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Using electrolytic hydrogen production and energy storage for balancing a low carbon electricity grid: Scenario assessments for India

Rupsha Bhattacharyya [a,b,*], KK Singh [a,b], K Bhanja [b], RB Grover [a]

[a] Applied Systems Analysis, Homi Bhabha National Institute (HBNI), India
[b] Chemical Engineering Group, Bhabha Atomic Research Centre (BARC), India

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ABSTRACT

Nuclear reactors and variable renewables will play a significant role in the global energy transition as providers of low carbon electricity to various end use sectors. Real time balancing of power demand and supply without modulation or curtailment is possible using electrolytic hydrogen plants and energy storage systems. The generation mix adopted and load profiles are unique to a country and this study considers the specific case of India. This work analyses the use of grid connected water electrolysers, grid scale battery storage, hydrogen storage and fuel cells as flexible loads and dispatch schemes for grid balancing. Based on postulated long term power generation scenarios for India, the minimum required system sizes for grid balancing are estimated and techno-economic uncertainties are assessed. The use of water electrolysers is prioritized to make use of excess power, while minimizing battery storage requirement. This scheme can potentially produce a substantial share of low carbon hydrogen in India for use in industrial decarbonization, thus reducing the need for additional generation infrastructure.

1. Introduction

The global low carbon energy transition for climate change mitigation will require extensive clean electrification of fossil fuel dependent sectors like transportation and building energy systems. Industrial decarbonization will need carbon free energy carriers/raw materials like hydrogen and its derivatives, many of which will be produced by electrochemical routes. To cater to all-round increased electricity demand, particularly in rapidly developing nations and emerging markets such as India, all available low carbon electricity generation technologies including renewables and nuclear will need to be harnessed and deployed in an optimal configuration, depending on the projected energy needs, growth trajectories, resource availability, reliability of supply, and economic considerations [1].

At present, the route adopted by most nations including India towards meeting these objectives is deploying variable renewables (VREs) such as solar PV and wind farms and integrating them into their national grids. The deployment of large shares of renewables in the electricity generation mix creates significant diurnal variation in the output power dispatched through the grid due to inherent intermittency. This leads to periods when generation exceeds demand or vice versa, requiring load management or backup generators (often fossil fired) to be brought on line. Under net zero scenarios involving phase out of fossil-based generation, the role of nuclear power plants is likely to become extremely important, as baseload generators providing reliability and grid stability [2–5]. Several studies have also established that the least system-level cost of electricity supply with a high degree of reliability would benefit from having a significant contribution from nuclear reactors alongside variable renewables [6]. A low carbon energy mix should ideally consist of nuclear, renewables, fossil fuels with carbon capture, production and storage of hydrogen and use of hydrogen and captured carbon. Therefore, looking at electricity storage as the only solution for balancing supply and demand is not a cost-effective approach. One has to integrate hydrogen generation with the system in a manner that enables baseload operation of fossil and nuclear power plants, avoids curtailment of renewable generators, leads to production of hydrogen, and minimizes storage capacity needs.

1.1. Dispatchable loads for electric power grids

Energy conversion and storage technologies are expected to have a substantial role in providing flexibility and other ancillary services towards stable grid performance in low carbon electricity systems. Both

* Corresponding author.
E-mail address: rupsha@barc.gov.in (R. Bhattacharyya).

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Nomenclature

BES_m	Battery storage capacity installed, MWh(e)
$BES(t)$	Energy stored in battery at time t, MWh(e)
C_{AC}	Cost of avoiding curtailment of one unit of electricity, \$/kWh(e)
$Capex_{DM}$	Annualized capital cost of hardware deployed for demand management, \$/y
$C_{battery}$	Total capital cost of installed battery storage system, \$
CCUS	Carbon capture, utilization, and storage
C_{FC}	Total capital cost of installed fuel cell, \$
C_{H2}	Total capital cost of installed water electrolyser, \$
C_{PR}	Cost per unit of power ramp up capacity, \$/kWh(e)
CRF	Capital recovery factor, dimensionless
$C_{sp,battery}$	Specific capital cost of battery storage, \$/kWh(e)
$C_{sp,FC}$	Specific capital cost of fuel cell, \$/kWh(e)
$C_{sp,\ H2}$	Specific capital cost of electrolyser plant, \$/kW(e)
$C_{sp,tank}$	Specific capital cost of hydrogen storage tank, \$/kg H_2
C_{tank}	Total capital cost of installed hydrogen storage tank, \$
d	Discount rate per annum, fraction
E	Electrolyser rated capacity, MW(e)
$E_{battery}$	Electrical energy stored in battery, MWh(e)
$E_{sp,\ H2}$	Specific energy consumption of electrolyser plant, kWh(e)/ Nm^3 H_2
FC_m	Fuel cell stack installed capacity, MW(e)
LHV	Lower heating value of hydrogen, MJ/kg H_2 (= 120 MJ/kg H_2)
n	Life time of a given component, y
p_i	Fraction of electrical energy generated by generator i, dimensionless
$PE(t)$	Power input to electrolyser under part load operation, MW (e)
P_{H2}	Input power to water electrolyser, MW(e)
P_m	Electrolyser installed capacity, MW(e)
$SP(t)$	Excess electric power available at time t, MW(e)
SW	Shannon-Wiener Index, dimensionless
P_t	Power demand at time t, MW(e)
$q(t)$	Hydrogen production rate at time t, Nm^3/h
Q	Total hydrogen produced in a day, Nm^3
$R(t)$	Residual power at time t sent to battery storage, MW(e)
t	Time of day, h
$T_{ramp,battery}$	Time of discharge of fully charged battery, h
$T_{ramp,FC}$	Time of power discharge of hydrogen storage + fuel cell system, h
VRE	Variable Renewable Energy
$V_{storage}$	Hydrogen storage tank installed, Nm^3
Δt	Time interval, h
η_{FC}	Efficiency of fuel cell (hydrogen to electricity conversion), dimensionless
η_{RT}	Round trip efficiency of the battery system, dimensionless
ρ_{H2}	Hydrogen gas density, kg/m^3

short and long duration energy storage and associated technologies are required to provide several grid services over different time scales, ranging from fraction of a second to hours, extending to days or weeks [7].

Among well proven and mature alternatives currently available, grid scale batteries and grid connected water electrolysers are two mature alternatives. While battery storage systems currently have higher round trip energy efficiency than a power-to-hydrogen-to-power arrangement, batteries are suitable for shorter duration energy storage (typically 2 to 6 h). The power-to-hydrogen route enables longer duration storage, as it is possible to store hydrogen without losses over substantially longer durations [8]. The hydrogen can be used for industrial applications or can be re-converted to electricity when renewables might not be available for a duration beyond what has been planned for in the design of storage capacity. Producing hydrogen when electricity supply exceeds demand not only avoids curtailment or power ramp downs, but also contributes to meeting the requirement for hydrogen in industrial sectors. Setting up additional renewable generation capacity dedicated exclusively to hydrogen production may not be the most feasible option in India and elsewhere and hence this needs reconsideration.

Lithium-ion batteries represent grid scale energy storage technologies that can store excess power available from the grid. With the current grid scale battery chemistries commercially available, they can provide high discharge rates (thereby making them better suited for ramp up services) but there are constraints on their charging rates, depending on instantaneous state of charge (SOC). This can impact their ability to absorb excess power at all rates as well as their degradation rates and overall useful lives. Various redox flow batteries have also been developed and commercial scale demonstration projects have also been initiated in several countries. Even though their round-trip efficiencies are somewhat lower, they are much less dependent on critical minerals and are intended to be used for longer duration storage (6 to 11 h) than is currently achievable with lithium-ion batteries [9,10].

Water electrolysers (coupled with hydrogen storage and fuel cell systems) have also been proposed as flexible loads. Hovsapian [11] presents a list of grid services that water electrolysers can potentially provide through their dynamic operation and extremely fast responses to changes in input power. Tuinema et al. [12] have studied the potential for using grid scale electrolyser systems for frequency control applications. Using a 1 MW(e) PEM electrolyser stack, their field tests demonstrate very high ramp up rates between 0.2 MW/s (during system start up) and 0.5 MW/s (during normal operation) and ramp down rates of 0.4 MW/s. The overall dynamic response is found to be controlled by the power electronic components and the AC-DC power conversion system. They estimate that larger electrolyser plants containing multiple electrolysis modules will be capable of sustaining similar overall ramp rates in proportion to their total capacities. Varela et al. [13] have developed an optimal scheduling model for flexible operation of alkaline water electrolysers, considering various operational states and practical constraints for dynamic operation such as ramp rates and operating power range. They provide estimates of the optimal sizes and number of electrolysers to be deployed to manage variable power inputs from renewable generators. Zenith et al. [14] consider the diversion of excess wind and hydel power in selected European countries towards water electrolysers such that their spare capacity may be used and monetized while providing grid balancing services (both up- and down-regulation).

1.2. The context for India

In the Indian power sector, there has been rapid renewable capacity addition in the last few years in keeping with goals of reducing emissions intensity of the economy, but there has been inadequate storage technology deployment. As a result, for demand-supply matching, conventional coal-fired generators have been forced to operate flexibly (with ramp down to about 55 % of the rated output) [15]; this has adversely affected the economics of power production by these generators.

As coal-based generation is phased down in pursuit of net zero targets by 2070, power balancing mechanisms without the need for output modulation from base load nuclear reactors or renewables' curtailment must be established and evaluated. Thus, attention to the role of demand side measures (flexible loads and power dispatch schemes) is needed. Some of the demand side options that enable demand-supply balancing include thermal energy storage, electrical energy storage, use of excess power in applications such as desalination, hydrogen production, district energy networks and others at the grid or network level [7,16,17]. Other mechanisms also include smart metering policies to encourage demand shifting that affect energy use behaviour and trends at the individual or household levels.

This study evaluates the use of grid-connected water electrolysers and battery energy storage system as dispatchable loads which can absorb excess power output from low carbon generators, when it cannot be completely dispatched to the grid. It considers storage of the produced hydrogen for meeting India's domestic industrial requirements as well as its reconversion to electricity via fuel cells to supply power to the grid at times of peak demand and/or providing electricity to remote geographical locations. It is schematically illustrated in Fig. 1. The work examines the techno-economic aspects associated with the deployment of such a scheme and may be considered as part of resource adequacy and capacity market creation for the Indian electricity sector [18].

1.3. Motivation and scope of work

The Government of India has set a target of attaining net zero carbon emissions by 2070. Emphasis is on smart electrification of multiple sectors through deployment of all low carbon electricity generation technologies in its Long Term Low Emissions Development Strategy document (LT-LEDS) submitted to UNFCCC [19]. The National Green Hydrogen Mission launched in January 2023 recognizes the need to harness multiple benefits of low-carbon hydrogen [20]. Therefore, techno-economic considerations associated with suitable mechanisms to enable grid balancing with flexibility provided by dispatchable loads need to be evaluated as part of long-term strategies for the energy sector. This is the major motivation behind this study. So far, the mechanisms mainly adopted in India is modulation of the output from thermal power plants [21]. But as they are phased down, the role of new technologies for similar services with associated co-benefits must be evaluated in the country specific context. There have been several studies looking at balancing renewable electricity supply and demand using such technologies [22,23], but equivalent studies examining their role in the specific Indian situation are very few. This study intends to develop a simple methodology to address this gap area with the objective of helping shape integrated national energy planning. It examines sizing considerations and associated economic implications of deploying grid connected flexible loads and dispatch systems (batteries and hydrogen production for use in industry and fuel cells) to manage variability and intermittency in a low carbon electricity system.

The scope of work in this study is as follows:

i) assessment of seasonal variability and current ramping characteristics in power generation in India by analysis of electrical demand patterns over a 1-year period (2021–2022),
ii) estimation of power supply characteristics in different low-carbon generation mixes,
iii) order-of-magnitude estimation of minimum infrastructure and investment needs towards technologies such as electrolysers, battery storage systems, hydrogen storage systems and fuel cells for stable grid operation strictly without any power modulation,
iv) estimation of uncertainties in costs of the proposed schemes.

2. Analysis of electrical load curves of India

Electricity makes up about 18 % of India's final energy consumption at present. Electricity demand data from the IEA Real Time Electricity Tracker web tool covering the full year between October 2021 and September 2022 have been used for further analysis in this section. Daily average load curves at a time resolution of 1 hour, with disaggregation at weekday and weekend levels are used to represent the monthly nationwide demand patterns. The salient features extracted from these demand curves are highlighted in Table 1. Additional details are available in Supplementary Materials, Appendix I.

Fig. 2a shows the contribution of various electricity generators to total generation in India between October 2021 and September 2022. Fig. 2b shows the average hourly demand curves over the same time frame, disaggregated at the monthly level.

The following observations are made from the annual electricity demand and supply characteristics (complete data set in Supplementary Materials, Figs. A1 to A24) in the Indian electric power sector:

i) The daily electricity demand curve of exhibits two peaks, one around mid-day (between 12 noon and 2PM) and another towards the evening (between 6PM and 8PM). This is more prominent in the summer months (April to September). The mid-day peak represents the peak demand each day and the highest demands are observed between April and June, i.e., during summer, due to rising cooling requirements in increasingly warmer weather.

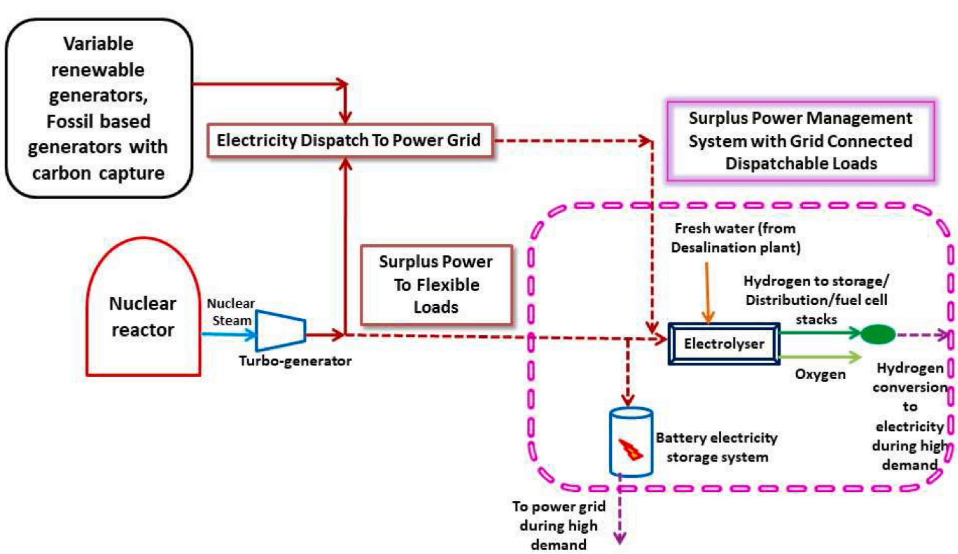

Fig. 1. Schematic showing potential demand management services using excess electricity available from a mix of low carbon electricity generators.

Table 1
Key features of electricity demand curves of India (October 2021-September 2022).

Month	Minimum/ Base load demand (GW(e))	Maximum/ Peak demand (GW(e))	Average demand (GW(e))	Standard deviation of demand (GW(e))	Max-to-Min ratio	Max-to-Average ratio	Calculated peak hourly ramp rate (GW (e)/h)	
							Ramp up	Ramp down
October 2021	138.40	168.16	152.97	7.64	1.22	1.10	7.75	7.82
November 2021	115.72	158.31	137.73	12.82	1.37	1.15	12.36	9.06
December 2021	118.29	173.06	146.46	18.03	1.46	1.18	22.97	10.63
January 2022	118.10	181.74	149.89	19.23	1.54	1.21	18.20	10.67
February 2022	134.01	190.31	160.96	18.26	1.42	1.18	26.49	9.60
March 2022	154.41	192.93	172.51	10.35	1.25	1.12	11.07	12.72
April 2022	168.70	197.29	182.06	7.16	1.17	1.08	16.39	10.97
May 2022	164.79	195.95	181.13	7.54	1.19	1.08	11.95	11.13
June 2022	167.39	196.80	184.31	7.39	1.18	1.07	10.87	11.67
July 2022	154.87	182.78	169.99	7.99	1.18	1.08	12.35	4.51
August 2022	158.18	186.25	174.24	6.82	1.18	1.07	12.65	5.09
September 2022	161.11	188.17	174.40	7.91	1.17	1.08	9.68	8.86

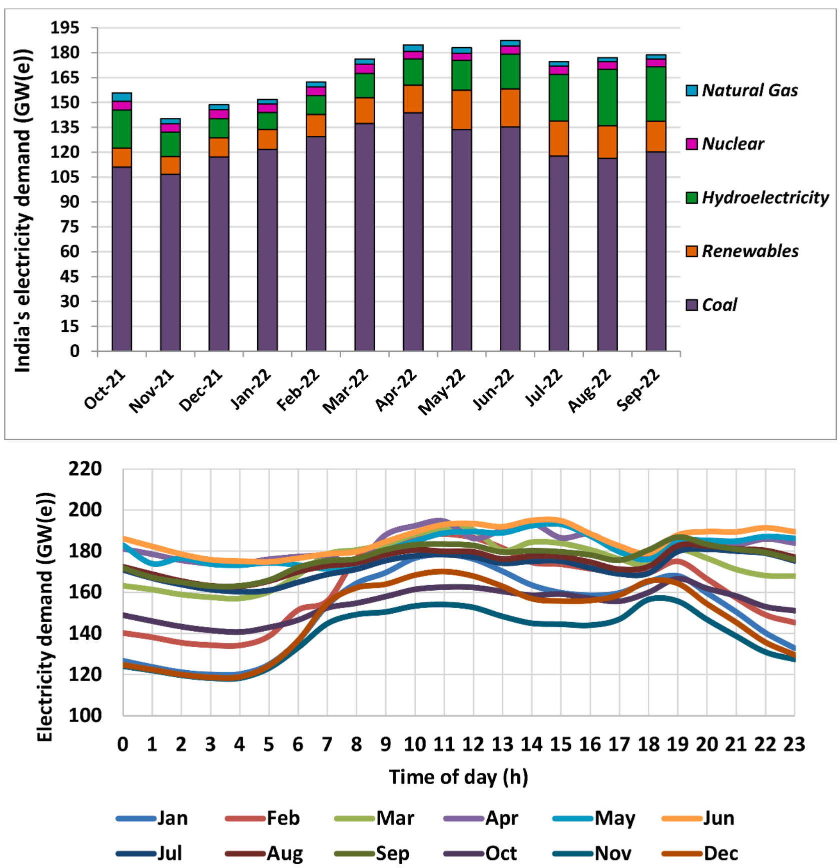

Fig. 2. a: Average contribution of different generation technologies to India's electricity mix (October 2021-September 2022) b: Hourly electricity demand profiles in India (2021–22) [(Data obtained from International Energy Agency (IEA), available at https://iea.li/3Hmd90u, last accessed on 16.6.2023)].

ii) In 2021–22, the minimum base load demand was around 116 GW (e) and the peak load was over 210 GW(e) (i.e., 1.8 times base load), which occurred on 9th June 2022, 2:47PM.

iii) Data from Table 1 indicates that the spread between the minimum and maximum demand in a day depends on the season, being larger in the winter months (between November and February) than in summer. For any month, the maximum demand can be 17 to 54 % greater than the minimum. The maximum need for flexibility in power generation is currently experienced during the winter season.

iv) From October to March (autumn-winter), the variation in hourly demand between weekdays and weekends is seen to be relatively small. But in summer months, Sundays appear to have substantially lower demand compared to weekdays and Saturdays, particularly mid-morning hours onwards. The differences in the load profiles between weekdays, Saturdays and Sundays of a given month are also observed to be statistically significant in at least some months of the year (corresponding ANOVA tables are provided in Supplementary Materials, Table A3).

v) The hourly power ramp rates (calculated as $P(t+1) - P(t))/\Delta t$) show that the ramp up rate is about 6 to 15 % and ramp down rate is 3 to 7 % of instantaneous generation rate per hour. The highest power ramp rates are seen to occur during the winter months, as opposed to highest hourly demands during summer.

vi) Coal based thermal power plants have met ~74 % of the electricity demand. The standard deviation in the month-to-month contribution from coal generators is also the largest (at about 5.2 %); the need for flexibility in power generation has largely been met by their flexible operation. The share of coal-based generation dropped during the summer months from June to September, as renewable output increased during this time.

vii) Hydro-electric power plants contribute an average of about 11.5 % to the electricity generated. The variance in hydro-electric power plant output is due to strong seasonal influence (i.e., extent of monsoon rainfall, higher share to total generation in monsoon months) and it has also partly provided flexibility, by virtue of its inherent characteristics.

viii) Despite rapid progress in renewables deployment (including solar PV and wind turbines), they have contributed less than 10 % to power generation. The observed variance in renewable output can be attributed to seasonal and diurnal variability and not due to any inherent flexibility characteristics, particularly in the absence of substantial battery energy storage facilities.

ix) Nuclear power reactors with must-run status [24] have contributed about 3 % to the electricity generated, with near base load output throughout the year.

With the need to phase down fossil based thermal power generators and increase end use electrification (e.g., transportation), it is evident that the need for non-fossil base load electricity generators, variable renewables and the demand for energy storage and flexibility services will only grow massively. A scenario-based assessment is carried out to determine the scale of technology deployment needed in India to accomplish it.

3. Excess electric power allocation philosophy to flexible loads

The nationwide power demand characteristics for India discussed in Section 2 are used as a proxy to derive scaled up demand curves for India in future, considering total energy demand forecasted by the authors in a previous study [25]. This study forecasts total energy demand in India assuming that India will reach an HDI of 0.9 in 2070. Considering that social science research [26] informs that India might reach this HDI earlier, the estimate by Bhattacharyya et al. is conservative. Also, demand curve will continue to evolve in future. However, as explained later, the broad conclusions arrived at from this study remain valid. Different generation mixes are proposed and the supply curves are calculated for each mix. Details are provided in Section 4. The difference between supply and demand is then calculated at time resolution of 1 hour. The allocation of this difference to dispatchable loads is described next.

3.1. Mathematical model for sizing dispatchable loads

A combination of water electrolysers and grid scale battery electricity storage system is proposed for demand shaping. During excess power availability this is mainly achieved through the electrolysers due to their flexibility and the need for producing low carbon hydrogen to meet decarbonization targets of various industries [27]. The grid-connected batteries, which store energy not utilized by the electrolysers therefore, have a secondary role in this scheme.

The proposed philosophy for the management of excess power from a generation mix (i.e., allocation of *SP(t)*) is as follows:

Let an electrolyser of maximum rated capacity *E* MW(e) be deployed to utilise available excess power. Let *SP(t)* MW(e) be the excess at time *t,* over the time frame up to *t*+*Δt*, where *Δt* is 1 hour. To avoid curtailing this excess, the water electrolyser system is operated (if necessary, at part load *PE(t)* MW(e)) and hydrogen is produced at the rate *q(t)* Nm^3/h. As the operating range of an electrolyser is typically between 20 % to 100 % of its rated input power, when excess electricity available is more than *E* or less than *0.2E* MW(e) it cannot be used fully by the electrolyser [28,29]. For completely avoiding power curtailment, the energy unutilized by electrolysers, designated as *R(t)* at time *t* is diverted to battery energy storage system, which stores this excess over the duration *Δt.* As a result, stored energy in the battery during *Δt* increases from its initial state of charge, defined as *BES(t),* to *BES(t+Δt)* = *BES(t)* +*R(t)Δt.* Mathematically, this ($t \in [0, 23]$) is represented as:

$$For\ SP(t) < 0.2E,\ PE(t) = 0,\ R(t) = SP(t) \tag{1}$$

$$For\ SP(t) \geq 0.2E\ \&\ SP(t) \leq E,\ PE(t) = SP(t),\ R(t) = SP(t) - PE(t) = 0 \tag{2}$$

$$For\ SP(t) > E,\ PE(t) = E,\ R(t) = SP(t) - E \tag{3}$$

$$BES(t + \Delta t) = BES(t) + R(t)\ \times\ \Delta t \tag{4}$$

For each daily load profile, the following energy balance condition is therefore always satisfied:

$$\sum_{t\ =\ 0}^{t\ =\ 23} SP(t)\Delta t = \sum_{t=0}^{t=23} PE(t)\Delta t + \sum_{t=0}^{t=23} BES(t) \tag{5}$$

The following assessments are performed for a given load profile:

i) Iterative determination of optimal electrolyser plant capacity required for maximizing use of the available excess power
ii) Determination of battery electricity storage capacity to be deployed to store the power unutilized by the electrolyser plant

The process is terminated when electrolyser size that maximizes excess power utilization (designated as P_m) and minimizes battery storage requirement (designated as BES_m) is obtained for the given excess availability profile.

3.2. Mathematical model for sizing flexible dispatch systems

The technology considered for flexible dispatch is the combination of hydrogen storage tanks and fuel cells for reconversion of hydrogen to meet peak demand along with the batteries.

The hydrogen storage unit ($V_{storage}$) is sized based on maximum daily hydrogen production from the optimally sized electrolyser. The fuel cell stack size (FC_m) is calculated based on the maximum power ramping requirement, as observed from the daily load curves.

The hydrogen production *q(t)* (in Nm^3) over time frame *Δt* when power input to the electrolyser is *PE(t)* MW(e) can be expressed as

$$q(t) = 1000\ \times PE(t) \times\ \Delta t / \left(E_{sp,\ H2}\right) \tag{6}$$

The total hydrogen production during the day (in Nm^3) can be written as

$$Q = \sum_{t=0}^{t=23} q(t) \tag{7}$$

The total production of hydrogen by the electrolyser each day is the basis of sizing the hydrogen storage tank. Thus, minimum hydrogen tank size (in Nm^3) is

$$V_{storage} = Q \tag{8}$$

The fuel cells are sized corresponding to the maximum rate at which

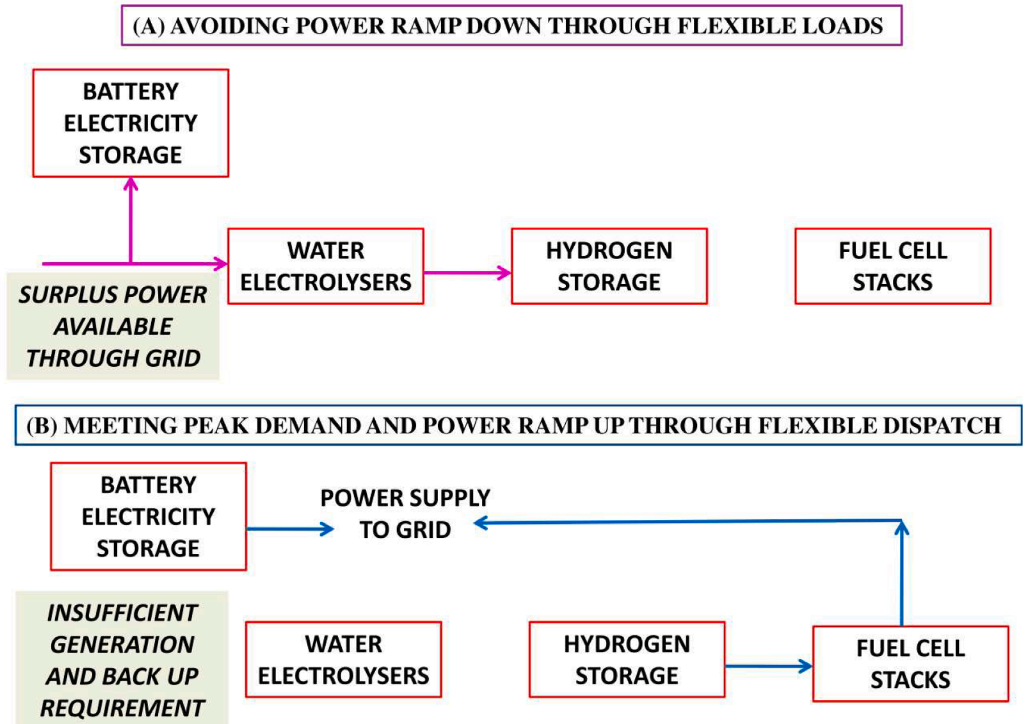

Fig. 3. Technology combination for enabling steady operation of a generation mix without ramping and curtailment.

the stored hydrogen will need to be re-electrified, based on the maximum power ramp up rates observed in the national load curves.

If demand at time t is $P(t)$ MW(e), the fuel cell stack size (in MW(e)) is therefore estimated as

$$FC_m = \max\left[\frac{dP(t)}{dt}\right] \times \Delta t,\ t \in [0,\ 23] \tag{9}$$

The additional assumptions made for the assessments of Sections 3.2 and 3.3 are as follows:

i) The dispatchable loads are assumed to be grid connected, with adequate capacity available to make complete use of excess power. Therefore, a condition of strictly zero power curtailment is imposed in estimating the system sizes. Except for the corresponding system capital costs, no additional cost of grid upgradation or connection has been considered for these loads.
ii) The water electrolyser operates at 30 bar, 60°C temperature and produced hydrogen is stored in tanks at the same pressure (i.e., without further gas compression). Under such conditions, energy required for water electrolysis (i.e., $E_{sp,H2}$ including that for producing high purity water) is about 5 kWh(e)/Nm^3 H_2 [30].
iii) Excess electricity is assumed to be available at zero cost to the dispatchable loads, in the absence of other demand shifting mechanisms such as electric vehicle battery charging or time of day based tariffs that would encourage certain loads (e.g., non-emergency domestic loads) to be met only when lower cost excess electricity is available.
iv) All flexible loads such as electrolysers, fuel cells and batteries are assumed to respond and adjust instantaneously to changes in excess power availability or shortage without time lags.
v) No annual degradation in the performance of any of the components has been considered in the analysis.
vi) The batteries and hydrogen storage tank are sized so that they can store the entire amount of produced hydrogen and excess electricity respectively each day. Thus, the system capacities estimated in this study are the minimum required sizes of these technologies.
vii) Battery depth of discharge is taken as 80 % in all cases for calculation of battery capacity.

3.3. Techno-economic cost-benefit assessment model

After estimating the sizes or required minimum installed capacities of the dispatchable load hardware (i.e., P_m MW(e) of electrolyser capacity and BES_m MWh(e) of battery capacity), the capital investment needs are estimated.

The capital cost of the electrolyser plant (in \$) to be installed is (corresponding to the minimum unutilized excess power),

$$C_{H2} = 1000\ \times P_m \times C_{sp,H2} \tag{10}$$

The power law scaling relationship between electrolyser cost and its production capacity is obtained from literature [31].

The capital cost of battery storage (considering its round-trip efficiency) to be installed is

$$C_{battery} = \frac{1000\ \times BES_m \times C_{sp,battery}}{\eta_{RT}} \tag{11}$$

The capital cost of the hydrogen tank is

$$C_{tank} = C_{sp,\ tank} \times V_{storage} \times \rho_{H2} \tag{12}$$

The capital cost of the fuel cell stack is given by

$$C_{FC} = 1000\ \times FC_m \times C_{sp,\ FC} \tag{13}$$

The maximum time duration (in hours) over which the installed fuel cell can continue to work with the stored inventory of hydrogen and provide power output at its peak rated capacity is given by

$$T_{ramp,FC} = \frac{\rho_{H2} \times V_{storage} \times LHV \times \eta_{FC}}{FC_m \times\ 3600} \tag{14}$$

The corresponding maximum discharge time (in hours), with power extraction at the peak ramp up rate (like the fuel cells), for the installed

Table 2
Input data for techno-commercial assessments.

Parameter	Minimum value	Most likely value	Maximum value	Remarks (Data References)
Electrolysers and Fuel Cells				
Electrolyser (AWE) capital cost, including stack and balance of plant components ($/kW(e))	750	1200	2000	Designated as $C_{sp,H2}$ [33–37]
Electrolyser (PEM) capital cost, including stack and balance of plant components ($/kW(e))	1500	1800	2500	Designated as $C_{sp,H2}$ [33–37]
Fuel cell capital cost ($/kW(e))	1000	2000	3000	Designated as $C_{sp,FC}$; extrapolated from data for smaller scale units [38]
Hydrogen storage system capital cost ($/kg H_2)	350	425	700	Designated as $C_{sp,tank}$; Engineered storage structures such as over-ground tanks considered for analysis; [39]
Electrolyser plant life (y)	5	7	10	[31]
Fuel cell life (y)	5	7	10	[38]
Fuel cell efficiency (%)	55	60	70	PEM fuel cells considered [38]
Hydrogen storage system life (y)	10	15	25	[39]
Grid scale Battery Storage Systems				
Li-ion battery capital cost (including cells and battery pack) ($/kWh(e))	330	402	500	Designated at $C_{sp,battery}$ [8,40,41]
Redox flow battery capital cost ($/kWh(e))	172	242	339	Designated at $C_{sp,battery}$; data for the all-vanadium chemistry has been considered [10]
Li-ion battery life (y)	5	7	13	[8,40,41]
Redox flow battery life (y)	3	6	8	[8,40,41]
Round trip efficiency of storage-retrieval cycle of Li-ion battery (%)	80	85	90	[8,40,41]
Round trip efficiency of storage-retrieval cycle of redox flow battery (%)	65	75	85	[8,40,41]
Other factors				
Project discount rate (% p.a.)	4	9	15	Based on capital structure and risk perception associated with project; values comparable with current renewable energy projects in India are used [42]
Electricity cost ($/kWh(e))	0.03	0.05	0.08	Reported values [43]

battery from its fully charged condition is

$$T_{ramp,\ battery} = \frac{BES_m \times \eta_{RT}}{FC_m} \tag{15}$$

The annualized capital investment (in $/y) in hardware for avoiding curtailment of power output is

$$Capex_{DM} = C_{H2} \times CRF_{H2} + C_{battery} \times CRF_{battery} \tag{16}$$

where the capital recovery factor *CRF* is calculated as (separately for electrolyser, fuel cells, hydrogen storage system and battery storage system, due to their different useful life times)

$$CRF = \frac{d(1+d)^n}{((1+d)^n - 1)} \tag{17}$$

Neglecting any operating costs, overheads, and considering only the additional capital investment for electrolysers, and battery storage, the minimum annualized cost of avoiding curtailment (C_{AC}) of each unit of excess electricity is therefore given by

$$C_{AC} = \frac{Capex_{DM}}{\sum_{t=1}^{t=24\ \times\ 365} 1000\ \times SP(t)\Delta t} \tag{18}$$

For re-electrification of stored hydrogen and export to the grid, the total annual hydrogen production and the installed fuel cell capacity are used to estimate the cost (designated as C_{PR}) at which each unit of electricity can be exported to the grid, beyond available capacity.

$$C_{PR} = \frac{C_{tank} \times CRF_{storage} + C_{FC} \times CRF_{FC}}{\sum_{t=1}^{t=24\ \times\ 365} q(t) \times \rho_{H2} \times LHV \times \eta_{FC} \times\ 0.278} \tag{19}$$

In this work, two kinds of water electrolysers (i.e., alkaline water electrolyser/AWE and proton exchange membrane electrolyser/PEME and two kinds of grid scale battery storage systems (Li-ion battery systems and flow battery systems) are considered as the flexible loads. The batteries and hydrogen gas storage with PEM fuel cells act as the flexible dispatch system when power ramp up is required. The operation philosophy is illustrated in Fig. 3, where (A) indicates the situation when excess power is available from the grid and (B) illustrates the case when the generators have inadequate capacity to meet peak loads.

The required techno-commercial input data are provided in Table 2. The data are described in the form of triangular probability distributions based on ranges of values available in current literature. This enables a random number-based sampling technique (e.g., Monte Carlo simulations) to be used to choose various values of input variables. This allows determination of a range of C_{AC} and C_{PR} values under different uncertain input scenarios, considering the long timeline of assessment. The sample size is taken as 10^5. Full details of this procedure are described in a previous work of the authors [32].

4. Candidate generation mixes and projections for India in 2070

4.1. Long term demand and postulated supply side scenarios

India's power demand has grown at a compounded rate of about 5 % per annum in the last decade, with higher growth rate in the post-pandemic period. According to previous estimates by the authors, by 2070, the total annual electricity consumption is expected to be about 24,000 TWh(e). About 30 to 40 % of final electricity consumption will be for production of energy carriers like hydrogen, while the rest goes to directly electrified services [25]. Thus, on average, 65 % of total final energy demand i.e., 15,600 TWh(e) will be in the form of electricity and 24,000 – 15,600 = 8400 TWh(e) will be required for indirect electrification, via hydrogen generation. Average direct hourly electricity demand is expected to be 1781 GW(e). These figures are used as the basis for developing supply side scenarios.

Assessment of renewable energy harvesting potential in India (using current technologies) indicates that peak solar potential is about 750 GW(e), wind potential at height of 120 m is 695 GW(e), hydroelectricity potential is 71 GW(e) and biomass-based generation is 25 GW(e). At average annual capacity utilization factors of 0.23, 0.30, 0.40 and 0.65 respectively and assuming full deployment of all these technologies, these generators will be able to provide 1531, 1826, 249 and 128 TWh (e) per annum respectively. Therefore, in the strict net zero scenario (without considering use of negative emissions technologies), the balance [15,600 - (1531+1826+249+128)] = 11,866 TWh(e) would have to be supplied by leveraging nuclear reactors and fossil fuel-based

Table 3
Estimation of grid scale deployment needs of flexible loads and dispatch schemes for balancing demand and supply in India at 2070.

	Solar PV	Wind	Hydro electricity	Biomass with CCUS	Fossil with CCUS	Nuclear	Excess energy availability and cumulative ancillary hardware requirement
Annual capacity factor	0.233	0.300	0.400	0.650	0.700	0.875	–
Scenario A							
Installed capacity (GW (e))	750.00	695.00	71.00	25.00	1732.08	300.96	Annual excess: 5039 TWh(e) Water electrolysers: 2332 GW(e)
Annual generation (TWh(e))	1530.81	1826.46	248.78	128.12	9559.00	2306.83	Battery storage: 2033 GWh(e) Daily hydrogen storage: 0.33 MT
% Share in annual generation	9.81	11.71	1.59	0.82	61.28	14.79	Fuel cells: 1093 GW(e) Carbon capture: 7.3 Giga ton/y
Scenario B							
Installed capacity (GW (e))	1050.00	868.75	71.00	25.00	1539.28	300.31	Annual excess: 5611 TWh(e) Water electrolysers: 2292 GW(e)
Annual generation (TWh(e))	2143.13	2283.08	248.78	128.12	8495.00	2301.89	Battery storage: 1880 GWh(e) Daily hydrogen storage: 0.37 MT
% Share in annual generation	13.74	14.64	1.59	0.82	54.46	14.76	Fuel cells: 1137 GW(e) Carbon capture: 6.5 Giga ton/y
Scenario C							
Installed capacity (GW (e))	1050.00	868.75	71.00	25.00	1122.98	600.05	Annual excess: 5800 TWh(e) Water electrolysers: 2352 GW(e)
Annual generation (TWh(e))	2143.13	2283.08	248.78	128.12	6197.50	4599.39	Battery storage: 2035 GWh(e) Daily hydrogen storage: 0.38 MT
% Share in annual generation	13.74	14.64	1.59	0.82	39.73	29.48	Fuel cells: 1101 GW(e) Carbon capture: 4.8 Giga ton/y
Scenario D							
Installed capacity (GW (e))	1050.00	868.75	71.00	25.00	978.19	704.30	Annual excess: 5878 TWh(e) Water electrolysers: 2372 GW(e)
Annual generation (TWh(e))	2143.13	2283.08	248.78	128.12	5398.45	5398.44	Battery storage: 2116 GWh(e) Daily hydrogen storage: 0.38 MT
% Share in annual generation	13.74	14.64	1.59	0.82	34.61	34.61	Fuel cells: 1088 GW(e) Carbon capture: 4.2 Giga ton/y

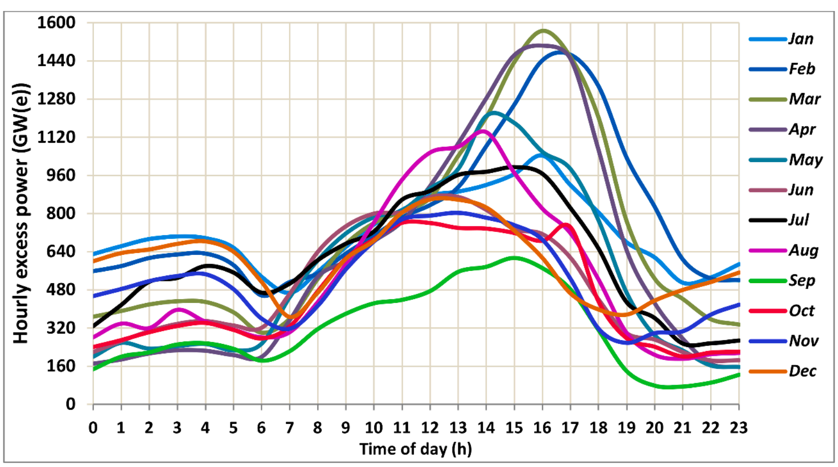

Fig. 4. Projected excess power availability profile in India in 2070 (corresponding to generation mix in Scenario A in Table 4).

Table 4
Expected annualized costs of avoided power modulation.

Technology combination	Service provided	Annualized capital investment per unit of excess power ($/kWh(e))
1. AWE + Li-Ion battery	Excess power absorption to avoid ramp down	0.145 ± 0.029
2. AWE + Redox flow battery	Excess power absorption to avoid ramp down	0.132 ± 0.029
3. PEME + Li-Ion battery	Excess power absorption to avoid ramp down	0.146 ± 0.029
4. PEME + Redox flow battery	Excess power absorption to avoid ramp down	0.133 ± 0.029
5. Fuel cell + Hydrogen storage	Provision of power ramp up capacity during deficit	0.299 ± 0.074

generation with carbon capture and storage (CCS).

Out of G TWh(e) to be supplied by these generators, let F TWh(e) be provided by fossil-based generators and $N = G - F$ TWh(e) be provided by nuclear generators. Taking average annual capacity factors to be 0.7 and 0.875 for fossil and nuclear power plants respectively, the required installed capacities will be ($1000*F/0.7$) and ($1000*N/0.875$) GW(e) respectively. Considering 10 % energy penalty for carbon capture, the actual fossil installed capacity required will be ($1.1 \times 1000F/0.7$) GW (e).

In this study, four candidate scenarios (named A to D) are considered for illustration:

(A) Full renewable capacity deployment based on available estimates

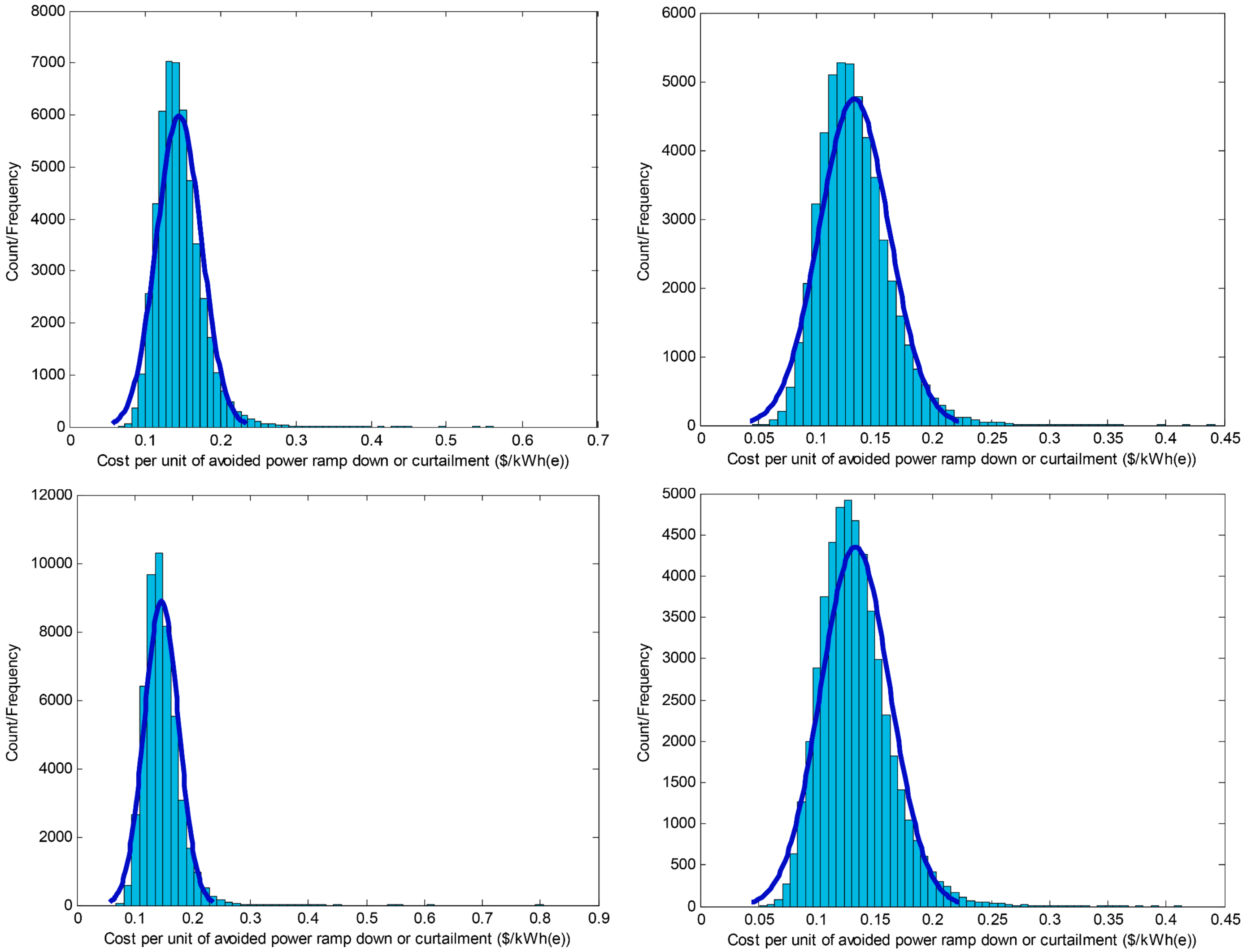

Fig. 5. A: Distribution of annualized capital cost per unit of avoided power curtailment using AWE and Li-ion batteries (Mean = $ 0.145/kWh(e), Standard deviation = $ 0.029/kWh(e))
B: Distribution of annualized capital cost per unit of avoided power curtailment using AWE and Redox flow batteries (Mean = $ 0.132/kWh(e), Standard deviation = $ 0.029/kWh(e))
C: Distribution of annualized capital cost per unit of avoided power curtailment using PEME and Li-ion batteries (Mean = $ 0.146/kWh(e), Standard deviation = $ 0.029/kWh(e))
D: Distribution of annualized capital cost per unit of avoided power curtailment using PEME and Redox flow batteries (Mean = $ 0.133/kWh(e), Standard deviation = $ 0.029/kWh(e)).

using current state-of-the-art technologies, with balance made up by fossil fuel-based generation and nuclear generation. The potential nuclear contribution to total generation is based on and extrapolated from previous energy planning studies for India, which envisage around 255 GW(e) of installed nuclear capacity for net zero, giving $F{:}N \sim 4{:}1$ [44].

(B) Enhanced contribution from renewables using advanced technologies, with balance made up by fossil fuel based generation and nuclear generation ($F{:}N \sim 3.7{:}1$). Here solar panel efficiency enhancement from 15 to 21 % and wind turbine hub height increase from 120 to 150 m are considered.

(C) Enhanced contribution from renewables using advanced technologies, with balance made up by fossil fuel-based generation and nuclear generation in the ratio $F{:}N \sim 1.3{:}1$.

(D) A "well-diversified" scenario considering the Shannon-Wiener (*SW*) index representing the diversity of the generation mix is also considered. It is calculated using Eqn. (20).

$$SW = \sum_{i=1}^{6} p_i \log_2 p_i \tag{20}$$

Here p_i represents the fraction contributed by each of the six generation technologies in Table 3 towards meeting overall demand. A higher value of *SW* represents greater diversity of the mix and hence indicates a more resilient energy mix, as there is less dependence on any one form of electricity generation [45]. For fixed maximum contributions from solar, wind, biomass and hydel power in each scenario, greater diversity will be ensured by reduction of the share of fossil-based generation while increasing nuclear share in India's energy mix correspondingly. The well diversified scenario would therefore have equal contributions from these two generation technologies (i.e., $F{:}= 1{:}1$) as that maximizes the value of *SW* to 2.011 (compared with Scenario A, B and C values of 1.684, 1.836 and 2.000 respectively).

The hourly generation profile for a given energy mix is estimated as follows:

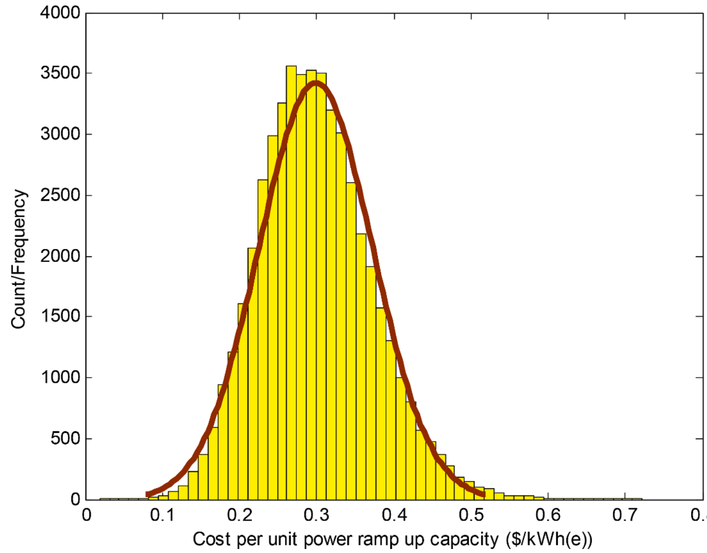

Fig. 6. Distribution of annualized capital cost per unit of power ramp up capacity (Mean = $ 0.299/kWh(e), Standard deviation = $ 0.074/kWh(e)).

i) The typical time varying generation profiles of solar and wind generators are estimated using characteristics of current commercially available PV modules (full details provided elsewhere [30]) and wind turbines (specifications from https://www.vestas.com/en/products/offshore/V164–10–0-MW, hourly wind speed data from Indumati et al., [46]). No additional uncertainties in these forecasts are considered.
ii) For hydroelectric generators, the seasonal variation in generation is considered and is used to estimate the monthly load factors; these are used to determine the monthly contributions to generation for given installed capacity.
iii) In case of nuclear, fossil and biomass generators, steady hourly outputs are considered; thus, their installed capacities multiplied by average annual capacity factors provide the corresponding hourly supply values.

The hourly supply profiles from different generators are combined to obtain cumulative generation profiles for the country. Based on the current demand curves and their scaled up form to reflect the increased demand in 2070, the hourly excess power availability is estimated as the supply-demand difference. One may note that demand variation during the day influences battery charging and electrolyser operation profile. Essentially the demand gets integrated and therefore, any evolution of the demand profile over the years will not influence the broad conclusions of this study.

For example, Fig. 4 shows the projected excess power availability on an hourly basis for each month of the year, for the specific case of Scenario A (from Table 3). Here, the minimum excess is about 75 GW(e) and maximum is about 1566 GW(e). The minimum excess is not zero since installed capacities of different generators are calculated based on average capacity factors; the instantaneous cumulative output from all generators can exceed the instantaneous demand at certain hours, especially during low demand hours. The corresponding sizes of grid-connected demand management hardware (electrolysers, batteries, hydrogen storage and fuel cells) for steady grid operation are determined as before. Results are indicated in Table 4.

5. Results and analysis

5.1. System size estimation

The excess energy available from the installed generators over the course of the year is found to be 21 % to 24.5 % of total final demand, in scenarios A to D. The excess also represents 59.9 % to 69.1 % of the estimated energy required for indirect electrification.

The results in Table 4 show that for absorbing this excess and ensuring steady grid operation, grid connected electrolyser capacity of 2292 to 2352 GW(e) and battery storage of 1880 to 2035 GWh(e) will have to be deployed, depending on the generation mix adopted. The corresponding daily hydrogen production potential using only excess electricity is estimated to be 0.33–0.38 million tons, which is about 60–69 % of estimated daily hydrogen demand by 2070 [25]. Utilising excess power reduces the need for separate generation or electrolyser capacity deployment exclusively for hydrogen production; this underscores the need for integrated planning for the energy and industrial sectors. Continued dependence on fossil and biomass-based power generation would also need installed carbon capture capacities of 4.2–7.3 giga ton per year (assuming carbon emissions intensity of 750 gm CO_2-eq/kWh(e)).

The calculated battery storage capacity requirement represents storage of about 3.2 % of the electricity demand per day. Batteries (and other energy storage options) will mainly contribute towards storing excess renewable energy and for supplying additional power during ramp up requirements and phases of peak demand and/or low generation.

5.2. Techno-economic assessments

5.2.1. Minimum investments for avoiding power ramp down

Based on the flexible load sizes estimated in Table 3, the additional specific capital investment of avoiding modulation of power generators have been estimated. The calculated distribution of values of C_{AC} for different representative combinations of input parameters for individual technologies are shown in Figs. 5A-D. The results are consolidated in Table 4. The contribution of the capital cost of the battery storage system to the overall demand management system is found to be 92.3 ± 1.5 % to 94.5 ± 0.9 %, thus the battery system dominates the cost of providing excess power absorption capability to the grid. For this reason, the type of electrolyser is also seen to have lower influence on the specific investment needed for avoiding curtailment.

5.2.2. Minimum investments for providing power ramp up

The calculated values of C_{PR} for different representative combinations of input parameters relevant to hydrogen storage-fuel cell system are shown in Fig. 6. The contribution of the capital cost of the hydrogen storage system to the overall power ramp up system is found to be 4.1 ±

1.3 %, thus the fuel cell system dominates the cost of providing power ramp up facilities. The investment per unit of power ramp up capacity through hydrogen reconversion in fuel cells is seen to be about 2 times the investment needs of absorbing the excess power through a combination of electrolysers and batteries. It may therefore be concluded that the hydrogen derived from excess power should primarily meet the broader objectives of industrial decarbonization. Its reconversion to electricity should not be prioritized.

6. Summary and conclusion

The study evaluates the techno-economic implications of the use of water electrolysers, battery electricity storage, hydrogen storage and fuel cells for a low-carbon generation mix in India. No power modulation or curtailment and complete utilization of excess power has been assumed. The current nationwide load curves are used as baseline data to make long-term order-of-magnitude projections for 2070. The main findings are:

(i) The use of energy conversion and storage technologies like grid scale batteries and water electrolysers as flexible or dispatchable loads for enabling demand-supply matching is technically feasible. The specific investment required a combination of batteries and electrolysers to avoid power curtailment is $ 0.132 ± 0.029/kWh(e) to $ 0.146 ± 0.029/kWh(e). For fuel cells-hydrogen storage systems to provide power ramp up service, investment needed is about $ 0.299 ± 0.074/kWh(e).

(ii) Battery costs dominate the capital investment needed to avoid power curtailment or ramp down, while installed electrolyser capacity with much lower share of the capital investment requirement is the primary provider of the flexibility service. This approach enables co-production of low carbon hydrogen for industrial decarbonization.

(iii) The economic considerations inform that the use of fuel cells for re-electrification of the produced hydrogen should not be prioritized and battery systems should provide ramp up services when needed.

(iv) Considering 4 candidate generation mixes involving 6 low carbon technologies in 2070, the total excess energy available can be 20–24.5 % of total final electricity consumption, depending on the generation mix adopted.

(v) The nationwide grid connected electrolyser capacity of at least 2292–2352 GW(e) and battery storage of 1880–2035 GWh(e) will be required for complete excess utilization without power modulation. Carbon dioxide capture capacity of 4.2–7.3 giga ton per year will be needed to continue using fossil fuel/biomass-based power plants.

(vi) Daily hydrogen production from the excess power allocated to grid connected electrolysers can be about 0.33–0.38 million ton, which is about 60–69 % of the average daily projected hydrogen demand in 2070. This not only reduces the need for dedicated geenration capacity for hydrogen production but also reduces the need for battery electricity or other forms of energy storage for matching demand and supply.

This work emphasizes the need for system level studies in designing optimally integrated future energy systems. A diverse mix of low carbon generators and use of electrolysers and hydrogen storage with battery storage for flexibility services addresses the twin objectives of energy sufficiency and industrial decarbonization simultaneously.

The energy mix to be finally adopted is strongly influenced by the national context, which differs from country to country. For India, it will depend on the availability of advanced nuclear reactor technologies that can augment nuclear fuel supply (such as liquid metal-cooled fast reactors with closed fuel cycle operations, and molten salt breeders with online reprocessing), carbon capture and storage technologies, improved renewables and energy storage technologies, availability of sites for construction of power plants and resource constraints. While nuclear energy is a well-studied subject, so is not the case with renewables and carbon capture and storage. Studies on externalities associated with the growing use of renewables have been taken up only in recent years [47,48], and there is a great deal of uncertainty in the risks and liability of carbon dioxide storage [49]. Considering these aspects will also influence the evolution of the low-carbon energy mix.

CRediT authorship contribution statement

Rupsha Bhattacharyya: Writing – review & editing, Writing – original draft, Visualization, Software, Methodology, Formal analysis, Data curation. **KK Singh:** Writing – review & editing, Supervision. **K Bhanja:** Writing – review & editing, Supervision. **RB Grover:** Writing – review & editing, Supervision, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Supplementary materials

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