



A systematic capacity assessment and classification of geologic CO₂ storage systems in India

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ABSTRACT

With rising carbon dioxide emissions and ambitious global targets for climate change mitigation, carbon sequestration has become one of the most promising carbon dioxide removal technologies. It can prove especially beneficial to an emerging country such as India, which must balance its rapid economic growth with a reduction in emissions. A detailed assessment of the cumulative storage capacity is necessary to facilitate the development of CO₂ storage pathways in India. Previous assessments for India have primarily estimated the theoretical storage capacity based on limited data. In this study, we have reviewed different methodologies for estimating storage capacities globally, and based on the most current data available, in a first, developed a systematic assessment for theoretical and effective CO₂ storage capacities for different geological formations in India. Four storage pathways with adequate potential have been identified: storage through CO₂ enhanced oil recovery (EOR), enhanced coalbed methane recovery (ECBMR), storage in deep saline aquifers, and basalt formations. The results indicate considerable potential for CO₂ storage in India, especially in saline aquifers (291 Gt) and basalt (97–316 Gt). Even though the storage capacity estimated through EOR (3.4 Gt) and ECBMR (3.7 Gt) is comparatively less, it is adequate to store emissions from nearby large point sources. These methods are also highly feasible due to the ready availability of infrastructure and extensive geological information about the basins involved. In addition, we have developed novel classification systems for different basins in India to represent their prospectivity for CO₂ storage.

1. Introduction

Anthropogenic carbon dioxide levels in the atmosphere have been rising continuously at an alarming rate for the past few decades. The severity of climate change was recognized at a global scale when the 2015 Paris Climate Agreement (PCA) was signed by 190+ state parties (United Nations Climate Change, 2015). The mutual goal of this agreement was of limiting the global temperature rise to 2°C above pre-industrial levels and endeavoring to sustain it at below 1.5°C (Rogelj et al., 2018). In order to track the performance of involved parties and quantify the intended goals of the PCA, the Intergovernmental Panel on Climate Change (IPCC) (IPCC, 2013; Metz et al., 2005) introduced a carbon budget of 2900 Gt, which puts an upper bound on the total amount of carbon dioxide emissions. From pre-industrial levels

(1870), anthropogenic CO₂ emission has reached nearly 2400 Gt, consuming more than 75 % of the budget and leading to a temperature rise of nearly 1.1°C. According to the current levels of annual anthropogenic CO₂ emissions, 500 Gt more of CO₂ emissions will most likely lead to crossing the PCA target of 1.5°C (Friedlingstein et al., 2020; IPCC, 2021; Le Quéré et al., 2018).

The scope of limiting climate change does not only include reducing consumption but also carbon negative emissions. In the business-as-usual (BAU) scenario, an estimated 640–950 Gt of CO₂ needs to be removed from the atmosphere to limit the temperature rise to 1.5°C by the end of the century (Luderer et al., 2018). According to the International Energy Agency (IEA) (IEA, 2019), Carbon Capture and Storage (CCS) will contribute 13 % of the cumulative emissions reduction needed by 2060 in the Clean Technology scenario. The IPCC estimates

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that CCS will play a major role in decarbonizing the industry sector, with a requirement of CCS deployment at a scale of 3–7 GtCO₂/yr by 2050 in the 1.5°C pathways (Rogelj et al., 2018). According to Zoback and Gorelick (2012), an estimated 27 Gt of CO₂ needs to be stored in the ground per year worldwide by 2050 for the technology to make a meaningful impact on reversing climate change. However, we are currently able to manage only 40 Mt (~0.15%) annually (Global CCS Institute, 2020). Cumulatively, more than 300 Mt of CO₂ is already sequestered in various geological formations worldwide, which have over 12,000 Gt of total CO₂ storage potential (Global CCS Institute, 2020; Loria and Bright, 2021). Even if we store the IPCC-recommended 2.3 Gt CO₂ per year, it will last us about 10000 years, proving to be an extremely sustainable pathway for carbon mitigation. To meet the climate targets of IPCC model pathways, we need to store up to 1200 Gt of CO₂ by 2100. India's annual emission has shown a 3.1% compounded annual growth rate (CAGR) since the last three decades, which has rendered CCS as an immediate measure to restrict the increasing atmospheric CO₂ concentration.

India is a responsible global citizen and has vowed to reduce the per-capita CO₂ emissions in near future (TIFAC, 2018; UNFCCC, 2015). India has also signed the Paris agreement and committed itself to reducing the emissions intensity of its GDP by 33 to 35 % by 2030 from the levels of 2005. A more significant challenge for India is the utilization of captured CO₂ due to expensive retrofitting requirements, deficiency in optimization, cheaper conventional energy resources, and the lack of economic strength in consumers to buy products that are produced from utilized carbon. The urgency of implementing large-scale carbon capture and storage projects in India considering the current economic and policy framework has been emphasized by Vishal et al. (2021). Immediate opportunities lie in enhanced oil recovery (EOR) and enhanced coalbed methane recovery (ECBMR), which will eventually lead to a certain degree of enhanced energy security for India. Development in these technologies will eventually enable CO₂ storage in unused saline aquifers and basalt formations, which have shown considerable storage potential (Kearns et al., 2017). The large volume of CO₂ sinks will also allow for a long-term and sustainable mitigation pathway for the captured CO₂. According to the Fifth Assessment Report (AR5) that was published by Working Group III of the IPCC (Jewell et al., 2016; Krieglert et al., 2014; Tavoni et al., 2013), India needs to drastically cut down its CO₂ emissions from all sectors through CCS to even

approach the restricting of CO₂ concentration in the atmosphere to less than 450 ppm (Fig. 1). Despite all these statistical analyses and indications to strengthen the storage aspect, critical capacity assessment of these sinks has not yet been performed in detail. Moreover, with fast-changing statistics in the energy sector due to continuous resource exploration and discoveries, a current and comprehensive assessment of the cumulative storage capacity of CO₂ is of utmost importance. It is also corroborated by the India Energy Outlook 2021 (IEA, 2021), which highlights that “India's CO₂ storage potential has not yet been properly mapped. Given the important role likely to be played by CCUS in a variety of sectors in India, if CO₂ can be securely stored, there is a strong case for defining the potential and understanding how its geographic distribution might influence future investments in industry and power.”

To develop infrastructure to implement CCS, the total capacity of different storage systems needs to be estimated at the outset. The capacities can be ‘theoretical’, ‘effective’, and ‘practical’ or ‘viable’ (Bachu et al., 2007), depending on the level of constraints applied. Based on these, a resource-reserve catalog for the country can be created, which would enable interested stakeholders to assess the viability of storage projects at a national and basinal scale. Further constraints such as source-sink matching need to be applied at the feasibility stage to narrow down to specific sites. The current study is an attempt to provide fresh estimates of the CO₂ storage capacity of India in different geological formations. We have assessed the storage potential for CO₂ in EOR, ECBMR, deep saline aquifers, and basalt formations. Wherever data has permitted, effective capacity estimates have been developed, and existing theoretical capacities have been updated. The current study fills the gaps that may lead to large-scale storage project assessments in India.

2. Estimation of CO₂ storage capacity

2.1. Classification of storage capacity

The concept of resources and reserves has been used to categorize geological commodities such as hydrocarbon and mineral accumulations around the world. The storage capacity for CO₂ also signifies a geological commodity; therefore, a similar concept has been applied by the Carbon Sequestration Leadership Forum to classify its availability (Bachu et al., 2007; Bradshaw et al., 2005; Gorecki et al., 2009a). “Resources” are defined as estimations of the total amount of commodity present in a geographic area: a field, basin, country, and so on. “Reserves” signify a subset of the total resources that can be commercially recovered based on the existing state of techno-economic conditions. The assessment of reserves requires the application of several technical, environmental, and socio-economic constraints. As a result, a large amount of resources is deemed impractical to recover. Resources can be grouped into discovered (in-place) and undiscovered (inferred). Discovered resources are those whose existence has been confirmed to a high level of certainty based on detailed data acquisition and interpretation, while undiscovered resources are those that have not been detected yet but are presumed to exist based on extrapolations from geological and other information from the area. The different levels of resources and reserves are encapsulated in the Techno-Economic Resource-Reserve Pyramid for CO₂ storage capacity (Bradshaw et al., 2007, 2005). In this system, the bottom of the pyramid is occupied by the ‘theoretical capacity,’ which represents the volumetric limit of the storage system. It usually indicates the upper limit of the capacity, which refers to the entire pore space of the geological formation after accounting for the irreducible saturation of residual fluids. The ‘effective capacity’ or the ‘realistic capacity’ constitutes the portion of the theoretical capacity that is technically available. It is obtained by applying storage efficiency coefficients to the theoretical capacity, and incorporates physical and technological constraints in storage. The ‘practical capacity’ or the ‘viable capacity’ corresponds to the reserves mentioned previously and involves economic, legal, and regulatory

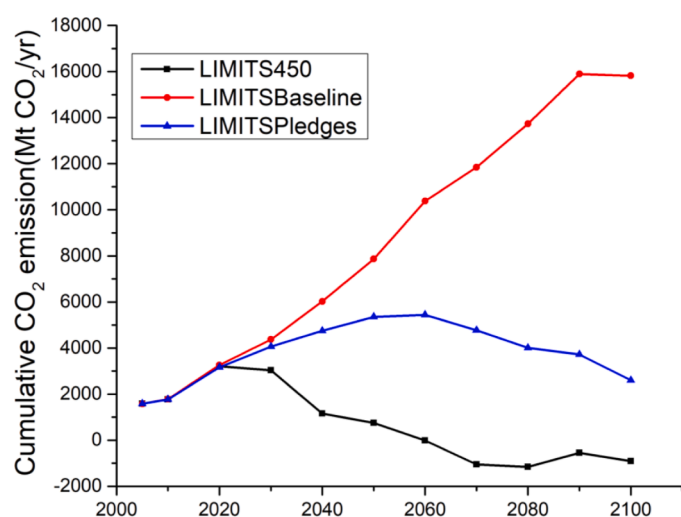


Fig. 1. Cumulative CO₂ emission from various sources in India. Real data till 2020, followed by tentative emission metrics to achieve different milestones. LIMITS 450 shows the most ambitious emission goals to restrict the global CO₂ concentration to within 450 ppm. The baseline shows the BAU scenario, whereas Pledges indicates the implementation of moderate climate policies (Jewell et al., 2016; Krieglert et al., 2014; Tavoni et al., 2013).

limitations. Lastly, 'matched capacity' represents the capacity that is obtained through source-sink mapping.

Another widely used classification system is based on SPE's Petroleum Resources Management System (PRMS) (SPE, 2018a, 2007), which was initially developed in 2007 and updated in 2018. The PRMS enables the classifying of hydrocarbon resources based on the potential recovery of these resources from geological formations; however, a CO₂ storage resources classification system is used to categorize the total storage volume that is available (Allinson et al., 2014). Nonetheless, several authors around the world have proposed classification systems by modifying the PRMS to adapt to CO₂ storage resources such as the Cooperative Research Center for Greenhouse Gas Technologies (CO2CRC) (Kaldi and Gibson-Poole, 2008), CO₂ Storage Resource and Capacity Classification (Frailey and Finley, 2009), the Energy & Environmental Research Center (EERC) (Gorecki et al., 2009b), the US Department of Energy (DoE) (Rodosta et al., 2011), the Carbon Storage Capacity Management System (CSCMS) (Allinson et al., 2014), and the CO₂ storage capacity classification system (Liu et al., 2014). To bridge the inconsistencies and to streamline the definitions that are proposed in the different classification systems, SPE has developed its own CO₂ Storage Resources Management System (SPE, 2018b). The system maintains the division of resources into discovered and undiscovered storage resources. The discovered resources are subdivided into 'storage capacity' (commercially accessible resources) and 'contingent storage resources' (sub-commercial, but potentially accessible capacity). The undiscovered storage resources comprise 'prospective storage resources', which are potentially accessible in uncharacterized geological formations through future development. The 'inaccessible storage resources' refer to a subset of total storage resources that are potentially unusable at the time of estimation.

2.2. Review of estimation methodologies

Estimating the total capacity of geological formations in an area is a complex process. To simplify the process at the regional or national scale, several rough assumptions need to be made. This leads to large uncertainties in the estimates and widely conflicting results based on the methodology applied. The estimations for cumulative storage capacity in formations around the world range from 100 to more than 100,000 Gt of CO₂ (Bradshaw et al., 2007). The basic principle of capacity estimation involves the calculation of the available pore volume in the rock formations and assessing the pore volume fraction accessible by CO₂ through different trapping mechanisms. However, the methodologies differ in their choice of models, equations, and techno-economic constraints used, which results in diverse storage efficiencies.

In 2004, the Carbon Sequestration Leadership Forum (CSLF) task force for 'Review and development of standard methodology for storage capacity estimation' reviewed the existing estimates and compared the approaches in order to establish standardized methodologies and definitions for CO₂ storage capacity estimations in depleted hydrocarbon fields, unminable coal beds, and saline aquifers (Bradshaw et al., 2005; CSLF, 2008). Other national and international organizations also recognized the necessity to design methodologies of their own and develop better regional capacity estimates to exploit these resources. Some of the major storage capacity estimates have resulted from the assessments made by organizations such as US DOE (Goodman et al., 2011), US Geological Survey (Blondes et al., 2013; Brennan et al., 2010), IEA Green House Gas (IEAGHG) Programme (IEAGHG, 2009), North American Carbon Atlas Partnership (Wright et al., 2013), British Geological Survey (BGS) (Bentham et al., 2014; Gammer et al., 2011; Holloway et al., 2008), Australian Carbon Storage Taskforce (Carbon Storage Taskforce, 2009), Queensland CO₂ Geological Storage Atlas (Bradshaw et al., 2011), Research Institute of Innovative Technology for the Earth (RITE) in Japan (Ogawa et al., 2011), and Federal Institute for Geosciences and Natural Resources (BGR) (Knopf and May, 2017). Reviews of assessments for different regions show considerable variations

between the methodologies and the assumptions made in them (Heidug, 2013; Prelicz et al., 2011). For this study, we compare and analyze the CSLF, US DOE, and IEAGHG approaches in the context of the CO₂ storage capacity estimation for India.

The methodologies that are proposed by CSLF, US DOE, and IEAGHG to assess CO₂ storage capacity are generalized such that they can be employed for any geological unit depending on the availability of sufficient data. The IEAGHG methodology (Wildenborg et al., 2005) is the simplest in comparison to the other two and was developed for quick estimates of CO₂ storage capacities (especially of deep saline aquifers) in large areas that lack extensive geological characterization. The methodology considers only the total area covered by the sedimentary basins in the region, and it assumes that suitable storage sites exist in over half of the total area. An equivalent theoretical capacity is obtained by multiplying the net thickness (assumed to be 100 m) with half of the reservoir area. To estimate the effective capacity, approximate storage efficiency factors are applied to the total volume of the reservoir. Overall, every square km of the basin area is assumed to have a storage capacity in the range of 0.1 to 1 Mt of CO₂. The smaller value corresponds to closed systems, the capacities of which are pressure-limited, while the larger value either corresponds to open systems that have large areal extents or where the pressure is managed through the extraction of fluids.

The CSLF and US DOE methods are quite similar, with marginal deviations in the proposed definitions and the formulation of the storage efficiency factors (Gorecki et al., 2009b). The efficiency factors used in the two methods can be directly related through the relation:

$$E = C_c(1 - S_{wirr}) \quad (1)$$

where E and C_c are the efficiency factor that is formulated in the CSLF and US DOE methods, respectively; and S_{wirr} is the irreducible water saturation. Equivalence can also be made between the respective definitions: US DOE 'CO₂ resource estimate' corresponds to CSLF effective capacity, and US DOE 'CO₂ capacity estimate' to CSLF 'practical capacity'. However, they differ in the technical limitations that they apply to the reservoir under consideration. The CSLF method considers both free-phase and dissolved CO₂ in its estimation and constrains the volumetric trapping to structural and stratigraphic traps in saline aquifers. The US DOE method, on the other hand, considers only free-phase CO₂ in storage but includes the entire formation pore volume while ignoring the technological limitations (CSLF, 2008). However, it excludes aquifers that are shallower than 800 m to avoid contamination of potable water resources. The CSLF method compensates for this by providing screening criteria, which are recommended by the IPCC (Metz et al., 2005), for storage sites. As such, the CSLF method should provide estimates that are technically closer to the practical capacity, but it requires a high level of detail in geological characterization to provide accurate estimates. The US DOE method is more straightforward in comparison, but it is optimal in regions where comprehensive data are absent.

3. Geologic storage potential of Indian basins

3.1. Sedimentary Basins of India

India has a total of 26 major sedimentary basins, which cover a cumulative area of approximately 3.4 million square kilometers (DGH, 2020). This is spread across onland, shallow water (extending up to 400 m isobath), and deep-water horizons (from 400 m up to the Exclusive Economic Zone (EEZ)). They have been classified by the Directorate General of Hydrocarbon (DGH), India, into three major categories solely based on the occurrence of economically recoverable known hydrocarbon resources (Category-I, Category-II, and Category-III) (DGH, 2017). As the exploration widens, more resources and data are added to each basin, and the categorizations may be updated subsequently. Based on the existing classification, the CCS potential of these three different

basin groups is given below.

Category-I: Basins in this category have a considerable amount of discovered in-place hydrocarbon accumulations that are commercially recoverable, and they have the potential for further increased recovery. When viewed from a CCS perspective, these are the most crucial basins because the oil industry has built extensive infrastructure on them through decades of exploration and production. This infrastructure can be retrofitted to carry out CCS operations. Additionally, the abundance of data available for these basins will ensure reduced cost and effortless prospect analysis. Seven basins, which cover 30 % of the total basinal area, are grouped under this category: the Mumbai offshore, Krishna–Godavari, the Assam Shelf, Cambay, Rajasthan, Cauvery, and the Assam–Arakan Fold Belt.

Category-II: Resources in Category-II basins are currently sub-economic but have the potential to become economical in the future, which might lead to their development. These basins have good prospects for CCS and will become potential targets once the storage resources in the Category-I basins are used up. Five basins, which cover 23 % of the total basinal area, are under this category: Mahanadi, Kutch, Vindhyan, Saurashtra, and Andaman.

Category-III: Minimal infrastructure exists in Category III basins, and not much data has been generated for them; this makes them the least attractive option for CCS. Although they hold enormous storage potential, exploration and infrastructure development costs will hinder CCS development in these basins. Fourteen basins that cover 47 % of India's basinal area are grouped under this category. However, the Bengal Basin, which falls under this category, has started producing oil since late 2020, making it the eighth hydrocarbon producing basin in India (Business Standard, 2020).

3.2. Analysis of storage capacity estimation for India

Indian basins have not yet been explored for CO₂ storage; therefore, no data has been generated for such storage. The only available insights are previous estimations of the storage capacity, which were made by a few authors using the exploration and production (E&P) data from the petroleum industry, and the publicly available data on basins in India. These estimates lie in the range of 47 to 572 Gt of CO₂ (Viebahn et al., 2014) and describe either theoretical or effective storage capacity. However, most of these estimates are quite simplified in their methodology and approaches. Table 1 shows an overview of the previous estimates for storage capacities in India, which are categorized by different mechanisms. The study conducted by Dooley et al. (2005) was a first-order assessment and resulted in a total capacity of 105 Gt of CO₂ with over 100 Gt of storage in deep saline aquifers. Another study (Singh et al., 2006), based on rough assumptions and numerical formulation, estimated the storage capacity in basalts at 200 Gt and the overall capacity at 572 Gt of CO₂. The most detailed estimation of the storage capacity in the Indian subcontinent until now, which was made by the IEAGHG R&D Programme (Holloway et al., 2008), bases the

capacity on only the areal extent of the basin without considering the sediment thickness or the geology; however, both play a crucial role in determining the total accessible pore volume in the geological formations. Consequently, there is a need to update and develop more accurate estimates of CO₂ storage capacity in India based on standardized methodologies and improved knowledge of the storage processes in the subsurface.

4. Methods

In this study, we have dealt explicitly with technically feasible CO₂ storage while excluding economic or regulatory constraints because India has yet to implement a comprehensive policy to deal with CO₂ storage. We have also excluded the possibility of pressure management (production of reservoir fluids during injection) but have assumed that the formations have enough areal extent such that pressure constraints can be ignored. To avoid contamination of potable groundwater resources, we have excluded depths of up to 1000 m from the formation volume (Brennan et al., 2010; Gammer et al., 2011; Knopf and May, 2017). The detailed methodologies to assess CO₂ storage in different storage mediums are described here.

4.1. Assessment of capacity through CO₂ EOR

CO₂ EOR is an efficient and economical way of storing CO₂ in depleted oil fields. The capacity estimation of CO₂ storage through EOR usually involves certain assumptions. The fundamental assumption that the volume previously occupied by produced oil is now available for storage is usually valid for pressure-depleted oil reservoirs with low water-cut (Peck et al., 2017). This is usually the case with reservoirs that have not undergone secondary recovery through water flooding. In fields with a high water-cut, presumably due to hydrodynamic contact with deep aquifers, CO₂ counters the influx of water in the reservoir due to high injection pressures. Nevertheless, a fraction of the pore volume will be occupied by connate water due to capillary, viscous, and gravity forces. Another assumption is that the influx of CO₂ restores the reservoir pressure in the range of virgin pressure and is not enough to limit the total capacity or cause significant geomechanical complications (Bachu, 2016).

Due to extensive exploration activities, hydrocarbon reservoirs are usually characterized in detail, and as a result, comprehensive information about the geologic formations is available on which we can base our storage capacity estimates. Many of the assumptions that are needed in other forms of storage can be avoided. Primarily, the total storage volume is calculated as the sum of all reservoir volumes rather than the product of approximate areal cover and thickness (Bachu, 2016; Hill et al., 2020; Mishra et al., 2020; Warwick et al., 2017). This enables more accurate estimates of storage potential. In India, however, there is an overall limited public availability of data for oil fields, which primarily resides with the major hydrocarbon operators in the country. The key source of information is the National Data Repository by DGH, the overseeing governmental body in India, which provides only basin-wise Original Oil-in-Place (OOIP) and recoverable hydrocarbon reserves in the country. Assessments done previously in India have also relied on basinal-level data to analyze storage capacity (Holloway et al., 2009, 2008). Furthermore, we have selected only Category-I basins for CO₂ EOR assessment as all of them currently have operational oil fields, and consequently, OOIP and reserves data.

For the current study, we have used detailed volumes for in-place hydrocarbon resources and ultimate recoverable reserves (URR) for each of the basins provided by DGH based on the current exploration assessment (DGH, 2020). The pore volume that is accessible by CO₂ corresponds to the cumulative volume that is occupied by URR in the respective basins. To calculate the volume of oil in Mm³ from the ultimate recoverable resource (URR) data in million metric tonnes of oil equivalent (MMTOE), a standard conversion value that is equal to 1.165

Table 1
Summary of existing estimates of CO₂ storage capacity in India

Storage category	Dooley et al. (2005)	Singh et al. (2006)	Holloway et al. (2008)	Kearns et al. (2017)
CO₂ storage capacity (Gt)				
Storage in saline aquifers	102	360	142	-
Storage through EOR	2	7	1.1	-
Storage through ECBMR	2	5	0.345	-
Storage in Basalt	-	200	-	-
Total	105	572	143	99–697

is used. Next, assuming a 10 % tertiary recovery factor through EOR (RF_{EOR}) from Original Oil-in-Place (OOIP) (Ganguli, 2017), the extra volume is added to the reserves. Thus, the total pore volume available, V , is obtained through the equation:

$$V = URR + (OOIP \times RF_{EOR}) \quad (3)$$

The pore volume thus obtained could be further reduced to allow for water penetration into the reservoir through connected aquifers or water injection for secondary recovery. However, there might already be residual water in the reservoir during secondary migration. Therefore, the volume thus obtained would be fully available for CO_2 . From the reduced volume, the CO_2 mass estimate is derived by the equation (Holloway et al., 2008),

$$M_{CO_2} = VB_0\rho_{CO_2} \quad (4)$$

where B_0 is the formation volume factor applied, and ρ_{CO_2} is the density of CO_2 at reservoir conditions. The formation volume factor is taken as 1.2 in the absence of field-specific data. The density of CO_2 is affected by the in situ temperature and pressure conditions, which in turn depend on depth, local geothermal gradient, reservoir pore pressure, etc. To simplify the problem, we estimated the reservoir pressure and temperature of these basins using averaged input parameters. The pressure was assumed as the hydrostatic pressure at the average depth calculated for individual basins. The temperature was calculated by multiplying the depth with a 35°C/km geothermal gradient selected based on available data for different basins (Das and Srivastava, 2015; Ganguli et al., 2018; He and Zhou, 2019; Majumdar and Devi, 2021; Majumdar and Nasipuri, 2008; Phayre et al., 2011; Singh, 2020; Singh et al., 2016). The estimated pressure and temperature values for each basin were used to derive the corresponding CO_2 densities (Span and Wagner, 2003).

The methodology mentioned above, however, only provides us with theoretical capacity estimates. In order to estimate the effective storage capacity, Peck et al. (2017) have described a method in which CO_2 storage efficiency factors that are derived from a data set of 31 CO_2 EOR sites across the United States (Azzolina et al., 2015) can be directly multiplied with the OOIP value of any basin to obtain its storage potential. The fundamental formula that guides the calculation of the storage capacity is

$$M_{CO_2} = OOIP \times RF \times UF_{CO_2} \times \rho_{CO_2} \quad (5)$$

where, M_{CO_2} is the mass of the stored CO_2 , and UF_{CO_2} is the net CO_2 utilization factor.

The CO_2 EOR incremental oil recovery factor and the CO_2 net utilization together represent the CO_2 storage efficiency factor, $E_{oil/gas}$, which can be directly used for CO_2 storage calculations. The formula can be reduced to

$$M_{CO_2} = OOIP \times E_{oil/gas} \times \rho_{CO_2} \quad (6)$$

From the practical experience of the major oil companies that are involved in EOR, it is considered economical until roughly a maximum of three hydrocarbon pore volume injections (HCPV) of CO_2 , after which the production declines below the break-even point. The hydrocarbon pore volume is the volume of the pore space within the reservoir, which is occupied by oil, and it is generally used to quantify the volume of fluids injected for additional oil recovery. Previous EOR projects have injected 0.4 HCPV CO_2 in the hydrocarbon fields, but current practices inject CO_2 in the range of 1 HCPV (Cooney et al., 2015; Jiang et al., 2019; Shi et al., 2017). The efficiency factors that are obtained for 10th, 50th (median), and 90th percentile values for 0.5, 1, 2, and 3 HCPV injection scenarios (Azzolina et al., 2015) are listed in Supplementary Table 2. When the values are applied to Eq. 5., we obtain a range of effective storage capacities, and the most probable value is assumed to be the one that is obtained through the 50th percentile efficiency value. The resultant storage capacities are then compared with capacities obtained using the recommended global reference value of CO_2 stored per

barrel of oil recovered (0.29 t/bbl) (Cooney et al., 2015), which provide us with the viable capacity.

4.2. Assessment of capacity in coal formations

Anthracite and bituminous coal contributes to ~95% of coal reserve in India (up to a depth of 1200 m) spread across Gondwana Basin (Permian age) and scattered in some parts of northeastern India (Tertiary age) (Indian Minerals Yearbook, 2020). Coal formations are rich in methane with even oversaturated reservoirs in some parts of Damodar Basin. These conditions provide ample opportunity for the economic exploration of CBM. Proximity to several large-scale thermal power plants also creates an opportunity for ECBM recovery by injecting captured CO_2 into depleted reservoirs with minimal transportation cost and a higher methane-recovery rate. This process also symbiotically drives the mitigation of captured CO_2 through subsurface trapping. The higher affinity of organic matter toward CO_2 than toward CH_4 allows an increase in the volume of storage capacity. The $CH_4:CO_2$ storage capacity in coal seams may vary from 1:3 (Oudinot et al., 2017; Vishal et al., 2013b) to 1:2 (Gunter et al., 1997), depending on the rank, permeability, and organic matter composition of coal. The effect of permeability, water saturation, well configuration, sorption time, gas composition, pressure condition, and such others on the storage capacity of a reservoir have already been explored in great detail (Mazzotti et al., 2009; Palmer, 2010; Ross et al., 2009; Syed et al., 2013; Vishal et al., 2015, 2013a).

Predicting the CO_2 storage capacity requires consideration of geo-mechanical, hydrodynamic, and petrophysical properties of a reservoir; hence, it can only be performed through a very minute inspection of each reservoir. In addition, India's energy scenario is quite dynamic, and the resource-reserve calculation of coal changes every year, which leads to a variation in the total CO_2 storage capacity. The capacity estimation of an individual reservoir is considerably different from the estimation for the whole country, which presents a wider array of variables, forcing us to consider more assumptions for a simplified approach. The base for capacity estimation lies in volumetric and material balance equations, which consider the gas properties in the reservoir, but negate the properties of the reservoir itself (Boyer and Qingzhao, 1998). Understanding the dependence of sorption capacity on the pressure condition and the permeability of the reservoir further enabled the refining of the calculation methods to incorporate reservoir properties while estimating storage (Dutta et al., 2011; Vishal et al., 2015, 2013a). Changes in the storage capacity of coal with varying ranks have also been investigated in detail, indicating that lower grade coal has a higher $CO_2:CH_4$ storage ratio than higher grade coals (Schepers et al., 2010). Mathematical models and reservoir simulation software have been developed to estimate the capacity of reservoirs by taking into account reservoir properties, gas properties, and their change over time (Gonzalez et al., 2009; Koperna et al., 2009; Oudinot et al., 2017; Ozdemir, 2009; Pashin and McIntyre, 2003; Reeves and Oudinot, 2004; Vishal et al., 2018, 2013b).

India currently has 319 Gt of coal resources concentrated in the Gondwana and Tertiary coal formations (Geological Society of India, 2018). Concentrated in the southern and western parts of India, are 45.6 Gt of lignite resources. The majority of the coal resources (more than 90 %) are of the non-coking grade, which has good CO_2 storage potential (Holloway et al., 2009). Jharkhand, Orissa, and Chhattisgarh hold the majority of the coal resources, most of which are at a depth range of 300–600 meters. To estimate the CO_2 storage capacity, in this study, we will focus predominantly on Indian coal reserves, leaving lignite out of scope. The properties of the coal and the total resources at different depths are shown in Supplementary Table 7. The statistics of the depth-wise distribution of coal are collected from GSI, 2018 report (Geological Society of India, 2018). We have segmented the coal reservoirs as allocated reservoirs and unallocated reservoirs. Allocated reservoirs are further classified according to their block allocation sequence between 2002 and 2010, as mentioned by DGH (DGH, 2017;

Prabu and Mallick, 2015).

4.3. Assessment of capacity in saline aquifers

The capacity for CO₂ in aquifers is estimated by calculating the net volume of the formations suitable for storage and applying appropriate storage efficiency factors. The efficiency factors assimilate different reservoir properties such as porosity, relative permeability, lithology, and others, at in situ pressure and temperature conditions (Bachu, 2015). After reviewing the different methodologies to compute the efficiency factor and the level of detail available for Indian sedimentary basins, we chose to base our approach on the US DOE methodology (Goodman et al., 2011). The methodology assumes an open system for its calculation of the storage efficiency, which means that either the reservoir is assumed to be large enough to act as “infinite-acting” or extraction of reservoir fluids is used to manage the pressure buildup. The governing equation for capacity estimation can be expressed as:

$$G_{CO_2} = Ah\phi\rho E \quad (7)$$

where G_{CO_2} is the total mass of CO₂ storage resource, A is the area covered by the basin, h is the gross thickness of the formations in the basin, ϕ is the average porosity, ρ is the CO₂ density at the reservoir conditions, and E is the estimated storage efficiency factor. The total efficiency factor comprises efficiency components such as the net-to-total area ($E_{An/At}$); net-to-gross thickness ($E_{hn/hg}$); effective porosity as a fraction of the total porosity ($E_{\phi_e/\phi_{tot}}$); volumetric displacement (E_v) as a product of areal, vertical, and gravitational displacement efficiencies (IEAGHG, 2009); and microscopic displacement efficiency (Bachu et al., 2007; Doughty and Pruess, 2004). Thus, the equation for the storage efficiency factor becomes

$$E = E_{An/At} E_{hn/hg} E_{\phi_e/\phi_{tot}} E_v E_d \quad (8)$$

Goodman et al. (2011) estimated the quantiles (P10, P50, P90) of efficiency factors for different lithologies based on information from Carbon Sequestration Atlases of the United States and Canada (Deel et al., 2008; US DOE - NETL, 2010) by using Monte-Carlo simulations. The calculated efficiencies from the simulations range from 0.4% to 5.5% (Supplementary Table 3) for three dominant lithologies: clastics, dolomites, and limestone. These values agree with other regional studies of efficiency in saline formations with open boundaries (Kopp, 2009; Szulcowski and Juanes, 2009).

For Indian sedimentary basins, there are only limited detailed lithological data for majority of the basins. The most detailed data exists for category I basins, but is mostly restricted by oil and gas operators. For the rest of the category II and III basins, the data is patchy and non-uniform across the basin itself. In our study, we have utilised the most reliable and consistent geological information available for Indian basins: the most recent India's Hydrocarbon Outlook (DGH, 2020), DGH basin summary reports, the Geology of India published by Geological Society of India (Ramakrishnan and Vaidyanadhan, 2010), and other relevant research papers, and used the knowledge to determine the dominant lithology type (sandstone, carbonates, shales) for each basin. Based on the dominant lithology, the respective efficiency ranges (Supplementary Table 3) are applied to each of the basins in India. To select the appropriate quantile value (P10, P50, or P90), we referred to the study by (Kopp et al., 2009a), where they calculated storage efficiency values for several reservoir models with perturbations of properties such as depth, temperature, and the like, from the base case. A clear trend was observed, in which the efficiency improved with increasing depth. Hence, we classified the Indian basins, based on their respective depths, into shallow, medium, and deep. The deeper basins that had sediment thicknesses greater than 5 km were assigned the higher quantile values (P90); the shallow basins that had thicknesses less than 1.5 km were assigned lower quantile (P10) values, and P50 values of efficiency were chosen for medium basins with depths in the range of

1.5 to 5 km.

To calculate the total effective volume in the basins that are suitable for storage, the gross thickness needs to be estimated. We have excluded the top 1000 m from the total thickness of the basins to avoid storage in shallow reservoirs, which risks contamination of potable aquifers (Heidug, 2013). Previous methodologies (Holloway et al., 2008; Singh et al., 2006) have generalized the thickness to 100 m. In our methodology, however, we have assumed a thickness that is 1.5 % of the effective net thickness of the sediments, which results in values that are similar to previous assessments but provides a more realistic and proportional basin-wise approximation. Next, the density needs to be estimated to calculate the total mass of CO₂ that can be stored in the accessible volume thus obtained. The methodology used for obtaining the density for different basins is the same as that used in capacity estimation through EOR. Finally, the obtained density is multiplied with the effective volume to calculate the total mass of CO₂ that can be stored. The respective properties of the different sedimentary basins in India are given in Supplementary Table 4.

4.4. Assessment of capacity in basalt

Currently, most of the carbon sequestration projects worldwide involve the injection of CO₂ into large sedimentary basins. The primary trapping mechanism for CO₂ in such formations is structural and residual gas trapping. However, mineral trapping, which involves the conversion of carbon dioxide into carbonate minerals, ensures a much more permanent form of storage. However, it happens at a slow rate, and the kinetics of mineralization are debated (Kelemen et al., 2019; Zhang and DePaolo, 2017). To use the mineral trapping mechanism more effectively, CO₂ injection has been experimented with in basalt formations. Basalts have an advantage over sedimentary rocks: they are much more reactive and drastically reduce the time that is required for injected CO₂ to convert into carbonates (Snæbjörnsdóttir et al., 2020).

Although the potential of CO₂ storage in the Deccan basalt in India (Misra et al., 2016; Pandey et al., 2016) has been fairly researched, there is a severe lack of data that is focused on storage mechanisms in an Indian context. To date, no standardized methodology to estimate the capacity of basalts in the world exists. The only reliable estimates have come from data acquired in geothermal reservoirs, which act as a reference to overcome the limitations of the scarcity of data. Natural analogs have shown that up to 70 kg of CO₂ can be stored in a cubic meter of basaltic rock (Gislason and Oelkers, 2014), and observations suggest that it can vary significantly based on the local geology (Weise et al., 2008). In our analysis, we considered several methodologies used globally for storage capacity estimation in basalts (Callow et al., 2018; Goldberg et al., 2008; Kang et al., 2018; McGrail et al., 2006; Snæbjörnsdóttir et al., 2014). From these, we applied the widely used criteria set by Snæbjörnsdóttir et al. (2014) and McGrail et al. (2006) to estimate the bounds of CO₂ storage capacity of basalts in India.

Snæbjörnsdóttir et al. (2014) base their method on a study done by Weise et al. (2008) on the amount of CO₂ mineralized as calcites in basaltic rocks in the geothermal systems of Iceland. Three geothermal systems were considered in their study: Krafla, Hellisheidi, and Reykjanes. The CO₂ content, measured from samples of drill cuttings, ranged from 28.2 (Reykjanes) to 73.1 tons (Krafla) of CO₂ per square meter of surface area in the uppermost 1500 m of the formations. The Reykjanes analog provides us with the lower limit of storage efficiency, while the Krafla system provides the upper limit. In order to calculate the net pore volume of the formations suitable for CO₂ storage, it is assumed that a channel system dominates the permeability over one-sixth of its upper 600 m, and the average channel porosity is 10 % (Goldberg and Slagle, 2009; Goldberg et al., 2008). The method used by McGrail et al. (2006), however, assumes an interflow thickness of 10 m, 10 suitable interflow zones, average porosity of 15 %, and 1000 m as the targeted depth of injection. This leads to a storage factor of roughly 41 kg CO₂ per cubic meter of formation pore volume. They applied their

criteria to estimate the CO₂ storage potential of Columbia River Basalts in the USA, which cover more than 174,000 km² of area, to be more than 100 Gt. These storage capacities per unit volume for the different methodologies are then multiplied with the net pore volume available in basalt formations in India to yield an approximate capacity estimate for the country.

5. Results and Discussion

5.1. Storage potential in oil and gas fields

There are 26 sedimentary basins in India, of which seven belonging to Category-I have been producing oil, while several of the reservoirs are on the path to depletion. Since late 2020, Bengal Basin has also initiated hydrocarbon production, making it the eighth functional oil-producing basin in India. However, due to the lack of reserves data, it has been excluded from the present study. Assuming that EOR is carried out in the seven basins as a tertiary recovery phase, it yields a cumulative production in the range of 1100 Mt of additional oil on an average, when the recovery is assumed equal to 10 % of OOIP. The recovery factor of 10 % is based on observed values in various global EOR projects (Bachu, 2016; Karacan, 2020; Merchant, 2017) and also corroborates with EOR efficiency predicted in the Cambay Basin (Ganguli et al., 2016). To calculate the storage capacity through this additional recovery, the methodology described for CO₂ EOR assessment in this study has been implemented on publicly available hydrocarbon-in-place and ultimate reserves data (DGH, 2020) (Table 2) and basin properties listed in Supplementary Table 1 and 4. The estimates of CO₂ storage capacity have been divided into different levels based on the resource pyramid (Bachu et al., 2007). The first-level estimate (theoretical capacity) is equal to 3.4 Gt of CO₂. The theoretical capacity incorporates extra oil recovery from tertiary methods (10 %) and assumes the presence of residual water along with hydrocarbons in the reservoirs. However, if we assume that water is introduced into the reservoir through connected aquifers or secondary recovery, we have to account for irreducible water saturation occupying a part of the pore space, reducing the total capacity to 2.8 Gt (Supplementary Table 1). Fig. 5 shows the storage capacities of Category-I basins in India.

The resulting capacity can be considered as the total theoretical capacity. Subsequently, the effective capacity for CO₂ storage which is associated with the incremental recovery is 2.07 Gt on an average in a 1 HCPV-injection scenario; the lower and upper estimates are 755 Mt and 5.2 Gt, respectively (Supplementary Table 5). In a typical EOR operation, CO₂ and water are alternately pumped into the reservoir through the injection wells, which leads to oil flow into the production wells because of the reduction in oil viscosity and the increase in buoyancy. The volume of CO₂ injected to achieve this is a function of reservoir properties, its complexity, and most importantly, the OOIP (Lake, 1989). A larger OOIP indicates a larger volume of recoverable oil and, subsequently, the requirement of a higher volume of CO₂. Since EOR is primarily focused on economically recovering additional oil and not on filling up the reservoir with CO₂, the quantity of injected fluids is optimized such that the costs stay low. In the methodology followed, the quantity of CO₂ stored through EOR is calculated for 0.5, 1, 2, and 3 HCPV-injection scenarios. Considering that current EOR practices cumulatively inject 1 HCPV CO₂ (Cooney et al., 2015; Jiang et al., 2019;

Shi et al., 2017), storage based on a 1 HCPV-injection scenario is chosen as the best approximation.

Apart from this, Cooney et al. (2015) provided a range of CO₂ storage values in global EOR projects. Using the recommended EOR best practices storage value of 0.29 t/bbl of oil recovered through tertiary recovery, we estimated a viable storage capacity of 1.2 Gt to compare with the calculated effective capacity. Therefore, the combined estimates suggest an immense potential for CO₂ storage through EOR in the different basins of India. The different levels of estimates based on the resource pyramid are shown in Fig. 2.

Despite the substantial storage capacity that has been estimated by the methodology adopted in this study, a qualitative analysis of the oil and gas fields in India, which was done by Holloway et al. (2009), summarized that India lacks large fields that can store lifetime emissions from nearby large point sources such as power plants, cement, and steel industries. Nevertheless, assessment studies are currently underway to identify potential sites. Gandhar field in the Cambay Basin is one such site that has been identified by the Technology Information Forecasting and Assessment Council (TIFAC), Government of India, in the very first CCUS Roadmap for India (TIFAC, 2018). The roadmap proposes the feasibility study of the Gandhar field as a future pilot project for CO₂ EOR. Potential discoveries in Rajasthan and the Krishna–Godavari Basin will also provide possibilities for the progress of EOR in the country.

The push towards CO₂ storage through EOR makes sense because it is more feasible and economical than pure storage in geological formations. Depleted oil and gas fields provide the certainty of long-term storage with proven retention of hydrocarbons in them. The rejuvenation of the reservoir to its original pressure also reduces the risks of induced seismicity, which are usually associated with fluid injection and withdrawal projects (Ellsworth, 2013). Compared to injection in closed formations, depleted fields are also not constrained by limitations in capacity due to pressure buildup. Moreover, the ready availability of

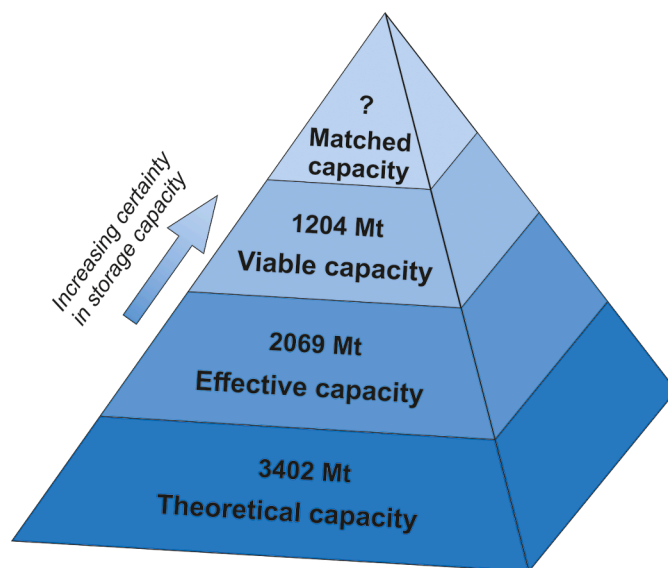


Fig. 2. CO₂ storage capacity of India through EOR at different levels of estimation based on the resource-reserve pyramid.

Table 2

Total and basin-wise theoretical CO₂ storage capacities through EOR based on hydrocarbon resources data by DGH (DGH, 2020)

	Krishna– Godavari	Mumbai	Assam shelf	Rajasthan	Cauvery	Assam–Arakan	Cambay	India (Total)
HC-in-Place (MMTOE)	1977.00	4794.00	1868.00	938.00	292.00	178.00	1800.00	11023.90
Ultimate reserves (MMTOE)	773.05	1874.56	730.43	366.78	114.18	69.60	703.84	4310.60
EOR (at 10%) (MMTOE)	197.70	479.40	186.80	93.80	29.20	17.80	180.00	1102.39
Ultimate Reserves after EOR (Mm ³)	1131.29	2743.26	1068.92	536.75	167.09	101.86	1030.01	6308.18
CO ₂ storage capacity (Mt)	658.69	1597.24	667.48	312.52	99.50	67.01	657.25	3402.43

infrastructure incentivizes the operators to save a lot of resources in terms of time and money.

Unarguably, CO₂ EOR is the first step toward geological carbon storage because it eases the financial burden of infrastructure development, which is associated with CO₂ capture, transport, and storage, and because it has been in practice for nearly half a century. In India, financial incentives can play a huge role in the large-scale adoption of investment-heavy projects such as CO₂ storage. India's extreme dependence on imported oil also makes the proposition more attractive. Production has been declining in several of India's producing oil fields, and the oil companies are directed to carry out further exploration activities to meet the domestic oil demand. The wide adoption of a proven technology such as CO₂ EOR in India can help in reviving the dwindling oil production while also storing the greenhouse gases in the subsurface, making it the right step toward a sustainable and energy-secure future. There is a significant potential for storage through CO₂ EOR in India. However, a thorough analysis of the risks involved through detailed basin-wise studies must be carried out to increase confidence in the technology.

5.2. Storage potential in coal formations

As discussed in the previous section, several parameters influence the CO₂ storage capacity of coal reservoirs. However, even with an extensive literature review, it is challenging to find every parameter in all reservoirs. A few empirical equations can be found, which can be used to determine the storage capacity depending on those coal properties that were used for capacity estimations for countries such as the USA, Canada, China, and others. In this study, we used the expressions that were formulated by Kim (Kim, 1977), Ryan (Ryan, 1991), Mavor (Mavor et al., 1994), and Langmuir (Crain, 2011) (Supplementary Table 6):

These equations help in estimating the methane content of a reservoir, which can be further translated into its CO₂ storage capacity through the following expression:

$$Q_{CO_2} = 3V_{gas} \times Q_{coal} \times \rho_{CO_2} \quad (9)$$

where Q_{CO_2} is the mass of the CO₂ that is adsorbed in the coal seam, ρ_{CO_2} is the density of the CO₂, and Q_{coal} is the mass of the coal resource. The ρ_{CO_2} is calculated for each depth interval considering the hydrostatic pressure at the average depths of each interval. The temperature dependent densities for each depth interval is calculated by considering a uniform geothermal gradient of 35°C/km as discussed in section 4.1.

The ratio of CH₄:CO₂ is taken as 1:3 in this study, based on the rank of the coal (bituminous and sub-bituminous) present in India (Vishal et al., 2013b).

By using the equations mentioned in Supplementary Table 6 and the parameters provided in Supplementary Table 7, we have calculated the CO₂ storage capacity of Indian coal reservoirs (Table 3). Similar to Supplementary Table 6, coalfields are subdivided as allocated and unallocated. Because of the inherent approximations and assumptions in the different calculation methods employed in this study, the capacity estimations vary from 3.5 Gt to 6.3 Gt.

Upon close inspection of the equations we can see that Mavor's is the simplest equation, and it only considers ash and moisture contents, whereas Langmuir is dependent on sorption properties, Ryan on the vitrinite reflectance, and Kim depends on the depth and coal composition in general. Kim and Langmuir show very close values, and both of these calculation methods are widely used in industries. These two methods have shown a better match in previous capacity estimations as well (Prabu and Mallick, 2015). Hence, we will consider the values of Kim and Langmuir in further discussions of this study. Based on the results, we have further classified these coalfields into three categories: Very high, high and moderate, as per their CO₂ storage capacity through ECBMR (Fig. 5). Further, the sedimentary basins that correspond to these coalfields were identified and a cumulative storage capacity of

each basin was calculated. It was found that all CBM-bearing coalfields are concentrated in eight sedimentary basins, among which the Satpura–South Rewa–Damodar Basin shows the highest CO₂ storage potential (Fig. 5). Some of the Category-III basins have very weak potential for CO₂ storage; hence, corresponding circles have not been plotted on the map.

5.2.1. Forecast of CO₂ storage capacity in coal seams

The coal resource of India is gradually expanding in line with annual coal production (Fig. 3a). Since 2010, the Indian coal sector has seen a compound annual growth rate (CAGR) (MOC, 2020) of 4.64 %. The annual resource estimation of coal has increased by more than 2 % and will continue to do so. Given such an increase in resource estimates, a similar trend can be predicted up to 2030. A rough growth trendline can be projected based on the current growth rate, which shows a cumulative coal resource of 347.11 Mt by 2025 and 369.6 Mt by 2030 (Fig. 3b). The 319.02 Mt of coal can produce a rough CO₂ storage capacity of 3.5 Gt. Therefore, following that trend, a total coal resource of 347.11 Mt and 369.6 Mt can accommodate approximately 3.81 Gt and 4.02 Gt CO₂, respectively, which is a significant increase in storage capacity. The consideration for this estimation is that an equal increase in coal resource will take place in all coalfields, which will not be the case in reality; hence, the projected estimates may vary slightly in the future.

5.3. Storage potential in saline aquifers

The methodology to calculate the storage potential of saline aquifers in sedimentary basins of India is presented here as a modification of the US DOE method (Goodman et al., 2011). The storage estimates for each of the basins are listed in Table 4. The results incorporate the properties of each of the basins, which are detailed in Supplementary Table 4. The calculations reveal that the total storage capacity is nearly 291 Gt of CO₂. Out of this, Category-I basins have 108.6 Gt, Category-II have 82.75 Gt, and Category-III have a potential capacity of nearly 100 Gt. Most of the capacity of Category-III basins is in the Kerala–Konkan and Bengal basin, with almost half in the latter. Although these basins have not been explored extensively, our results show that they hold substantial storage resources for future exploitation. Category-I basins have the highest capacity, and among these basins, the relatively less explored Assam–Arakan fold belt has the largest potential of more than 30 Gt. Another notable basin is the Saurashtra Basin, which, due to its depth, has a capacity of nearly 40 Gt of storage. A few Category-III basins have been omitted from the study due to insufficient data (Himalayan Foreland Basin, Ganga Basin, Narmada Basin, Spiti–Zaskar, Deccan syncline, Bastar, and Karewa). Fig. 5 shows the results of the current study in the form of the storage capacities of different basins on the map of India.

As a result of the hydrocarbon-focused exploration strategy, the level of detailed data available for the basins is highly skewed toward Category-I basins. This does not imply that they are the best sinks for CO₂ storage, but that they are the most feasible ones due to the availability of detailed data and existing infrastructure. Our analysis (Table 4) shows that there are many other major sedimentary basins in India, which span much larger areas (Category-II and -III) and possibly hold the potential to retain much more CO₂ than Category-I basins. We have defragmented the categorizations and ignored the quality of the available data for each basin, provided sufficient information exists for our estimation. Instead of assuming a constant thickness of aquifers in each basin like previous methodologies (Holloway et al., 2008; IEAGHG, 2009), we have presumed that the thickness of the saline aquifers is directly proportional to the average thickness of the sedimentary basin. From this perspective, the net pore volume available for CO₂ is proportional to the total volume of the sedimentary rocks in a basin, and thus, it becomes a critical parameter that influences the total storage capacity of the basin.

The previous estimates (Holloway et al., 2008; Kearns et al., 2017)

Table 3CO₂ storage capacities of different coal and lignite fields in India

Coalfield	Unit Volume (cc/g)				CO ₂ capacity (TCF)			
	Kim	Ryan	Mavor	Langmuir	Kim	Ryan	Mavor	Langmuir
STORAGE IN COAL RESOURCES								
ALOTTED BLOCKS								
Bokaro	11.8	13.5	12.7	8.4	11.3	12.93	12.17	8.05
North Karanpura	8.8	11.6	10.7	6.4	11.58	15.27	14.08	8.42
Raniganj	11.6	13.4	9.9	11.9	20.46	23.64	17.46	20.99
Sohagpur	6.7	11.4	13.7	4.9	3.78	6.43	7.72	2.76
Sonhat	6.2	12.3	14.2	5.7	1.18	2.34	2.7	1.08
South Karanpura	6.4	11.8	9.61	8.2	3.47	6.4	5.22	4.45
Wardha Valley	4.2	11.3	10.7	6.5	2.28	6.13	5.81	3.53
Birbhum	7.1	11.9	9.3	8.6	3.36	5.62	4.39	4.06
Godavari	5.7	12.7	12.1	7.8	9.44	21.03	20.03	12.91
Mand–Raigarh	4.7	11.1	9.8	6.6	10.11	23.88	21.08	14.2
Rajmahal	5.2	9.4	9.5	4	6.69	12.1	12.22	5.15
Singrauli	3.8	9.4	10.5	3.8	4.2	10.38	11.6	4.2
Tatapani–Ramkola	7.8	12.8	11.7	7.9	1.85	3.03	2.77	1.87
Ib river	3.4	8.3	6.8	3.8	6.79	16.57	13.58	7.59
Talcher	3.6	8.8	6.73	4.5	13.11	32.05	24.51	16.39
Makum	13	11.4	16.14	5.4	0.42	0.37	0.52	0.17
Total CO₂ storage capacity (a) (TCF)					110.02	198.17	175.86	115.8
UNALOTTED BLOCKS								
Barjora	3.35	7.47	9.52	1.52	0.05	0.11	0.14	0.02
Darjeeling	3.07	6.97	10.27	1.35	0	0.01	0.01	0
Jharia	14.01	15.71	11.96	14.8	19.42	21.77	16.58	20.51
Ramgarh	3.62	10.1	12.89	3.66	0.4	1.12	1.42	0.4
Auranga	4.44	11.85	12.89	6.18	0.95	2.53	2.75	1.32
Hutar	3.62	10.1	12.89	3.66	0.06	0.18	0.23	0.07
Daltonganj	3.8	6	13.77	1.19	0.04	0.06	0.14	0.01
Deogarh	5.99	8.02	10.04	1.61	0.17	0.23	0.29	0.05
Johilla	2.63	6.63	12.06	1.25	0.06	0.15	0.28	0.03
Umaria	3.41	7.21	13.2	1.37	0.04	0.09	0.17	0.02
Pench–Kanhana	5.75	10.48	11.36	4.02	1.4	2.56	2.77	0.98
Pathakhera	7.94	10.3	10.72	3.99	0.25	0.33	0.34	0.13
Gurgunda	5.49	7.67	10.72	1.49	0.05	0.08	0.11	0.01
Mohpani	4.04	6.81	13.94	1.3	0	0	0.01	0
Singrauli	3.48	8.4	7.3	3.65	3.85	9.29	8.07	4.04
Jhilimili	3.83	6.81	14.03	1.3	0.07	0.13	0.27	0.02
Chirimiri	3.73	7.91	14.17	1.48	0.1	0.2	0.37	0.04
Bisrampur	3.83	6.81	14.03	1.3	0.53	0.95	1.95	0.18
East of Bisrampur	3.83	6.81	14.03	1.3	0.04	0.08	0.16	0.02
Lakhanpur	2.69	5.04	8.92	0.93	0.09	0.16	0.29	0.03
Panchbahini	2.69	5.04	8.92	0.93	0	0	0.01	0
Hasdo–Arand	3.76	7.64	9.73	2.39	1.48	3.01	3.83	0.94
Sendurgarh	3.09	7.39	12.22	1.4	0.06	0.15	0.24	0.03
Korba	3.14	7.83	8.33	2.72	2.64	6.59	7.01	2.29
Kamptee	3.93	10.65	10.69	5.48	0.86	2.33	2.34	1.2
Umrer–Makardhokra	2.25	6.85	11.08	1.31	0.08	0.23	0.37	0.04
Nand–Bander	2.19	6.68	10.69	1.28	0.17	0.52	0.83	0.1
Bokhara	2.19	6.68	10.69	1.28	0	0.01	0.02	0
Singrimari	7.36	9.39	12.5	1.83	0.01	0.01	0.01	0
Dilli–Jeypore	3.73	3.18	15.83	0.98	0.01	0.01	0.06	0
Namchik–Namphuk	2.17	2.46	10.49	0.16	0.01	0.01	0.06	0
Balphakram–Pendenguru	4.43	3.72	14.59	0.99	0.03	0.03	0.11	0.01
Siju	3.58	5.97	15.8	1.23	0.03	0.05	0.14	0.01
Mawlong–Shella	3.59	4.68	16.21	1.12	0	0	0.01	0
Bapung	6.11	5.75	13.75	1.17	0.01	0.01	0.03	0
Jayanti Hills	7.73	13.68	16.2	1.15	0	0	0	0
West Darangiri	4.15	15.75	18.08	1.17	0.04	0.14	0.16	0.01
East Darangiri	4.15	15.75	18.08	1.17	0.01	0.04	0.04	0
Langrin	4.83	15.01	17.86	1.17	0.05	0.14	0.17	0.01
Khasi Hills	8.64	16.68	14.13	1.17	0.01	0.01	0.01	0
Borjan	5.03	13.96	11.72	1.13	0	0.01	0.01	0
Jhanzi–Disai	3.42	14.26	15.27	1.13	0.02	0.1	0.11	0.01
Tuen Sang	3.42	14.26	15.27	1.13	0	0	0	0
Tiru Valley	3.8	15.46	17.63	1.17	0	0.01	0.01	0
Total CO₂ storage capacity (b) (TCF)					33.13	53.45	51.93	32.54
Total CO₂ storage capacity (a+b) (TCF)					143.15	251.62	227.79	148.34
Total CO₂ storage capacity (a+b) (Gt)					3.5	6.3	5.7	3.7
STORAGE IN LIGNITE RESOURCES								
Pondicherry	0.28	3.82	13.16	0.49	0.01	0.11	0.39	0.01
Tamilnadu	0.56	6.62	13.16	1.30	1.44	17.02	33.84	3.34
Rajasthan	0.57	6.46	11.39	2.18	0.26	2.92	5.15	0.99
Gujarat	0.83	5.49	13.99	1.21	0.16	1.06	2.71	0.23
Jammu and Kashmir	0.27	3.33	6.47	0.43	0.00	0.01	0.01	0.00

(continued on next page)

Table 3 (continued)

Coalfield	Unit Volume (cc/g)				CO ₂ capacity (TCF)			
	Kim	Ryan	Mavor	Langmuir	Kim	Ryan	Mavor	Langmuir
Kerala	0.37	3.47	9.93	0.43	0.00	0.00	0.01	0.00
West Bengal	0.83	5.49	13.99	1.21	0.00	0.00	0.00	0.00
CO ₂ capacity in Lignite (TCF)					1.87	21.13	42.11	4.58

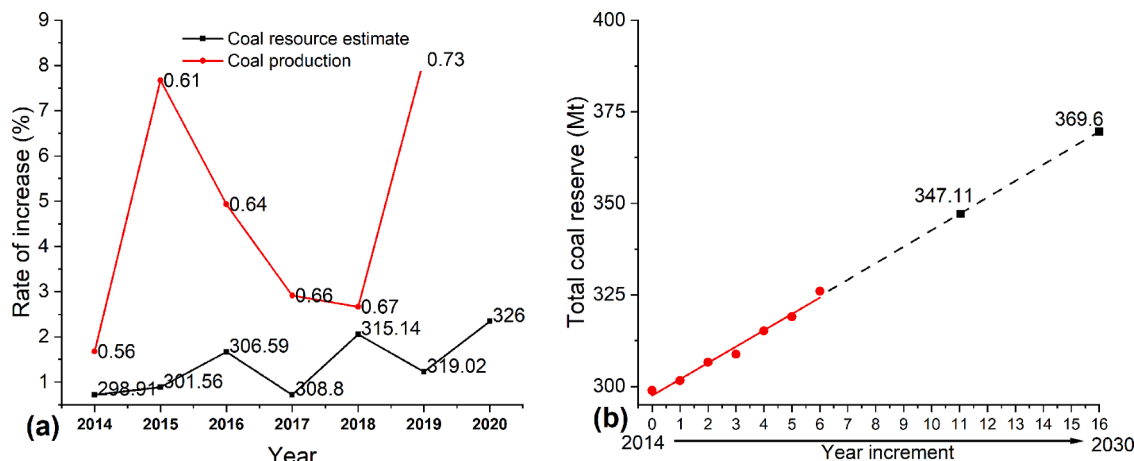


Fig. 3. (a) Rate of increase in coal resource and coal mining in India (2014–2020). (b) A forecast of coal resources for the next 10 years (until 2030).

Table 4

Total and basin-wise estimates of storage capacities in Indian saline aquifers

S. No.	Sedimentary Basins	Classification	Dominant Lithology	Volume (km ³)	Efficiency Coefficient	CO ₂ storage capacity (Gt)
Category-I Basins						108.66
1.	Krishna–Godavari	Median	Sandstone	6,900.00	0.020	13.39
2.	Mumbai Offshore	Median	Limestone	6,360.00	0.015	9.26
3.	Assam Shelf	Deep	Sandstone	2,520.00	0.054	14.16
4.	Rajasthan	Median	Sandstone	3,780.00	0.020	7.34
5.	Cauvery	Median	Shale	8,100.00	0.020	16.08
6.	Assam–Arakan Fold Belt	Deep	Sandstone	5,455.69	0.054	32.30
7.	Cambay	Deep	Sandstone	2,808.75	0.054	16.13
Category-II Basins						82.75
8.	Saurashtra	Deep	Sandstone	7,279.28	0.054	39.74
9.	Kutch	Deep	Sandstone	2,634.93	0.054	15.60
10.	Vindhyan	Median	Sandstone	6,086.64	0.020	11.81
11.	Mahanadi–NEC (North East Coast)	Median	Sandstone	1,865.63	0.020	3.25
12.	Andaman–Nicobar	Median	Sandstone	6,777.54	0.020	12.35
Category-III Basins						99.68
13.	Kerala–Konkan–Lakshadweep	Median	Limestone	17,400.00	0.015	25.33
14.	Bengal–Purnea	Deep	Sandstone	8,234.60	0.054	51.58
15.	Ganga–Punjab	-	Sandstone	-	0.020	-
16.	Pranhita–Godavari	Deep	Sandstone	1,125.00	0.054	6.14
17.	Satpura–South Rewa–Damodar	Median	Sandstone	1,072.13	0.020	1.87
18.	Himalayan Foreland	-	-	-	-	-
19.	Chhattisgarh	Shallow	Carbonates	360.00	0.004	0.11
20.	Narmada	-	-	-	-	-
21.	Spiti–Zaskar	-	-	-	-	-
22.	Deccan Syncline	-	-	-	-	-
23.	Cuddapah	Deep	Sandstone	2,406.00	0.054	14.24
24.	Karewa	-	-	-	-	-
25.	Bhima–Kaladgi	Median	Sandstone	217.88	0.020	0.41
26.	Bastar	-	-	-	-	-
India (Total)						291.09

assumed that the storage capacity of a sedimentary basin depended on its area, and they overlooked other important factors such as the basin's geology, depth, temperature, and so on. This led to an oversimplification of the capacity calculations. Our study incorporates both the areal extent and the thickness of the sediments, which ultimately makes this analysis dependent on the volume of the sedimentary rocks in the basin as opposed to merely the area. Additionally, the capacity of a given reservoir to store CO₂ is largely attributed to the reservoir rock's

petrophysical properties such as porosity and permeability as well as in situ conditions of pressure and temperature in the basin (Kopp et al., 2009b). The petrophysical properties of sedimentary rocks are significantly influenced by the rock type, as well as the depth of the formation. Therefore, storage efficiency calculations must consider both. Furthermore, there are direct links between simulated storage efficiencies (which incorporate the reservoir properties) and the lithology of the formation (Goodman et al., 2011; IEA, 2013). The current study, thus,

emphasizes the dominant lithology as well as the average depth of each basin in order to assign the respective storage efficiency coefficients. Weighted averages of coefficients would have provided more precise capacity values, but due to the unavailability of detailed data, such a treatment is not feasible at this stage. The density values of CO₂ have also been adjusted corresponding to the average depth, pressure, and temperature conditions in the basin instead of assuming a single constant value. Therefore, the current estimates reflect a more accurate picture of the subsurface capacity.

Storage estimates are the most reliable when they are calculated for reservoirs with known thicknesses and areal extent along with a detailed geological characterization of the site. Several constraints control the accurate assessment of the CO₂ storage capacity of a reservoir. Upstream constraints include the presence of impermeable caprock, which seals the formation; stratigraphic or structural closures; consideration of offshore storage; source-sink matching, which occludes those sinks that are away from sources; and a suitable depth to ensure supercritical or dense liquid storage (Heidug, 2013). Downstream constraints consider the reservoir pressure (low enough for the reservoir to accommodate the rise in pressure due to CO₂ injection) and the amount of total dissolved solids (TDS) to exclude potable water reserves. The injection rate can also alter the total capacity of the formation (De Silva and Ranjith, 2012; Gorecki et al., 2009b), but it has to be considered in the planning stage and cannot be incorporated into the feasibility and assessment stages. These factors should play a role in reducing the theoretical capacity to obtain better evaluations of effective and viable capacities. However, data on such factors are not readily available. Consequently, such a treatment is impossible in Indian basins according to their current exploration status. There has never been an initiative to acquire deep saline aquifer data since the injection of waste materials is not an industrial practice in India yet, and the petroleum industry has not taken an interest in saline aquifers. Therefore, the calculation of a nationwide estimate to a high level of detail is not viable at this stage. Future studies should focus on gathering detailed data for the characterization of saline formations to obtain more accurate results. Meanwhile, the best approach is to base our calculation on the assumption that the distribution of saline aquifers and the associated storage potential is uniform across the basins, irrespective of their current state of exploration. The exact amount of storage is difficult to quantify, but it is likely that a basin with a higher sediment volume has proportionally more saline aquifer storage capacity.

5.3.1. Classification of basins based on storage prospect

The classification of basins based on their exploration maturity is a very robust one when selecting a basin for CO₂ storage. The extent of data available and the existing infrastructure that the oil companies have built through decades of exploration and production (E&P) provide the operator with significant confidence. However, the grouping of Indian sedimentary basins by DGH (DGH, 2020) into Category-I, -II, and -III (Reserves, Contingent Resources, and Prospective Resources) does not account for the total CO₂ storage capacity of the respective basins. In the long term, the categorization of the basins based only on their hydrocarbon potential will prove less useful because the data available are focused on the petroleum system and not on the saline aquifers in the basin. The oversight is expected because Indian basins have not yet been surveyed bearing CO₂ storage in mind, and only rough storage capacity estimates are available. Hence, we devised a new classification based on the 'storage prospectivity' of large-scale projects by incorporating the total estimated storage capacity and the exploration maturity or the storage feasibility of the basins. Category-I basins, due to their history of extensive exploration and production, have been assumed to have the highest feasibility for storage, followed by Category-II and Category-III basins. This divides the nineteen basins evaluated in our study into four groups: basins with very high potential, high potential, moderate potential, and low potential. Fig. 4 shows the categorizations of the different basins.

Based on the classification, five Category-I basins offer very high potential, while Rajasthan and Mumbai Offshore Basin offer high potential in terms of storage prospectivity. Except for Mahanadi Basin, all Category-II basins show moderate potential along with Bengal, Kerala-Konkan, and Cuddappah Basin from Category-III. The rest of the Category-III basins show low potential due to minimal storage capacity. Table 5 lists the different sedimentary basins classified on the basis of storage prospectivity.

5.4. Storage potential in basalt

Basalts offer the potential for long-term safe CO₂ sequestration through multiple physical and chemical trapping mechanisms. Their main advantage is that they enable rapid mineral trapping, which involves geochemical reactions with basalt that allow CO₂ to form stable carbonate minerals. The abundance of basalts on the earth's surface is another reason for storage in basalt being considered as a serious alternative to other forms of storage. India has a sizable areal presence of

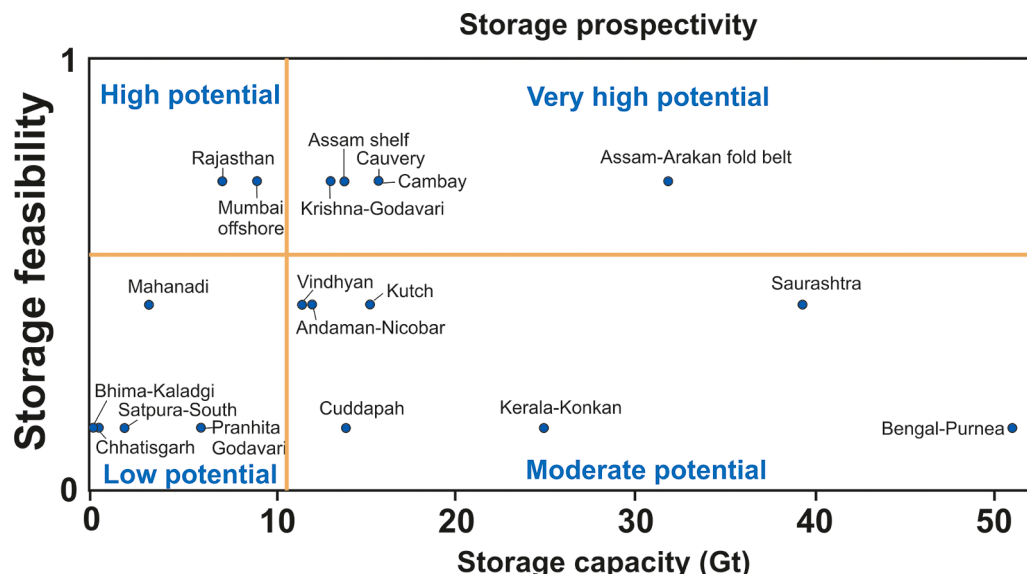


Fig. 4. Classification of the sedimentary basins of India based on Storage Prospectivity.

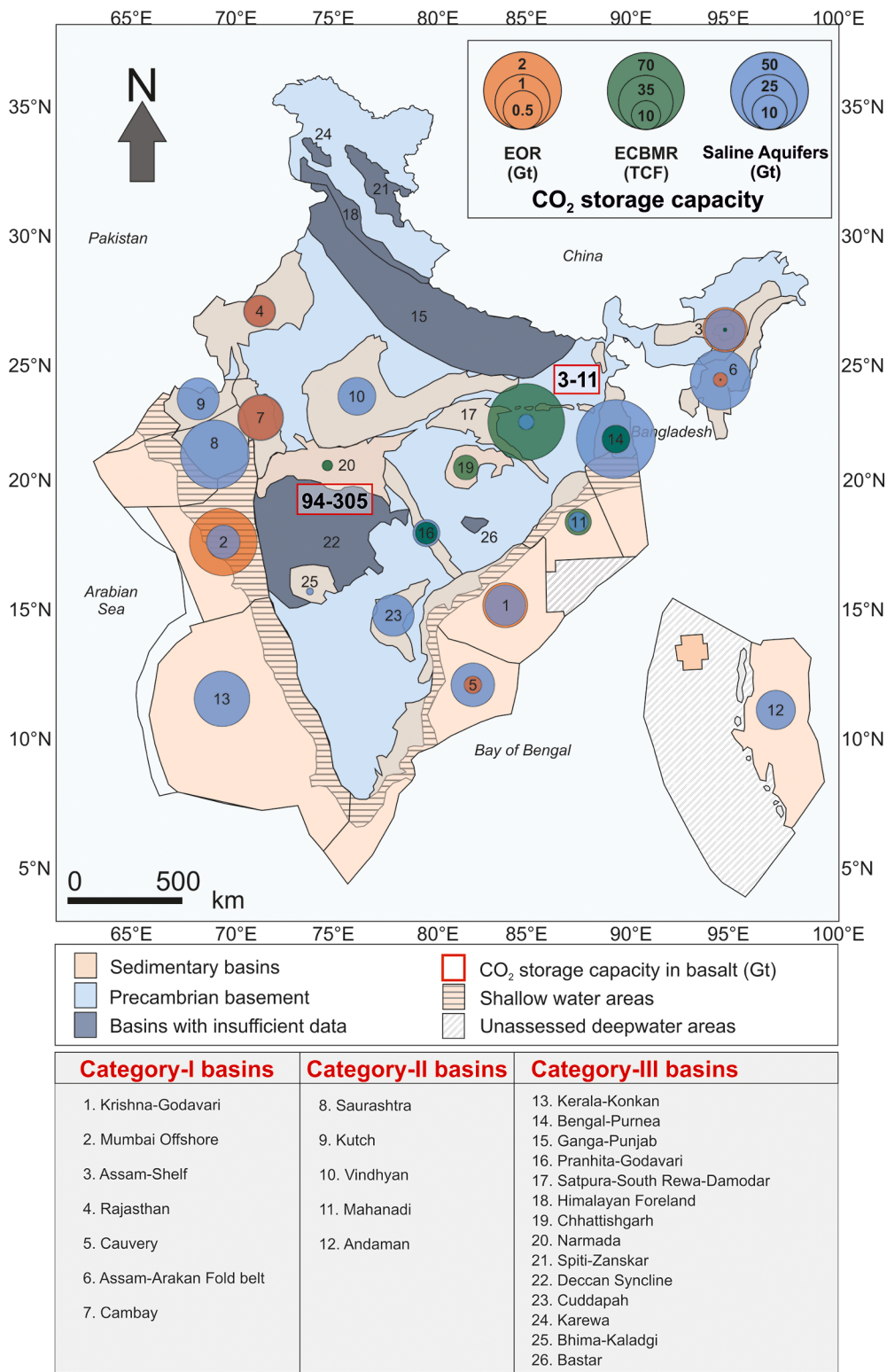


Fig. 5. Major sedimentary basins in India, showing CO₂ storage potential through CO₂ EOR, ECBMR, in saline aquifers, and in basalt. The area of the circles represents the relative capacities of the basins, and the storage capacity range in basalts have been marked in a red box. The basins corresponding to the numbers (1–26) are mentioned in the legend. The basins marked in gray have been omitted from this study due to availability of limited data (after DGH, 2017).

basalt too. The Deccan Volcanic Province (DVP) is one of the most massive terrestrial flood basalt formations, and it covers nearly 500,000 km² in west-central India (Eldholm and Coffin, 2000; Tiwari et al., 2001). The volume of Deccan basalt is estimated to be 512,000 km³. In addition to the DVP, a smaller basalt formation in east India, the Rajmahal trap, consists of basalt that is 450 to 600 m thick and covers an

area of approximately 18,000 km² (McGrail et al., 2006). Both of these geological units represent great storage potential in India. Singh et al. (2006) estimated a total of 200 Gt of CO₂ storage capacity in Indian basalts. Holloway et al. (2008) did not consider sequestration in basalt, given that the technology had not matured enough at the time to play a significant role in the total capacity in India. In view of the

Table 5

List of Indian sedimentary basins classified on the basis of their Storage Prospectivity.

Classification	Storage Prospectivity	Basins
Class I	Very high potential	Assam–Arakan Cambay Cauvery Assam shelf Krishna–Godavari
Class II	High potential	Mumbai Offshore Rajasthan
Class III	Moderate Potential	Bengal–Purnea Saurashtra Kerala–Konkan Kutch Andaman Nicobar Vindhyan Cuddapah
Class IV	Low Potential	Mahanadi Pranhita–Godavari Satpura–South Rewa–Damodar Chhattisgarh Rewa Damodar

advancements in research in basalt storage since then (Gislason and Oelkers, 2014; Parisio and Vilarrasa, 2020; Snæbjörnsdóttir et al., 2020), we have included the storage capacity of basalts in our estimation. We have used two methods (McGrail et al., 2006; Snæbjörnsdóttir et al., 2014) for estimating the storage capacity in India, which incorporate different values of storage per unit volume, and net pore volume calculations (Table 6). The total CO₂ storage capacity is then calculated through the following equation:

$$G_{CO_2} = Ah\phi E_{CO_2} \quad (10)$$

where G_{CO_2} is the total CO₂ storage potential, A is the area covered by the basalt formation, h is the effective net thickness of the formations, ϕ is the average porosity, and E_{CO_2} is the storage efficiency or the CO₂ storage per unit pore volume. In the Snæbjörnsdóttir et al. (2014) method, the storage per unit volume from the Reykjanes system provides the lower limit of 18.8 kg/m³, while the upper limit is obtained from the Krafla system equal to 48.7 kg/m³. The McGrail et al. (2006) methodology assumes a storage efficiency of 40.65 kg/m³. Our calculations indicate that the total basalt storage capacity in India lies in the range of 97–316 Gt of CO₂ (Table 6), most of which is provided by the DVP (94–315 Gt) and a small amount by the Rajmahal traps (3–11 Gt).

The range of estimates of storage potential obtained in the current study is in line with estimates obtained for different areas around the world (Goldberg and Slagle, 2009). The storage potential of 93,000 km² area of offshore Iceland is estimated to be at least 60 Gt and up to 7000 Gt (Anthonson et al., 2013; Callow et al., 2018; Snæbjörnsdóttir and Gislason, 2016). Goldberg et al. (2008) estimated that 750–900 Gt of CO₂ could be mineralized in the Juan de Fuca plate in USA, which covers approximately 78,000 km² of area. McGrail et al. (2006) estimated more than 100 Gt of storage potential in Columbian River Basalts in USA, covering 164,000 km² of area. Moreover, the amount of CO₂

Table 6

CO₂ storage capacity in basalts in India based on different methodologies

Methodology	Snæbjörnsdóttir et al. (2014)		McGrail et al. (2006)
	Low	High	
Net thickness (m)	100	100	100
Porosity	0.1	0.1	0.15
Storage Efficiency (kg/m ³)	18.8	48.7	40.65
CO ₂ storage capacity (Gt)			
DVP (500,000 km ²)	94.00	243.50	304.88
Rajmahal Traps (18000 km ²)	3.38	8.77	10.98
Total (518,000 km ²)	97.38	252.27	315.85

mineralized in the active geothermal systems of Iceland, which cover less than 1 km² of area, is measured to be in the range of 30–40 Gt (Weise et al., 2008). Given the considerably larger volume of Indian basalts compared to these areas, the estimated range of 97–316 Gt of CO₂ storage capacity can be deemed a conservative theoretical estimate.

The global storage capacities in basalts have been estimated to be in the range of 8000–41000 Gt of CO₂ (Goldberg and Slagle, 2009). Moreover, two ongoing projects—the CarbFix project in Iceland (Gislason et al., 2018) and the Wallula Basalt pilot test by the Big Sky Carbon Sequestration Partnership (McGrail et al., 2011) in the United States—are studying the viability of CO₂ storage in basalt. In the CarbFix project, more than 95 % of injected CO₂ was trapped in carbonates within a span of two years (Matter et al., 2016), and more than 1000 tons of CO₂ were successfully injected in the Wallula pilot test (McGrail et al., 2017). The initial success of the projects suggests that basalt sequestrations can provide an efficient pathway to storing CO₂ in the ground permanently and offset our carbon emissions considerably in the long term.

6. Conclusion

We have presented detailed methodologies to estimate the geologic storage potential for carbon dioxide in the context of India. The storage potential is estimated through four different pathways: storage through CO₂ EOR, ECBMR, in deep saline aquifers, and basalts. Our analysis attempts to provide a reasonable approximation of the storage capacities through these media by gathering the most relevant data (areal extent, effective thickness, depth, and such others), utilizing them to assign storage efficiency coefficients, and deriving the amount of storage by using appropriate equations. Through this, we have attempted to provide updated estimates of theoretical capacities and have calculated novel effective capacities for various basins in India.

From our analysis, the total storage capacity for India ranges between 395 – 614 Gt of CO₂, which is distributed among storage in oil fields (3.4 Gt), coal formations (3.7 Gt), deep saline aquifers (291 Gt), and basalts (97–316 Gt). For storage in oil fields, only discovered resources from Category-I (commercially established and producing) basins have been considered, while resources from Category-II (contingent resources) and Category-III (prospective resources) basins have been ignored. Meanwhile, storage in deep saline aquifers is analyzed for all three categories of basins, and the capacities obtained are almost uniformly distributed with slight variations. Category-I basins have the highest capacity (108.6 Gt), followed by Category III (100 Gt) and Category-II (83 Gt) basins. However, the categories defined here are based on their hydrocarbon recovery potential. An array of comprehensive parametric models used to calculate the CO₂ storage potential in coal seams across India reveal that a significant fraction of the total storage capacity lies in the 16 coal blocks for CBM exploration (2.68–4.83 Gt) allocated by DGH, whereas the unallocated blocks have lesser storage potential (0.8–1.3 Gt), which totals to a cumulative 3.7 Gt CO₂ storage potential. However, the local heterogeneity of the coal seams could not be considered because of limited availability of data. In order to analyze the “prospectivity” of the basins for carbon storage, we have developed a novel classification of the basins by considering both their storage feasibility and capacity. Storage feasibility refers to the readiness of basins to implement storage projects based on the availability of infrastructure and geological characterization. Based on this metric, the basins are divided into four classes: very high potential, high potential, medium, and low potential. Storage capacity in basalt is almost entirely concentrated in the Deccan Volcanic Province.

The challenges faced in this study were mainly caused by the lack of complete data across all potential reservoirs in India, which can result in over/underestimation of CO₂ storage capacity. Additionally, the lack of focused research on CO₂ storage specific to Indian geology imposed certain assumptions in different calculations. Even so, overall, the results indicate enormous storage potential in Indian basins. However,

CO₂ storage is still unfamiliar territory for India. To rectify it, there has been a push to develop India's CCS capabilities through the selection of potential EOR and ECBMR sites. The current study is intended to aid the identification of additional sites around the country and facilitate detailed feasibility studies for CO₂ storage. The estimations provided in our study will help identify priority focus areas and act as a yardstick for future research and detailed reservoir-specific capacity estimations. Moreover, the improved capacity estimates can assist stakeholders in their decision-making process and help expedite large-scale pilot storage projects that are required to meet our climate change mitigation goals.

Credit authorship contribution statement

Vikram Vishal: Conceptualization, Methodology, Validation, Formal analysis, Resources, Writing - review & editing, Supervision, Project administration, Funding acquisition.

Yashvardhan Verma: Conceptualization, Methodology, Validation, Formal analysis, Investigation, Visualization, Writing - original draft.

Debanjan Chandra: Methodology, Validation, Formal analysis, Investigation, Visualization, Writing - original draft.

Dhananjayan Ashok: Methodology, Investigation, Writing - original draft.

Declaration of Competing Interest

The authors declare no competing interest.

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Supplementary materials

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