibly high annual PLF from the coal fleet. Of course, it would be theoretically possible to add more RE in order to lower the annual PLF of the coal fleet. This would, however, place more strain on the flexibility of the system. Nonetheless, it appears incontrovertible that the emergence of RE as a key generation technology has fundamentally shifted the coal scenario to the downside.
- Annualized across the 12 years between now and 2030, the capital investment required across the three scenarios is broadly the same and significant. It reaches in the order of 1.65–1.75 trillion R/year (ca. 23.5–24.5 billion USD). This is broadly in line, albeit slightly above, the recent historical rates of investment in power-production capacities, which averaged about 1.2 trillion R/year (only coal, wind, and solar). It represents a sizeable but not infeasible financing challenge, although there are some concerns around the drag of NPAs on the financing capacities of the domestic banking and NBFC system.
- The flexibility challenges of the three scenarios share similar characteristics, but differ rather in degree. These characteristics are: the importance of daily energy shifting given the solar production during the day, large and frequent ramping requirements, and seasonal flexibility given the low generation of wind and hydro during the winter season. Our assessment is that these flexibility challenges are significant and

necessitate the introduction of additional system flexibility, even in scenarios with relatively lower RE penetration. In a high RE scenario, the presence of significant storage and demand response/demand-side management appear indispensable in the 2020s. Significant standby thermal capacities may be required during the winter in order to meet the demand during low wind and hydro days.

- On a simple per-unit basis, renewable energy has definitively proven itself cheaper than that of new coal, and cheaper than the variable costs of part of the existing fleet. However, RE does have significant grid-integration costs, and these need to be considered from a system-planner perspective when assessing the optimal trajectory for RE in India. We have provided an indicative, stylized assessment here: another, more detailed analysis should be undertaken. According to our analysis, the additional capital required to compensate for the non-dispatchability of RE is significant, comprising almost 16% of the investment requirement between now and 2030 in a high RE scenario. **However, assuming that the cost declines in RE continue, and assuming further cost declines in storage, we assess that it is still possible for a high RE power system to be highly cost-effective in the midterm com**