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Meeting the challenges of large-scale carbon storage and hydrogen production

Mark Zoback[a,1] and Dirk Smit[b]

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There is a pressing need to rapidly, and massively, scale up negative carbon strategies such as carbon capture and storage (CCS). At the same time, large-scale CCS can enable ramp-up of large-scale hydrogen production, a key component of decarbonized energy systems. We argue here that the safest, and most practical strategy for dramatically increasing CO_2 storage in the subsurface is to focus on regions where there are multiple partially depleted oil and gas reservoirs. Many of these reservoirs have adequate storage capacity, are geologically and hydrodynamically well understood and are less prone to injection-induced seismicity than saline aquifers. Once a CO_2 storage facility is up and running, it can be used to store CO_2 from multiple sources. Integration of CCS with hydrogen production appears to be an economically viable strategy for dramatically reducing greenhouse gas emissions over the next decade, particularly in oil- and gas-producing countries where there are numerous depleted reservoirs that are potentially suitable for large-scale carbon storage.

energy transition | hydrogen | CO_2 storage

The Critical Needs for Large-Scale Carbon Capture and Storage (CCS) and Hydrogen Production

It has long been recognized that carbon capture and storage (CCS) in geologic formations is a critical component of decarbonization strategies to limit global warming (1). Recent studies have emphasized the enormous scale at which CCS activities must be undertaken, in a very short period of time, to be a critical component of greenhouse gas (GHG) emission reduction strategies (2). For example, the International Energy Agency estimates that about 1 GT CO_2/y needs to be stored in the subsurface by 2030 and about 6 GT CO_2/y by 2050. Recent years have seen a marked increase in the number of potential CCS facilities around the world, including more than 75 new facilities that are in early stages of planning (3). If all of these facilities were to be fully operational by 2030, the cumulative storage capacity would be about 244 MT CO_2/y (3), well short of the goal of storing 1 GT/y of anthropogenic CO_2 by 2030. Moreover, about half the CO_2 currently being stored at the 30 currently operational facilities comes from anthropogenic sources, and half is CO_2 that is being coproduced with natural gas. CO_2 is a supercritical fluid under reservoir conditions with a density of about 600 kg/m^3. 1 GT of supercritical CO_2 occupies about 1.3 billion m^3 of pore space in the subsurface. Thus, the longer term goal of storing 6 GT CO_2/y by 2050 is equivalent to storing a volume of fluid roughly 50% more than all the oil produced, transported, and consumed in 2020. Without question, dramatic acceleration of CO_2 storage needs to be undertaken in the next couple of decades if it is to play a critical role in limiting global warming.

To meet such ambitious goals for CCS, three critical issues need to be addressed. The first aspect is scale—how and where in the subsurface can we start storing enormous volumes of CCS in the next few years? Second is safety—how can we inject and store enormous quantities of CO_2 into the subsurface without injection-related pressure increases inducing earthquakes or causing other potentially harmful environmental impacts? The third issue is economics—how do we add value to large-scale CCS so it is not entirely dependent on government subsidies to be economically viable? Economic viability is crucial as hundreds of CCS projects are going to be needed at many sites around the world. While government-funded incentives have been critical in advancing research related to investigating the viability of CCS (4, 5) and accelerating both CCS and hydrogen production in the United States, the point of this paper is to consider an economic and technically viable strategy to significantly ramp up CCS activities in the next decade almost anywhere in the world where oil and gas are currently being produced.

We argue here that hydrogen production, paired with CCS, can be a robust strategy to significantly advance society's drive toward net zero while satisfying the three constraints of scale, safety, and economic viability. It is not the goal of this paper to review all pathways to decarbonization, but rather to point out the attributes of a single pathway that can operate at the requisite scale. To meet global decarbonization goals by mid-century, it is likely that there will need to be hundreds of low-to-no carbon technologies implemented at thousands of sites around the world.

It is widely accepted that hydrogen is a critical part of pathways to a net zero energy system. Hydrogen can be used

Author affiliations: [a]Geophysics Emeritus at Stanford University, Stanford, CA 94305; and [b]Shell Global Solutions International, Grasweg 31, 1031 HW Amsterdam, Netherlands

Author contributions: M.Z. and D.S. analyzed data; and wrote the paper.

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[1]To whom correspondence may be addressed. Email: zoback@stanford.edu.

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in fuel cells to power heavy duty vehicles, hydrogen-based synfuels could be used in aviation, hydrogen can be burned cleanly for heat in a wide variety of industrial processes as well as electrical power generation, and hydrogen is a critical feedstock for the chemical industry and ammonia-based fertilizers. Hence, the availability of large amounts of competitively priced hydrogen will enable many decarbonization processes from transport to heavy manufacturing industries. As shown in Fig. 1 (modified from ref. 6), hydrogen use is expected to double by 2040 and triple by 2060, with significant increases in hydrogen use expected for transportation, industrial use, synfuels, and ammonia production.

Hydrogen can be produced through electrolysis, using electricity to separate hydrogen from oxygen in water (H_20) or using natural gas and separating hydrogen from carbon in methane (CH_4). Electrolysis is often referred to as "green" hydrogen when the electricity is provided from renewable sources like the wind and sun. Most hydrogen today is produced (>99% in the United States) from natural gas using steam methane reforming (SMR) or autothermal reforming (ATR). If SMR or ATR is combined with CCS, it is commonly referred to as "blue" hydrogen. However, if the methane comes from a distribution system with excessive leakage, it could obviate the climate benefits of blue hydrogen. Thus, a prerequisite for blue hydrogen to be successful in reducing GHG emissions, blue hydrogen projects need to utilize responsibly sourced gas that certifies that the methane feedstock was produced from wells that were properly constructed and distributed via pipelines and infrastructure with minimal leakage. Of course, in many cases new and/or repurposed infrastructure will be utilized specifically to prevent methane leakage. In this case, blue hydrogen production can have comparable climate impacts as green hydrogen (7, 8).

While electrolysis using renewable electricity obviates the need for CCS, the current cost of hydrogen produced from carbon-free sources such as the wind and sun ranges from three to seven times that of producing hydrogen from SMR or ATR (7–10). While electricity costs from renewable sources will eventually come down, electricity costs around the world have been increasing sharply in recent years due to the demands for increased electrical power generation and the need for new grid infrastructure. Both will constrain fast ramp-up of hydrogen production from renewable sources. This is particularly true in areas where base manufacturing industries are likely to grow, for example in Asia and the developing world. Still another consideration is that the competition for renewable energy in many other applications limits its availability for green hydrogen (7).

Still another challenge for producing green hydrogen is the land use, infrastructure development, and the deployment time required for wind and solar deployment to provide amount of energy comparable to current fossil fuel use. Using the assumptions shown in Table 1, Fig. 2 shows the area required for hydrogen produced by the wind and sun to replace the amount of energy provided by oil in the United Kingdom and Japan (modified from ref. 11).

It is obvious in Fig. 2 that enormous areas are required for the wind and sun to produce the required amount of electricity needed to produce enough hydrogen to replace oil in the United Kingdom and Japan. In fact, even if both the cost of electricity from the wind and sun and the amount of energy per km^2 required dramatically decreased in the foreseeable future, achieving such large-scale deployments of renewable infrastructure will be a formidable obstacle to rapid deployment.

Alternatively, steam methane reforming (SMR) or autothermal reforming (ATR) can be combined with CCS to produce near carbon-free hydrogen. ATR has several advantages including the fact that there is a more concentrated CO_2 stream than SMR as there is no need for postcombustion capture from flue gas, as there is in SMR. Carbon capture in ATR systems could achieve over 95% of the CO_2 produced without flue gas capture but could be over 90% from SMR systems if flue gas capture is included (7, 8). Another advantage of ATR over SMR is an exothermic reaction; ATR does not require the use of supplemental methane for combustion.

It is critical in reduced fugitive methane emissions associated with methane production and distribution. International

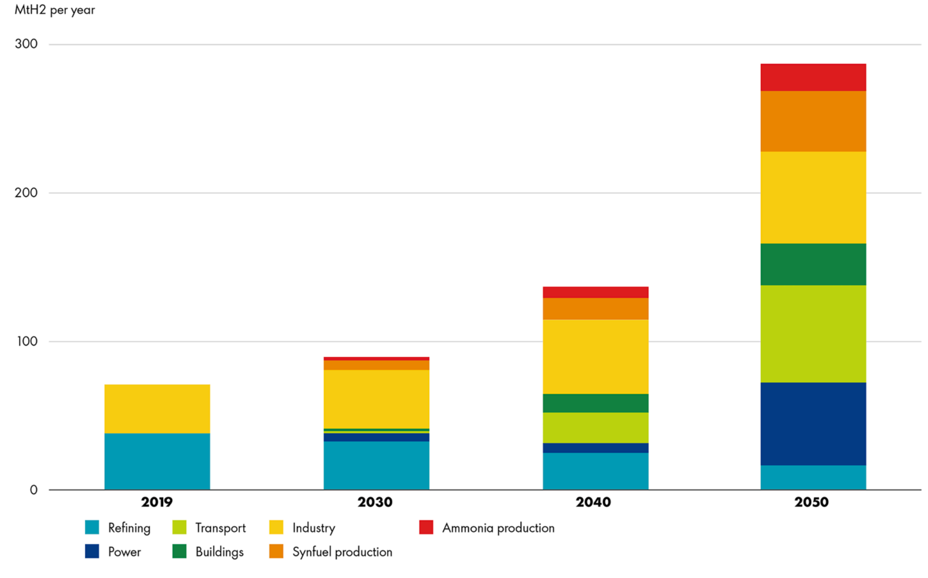

Fig. 1. Anticipated growth in hydrogen demand through 2060 (6). The colors refer to the demand from different industrial sectors.

Table 1. Area required to produce wind or solar energy to produce sufficient hydrogen to replace oil in Japan or the United Kingdom (11)

	Solar PV	Offshore Wind
Power density (MW/km^2)	50	2.3
Capacity factor	12%	50%
Specific annual energy production (GWh/km^2/year)	52.6	9.1
Specific annual hydrogen production ($Tonnes/km^2$/year)	968	167

	United Kingdom	Japan
Oil consumption (Exajoules)	3.11	7.53
Annual hydrogen production (Tonnes)	25.5×10^6	62.7×10^6
Solar PV for hydrogen production (MWe)	1.30×10^6	3.16×10^6
Area of solar PV for hydrogen production (km^2)	26,090	63,170
Offshore wind for hydrogen production (MWe)	313,070	842,240
Area of offshore wind for hydrogen production (km^2)	136,120	366,190

standards should be developed to accomplish this. ATR and SMR produce hydrogen from methane at about \$1.48/kg and \$2.27/kg, respectively, including the cost of CCS (9). Under optimal circumstances, blue hydrogen produced with ATR with CCS can produce life-cycle emissions comparable to green hydrogen produced with solar energy (7). This said, producing hydrogen from ATR and SMR produces approximately 10 kg of CO_2 for every kg of hydrogen, thus increasing the need for CCS by about another 2 GT per year by 2050.

Ramping up clean hydrogen production quickly may help accelerate decarbonization of hard-to-abate base manufacturing industries (such as steel, cement, ammonia, and polyethylene production) as it would allow these industries to switch to near-zero carbon hydrogen much earlier than what could eventually be achieved with renewable electricity. Energy use with base manufacturing accounts for 25% of all GHG emissions and is likely to grow over the next few decades—mainly in Asia. Hence, the ability to accelerate decarbonization of these industries will be crucial to meet the Paris climate goals.

The Challenges of Large-Scale Geologic Storage

Rapidly scaling up CCS will require many CO_2 storage opportunities that can be efficiently assessed for their practical suitability, with minimal health safety and environmental risks. There are two realistic options for geologic storage of large volumes of CO_2 in the subsurface: mature, partially depleted oil and gas reservoirs, and saline aquifers—permeable formations filled with water that is so saline that it cannot be used for either consumption or irrigation. Other options are less likely to provide realistic solutions. For example, while it is possible to inject and store CO_2 into fractured basaltic rock or coal beds (where the CO_2 could be held in place by adsorption), it requires higher costs and detailed characterization, and the ability to scale up has not yet been demonstrated. Another technique, the use of CO_2 to enhance oil recovery (EOR) recycles much of the injected CO_2 but a significant amount of CO_2 stays behind, replacing the produced oil. Oil produced by EOR can result in lower CO_2 emissions than conventionally produced oil (12), but

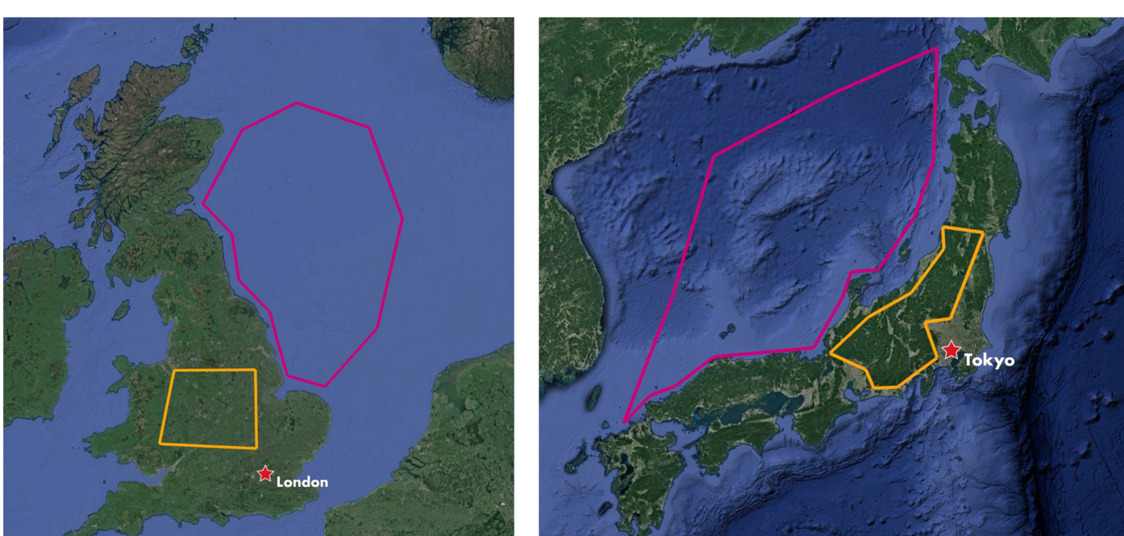

Fig. 2. Land use requirements for solar (yellow) or offshore wind (red) to generate sufficient energy to replace oil use in the United Kingdom (*Left*) and Japan (*Right*) (11).

costs more to produce, and is seen by some as a strategy for perpetuating the use of fossil fuels. We will therefore focus our discussion on storing CO_2 in mature oil and gas reservoirs and saline aquifers.

Saline aquifers are found throughout most continental interiors and a number of offshore areas. Most of the relatively small-scale CCS projects operating around the world utilize saline aquifers for storage. If one were to assume that the volume of accessible pore space in these reservoirs was equivalent to storage capacity, there would appear to be an almost unlimited capacity for carbon storage in North America (13). While this would seem to satisfy the requirement of having many storage opportunities, the great majority of saline aquifers have not yet been adequately characterized. The Society of Petroleum Engineers has developed a framework for estimating the capacity of proposed carbon storage facilities (the Storage Resource Management System), yet an extremely small fraction of the potentially available pore space has been characterized to date (3, 14), which is far below what is needed for gigaton scale CCS. Moreover, taking into account that neither the flow properties of prospective reservoirs nor their geomechanical state have been evaluated, estimates of storage capacity of saline aquifers in North America based on pore volumes are clearly inadequate.

Thus, although saline aquifers are a viable option for CO_2 storage, this option, like any other storage option, requires significant site characterization, a time-consuming and costly process with no guarantee that any given site being investigated will prove to be viable. A recent study of assessing CO_2 storage opportunities in California (15) illustrates procedures for screening potential storage sites considering both geologic and land-use constraints (population density, proximity to habitat, etc.) as well as the complexities (and immaturity) of existing regulatory procedures. Once potential sites have been identified, evaluation of a potential saline aquifer for carbon storage is similar to evaluation of a potential oil and gas reservoir—3D seismic data are required to map and characterize the subsurface as well as to identify possible leakage pathways (such as preexisting faults). In this regard, many of the saline aquifers in the Gulf of Mexico region of the United States have been relatively well characterized during oil and gas exploration activities. Still, this information needs to be augmented by obtaining core samples for laboratory studies of the composition, porosity, permeability, and physical properties of the potential storage formations as well as the sealing formations. Once formation properties are known, modeling needs to be done to assess storage capacity and optimal injection strategies, long-term monitoring programs need to be devised, and contingency plans need to be developed. One general problem encountered when using saline aquifers for CO_2 storage is the lack of understanding about how such systems would respond to injection of large volumes of CO_2. Experience in the oil and gas industry shows that production and injection of fluids at large scale often takes years to understand.

One of the most important hazards associated with injection of CO_2 into saline aquifers is the risk of triggering earthquakes. Public opinion in response to the occurrence of induced small earthquakes resulted in stopping gas production from the Groningen field in The Netherlands and hydraulic fracturing operations in the United Kingdom. Therefore, evaluating saline aquifers at a large scale will require significant data acquisition and analysis in formations in which there is very little current knowledge about injection risks. The potential for injection of CO_2 into saline aquifers to induce seismicity was pointed out a decade ago (16). While the potential for induced seismicity resulting from injection in weak, poorly cemented sediments as found in the Gulf of Mexico is quite low, this is not the general case for saline aquifers in continental interiors. Clear evidence of this is the numerous cases of injection-induced seismicity over the past 10 to 15 y in the United States and Canada due to greatly increased produced water injection associated with production from several hundred thousand unconventional oil and gas wells drilled into relatively impermeable shale formations. The great majority of cases of induced seismicity were not caused by hydraulic fracturing (as is widely believed) but were caused by small pressure increases resulting from injection of produced water into saline aquifers, an analogous process to injection of supercritical CO_2 (17). If CO_2 injection is associated with triggering earthquakes, it would likely be perceived by the public as a hazardous activity, which should be stopped. Two recent cases of injection-induced seismicity are particularly relevant to the feasibility of large-scale CO_2 sequestration in saline aquifers. In both cases, significant seismicity was triggered by very small pressure changes. Current regulations related to CO_2 injection limit pressure changes in saline aquifers to not exceeding 90% of the pressure required to hydraulically fracture the cap rock. In the two cases discussed below, seismicity is resulting from pressure increases that are one to two orders-of-magnitude lower than the regulatory limit, thus severely limiting the volume and rate of possible CO_2 injection into saline aquifers.

The first case we consider involves thousands of triggered earthquakes throughout north-central Oklahoma (the largest was M 5.8), resulting from injection of billions of m^3 saltwater into the Arbuckle Group over several years. The saltwater was coproduced with oil from conventional oil reservoirs with a high water/oil ratio. The Arbuckle is a highly permeable saline aquifer that lies at the base of the sedimentary section and immediately above crystalline basement. Induced seismicity started to escalate around 2010 as oil production increased from formations that also produced very large quantities of saltwater. While the injection into the Arbuckle is approximately 2 km deep, the earthquakes are occurring on critically stressed faults in the basement at about 6-km depth, hence the relatively large magnitudes (16). The dramatic growth in seismicity directly correlates with increased injection rates in both time and space (18). The background color on the *Left* side of Fig. 3 shows modeled pressures at the depth of the earthquakes resulting from injection into the Arbuckle (19). Note that extremely small pressure increases of 0.1 to 0.2 MPa triggered seismicity in the basement. Pressure in the Arbuckle injection zone is about 1 MPa, still a very low pressure change. Analogous earthquake-triggering in crystalline basement due to produced saltwater injection in the Ellenberger limestone which, like the Arbuckle, sits directly on basement, has been observed in the Dallas/Ft. Worth area of northeast Texas (20). The same is true in the cases of the Decatur CO_2 injection project in the Illinois Basin (21) and the

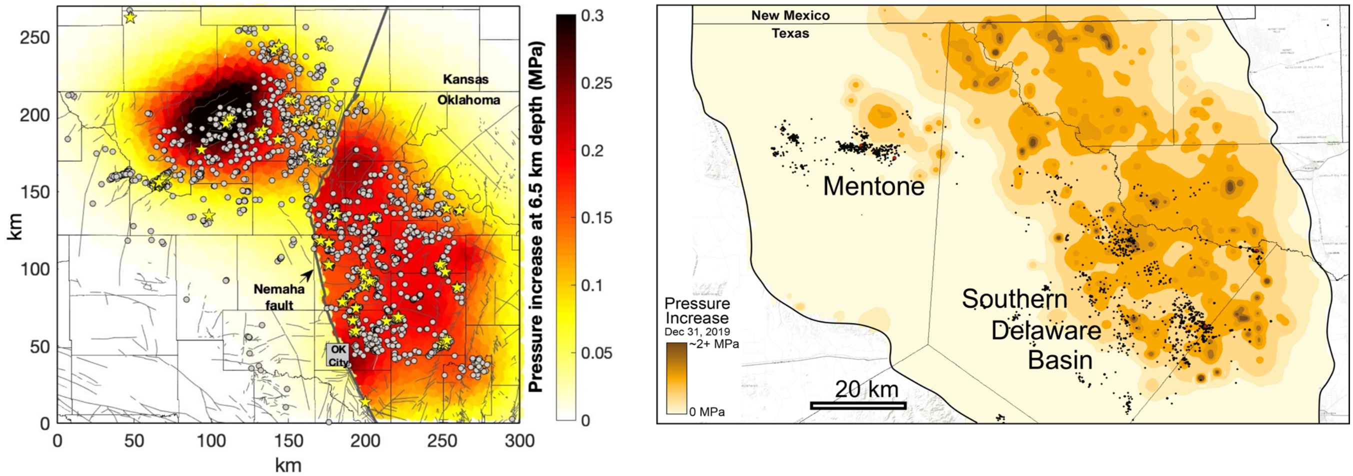

Fig. 3. (*Left*) Induced seismicity resulting from injection of saltwater into the Arbuckle group, a highly permeable basal aquifer in north-central Oklahoma. The background color represents modelled pore pressure at the depth of the earthquakes at ~6 km depth in crystalline basement (19). Circles are M>3, stars are M>4. (*Right*) Seismicity (black dots) in the Delaware Basin of west Texas and southeastern New Mexico are being induced by saltwater disposal. Injection wells are shown by green dots. The background color shows observed and modelled injection-related pore pressure changes in the Delaware Mountain Group (23). The red dots represent earthquakes larger than M 3.5 (see text).

Quest CO_2 injection project in Alberta (22). As in the Oklahoma case, pore pressure changes of less than 1 MPa in both cases triggered earthquakes on faults in underlaying crystalline basement rocks. To date, only small earthquakes have occurred in the basement beneath the injection zones at Decatur, but earthquakes as large a magnitude 3 have occurred at Quest.

Another case of injection-induced seismicity relevant to CO_2 injection in saline aquifers is the southern part of the Delaware Basin of west Texas shown on the *Right* side of Fig. 3. In this case, seismicity through 2017 (shown by black dots) results principally from from saltwater injection into a saline aquifer, the Delaware Mountain Group (DMG), at depths of approximately 2 km. In this case, saltwater injection is triggering seismicity at the same depth as injection at very small pressure changes. The background color shows injection-related increases in pore pressure in the Bell Canyon formation of the DMG that range from about 0.1 MPa to about 1 MPa in the southern part of the Delaware Basin (23). All of the earthquakes shown are relatively small (less than M 3.5), because they appear to be occurring on faults present in only the shallow sedimentary section (24). Subsequent to the time period shown, larger earthquakes (as large as M5.4) occurred in crystalline basement in the Mentone area, presumably reflecting saltwater injection into deep saline aquifers, analogous to what happened in Oklahoma. An important aspect of saltwater injection in the DMG in the southern Delaware Basin is that the injection only causes seismicity where the DMG is a saline aquifer; injection does not induce seismicity in any area where injection is into depleted oil and gas reservoirs (25). The reason for this is that past oil and gas production reduced pore pressure in the DMG more than the recent saltwater injection has increased it.

There are certainly geologic domains where CO_2 injection into saline aquifers is not likely to induce faulting such as the geologically young and poorly lithified sediments of the Gulf of Mexico. Our fundamental point is that many of the saline aquifers in continental interiors may be unsuitable for significant CO_2 storage because they are either basal units (like the Arbuckle and Ellenberger), which transmit pressure changes to critically stressed basement faults capable of producing potentially earthquakes or lithified formations (like the Delaware Mountain Group), which are prone to induced seismicity. Each saline aquifer to be considered will have to be investigated in detail to assess the potential for induced seismicity.

Conversely, the use of mature, depleted oil and gas reservoirs for CCS has several generic advantages. The reservoirs (and surrounding geologic formations) are generally well characterized, sealing formations are present (or there would not have been oil and gas accumulations), and the flow properties and seal characteristics are known from years of study. The known production and injection histories of the fields offer needed static and dynamic reservoir knowledge that makes it possible to evaluate their suitability for large-scale CCS. These attributes are not meant to suggest that every depleted oil and gas field is potentially useful for long-term geologic storage, but consideration of multiple sites in an oil and gas producing area provides the ability to assess which are suitable.

Although existing oil and gas fields already have significant infrastructure already in place, careful evaluation will be necessary to determine if wells and pipelines could be reused (or retrofitted) for CO_2 injection. The most likely depleted oil and gas reservoirs to be used for CCS were developed during the modern era (the past 30 y) when 3-D seismic data have been available to characterize the subsurface, modern geophysical well logs will have been obtained to determine formation properties, and good digital records will be available that document critical issues related to well construction. It is likely that new wells would be drilled for injection of CO_2 that would be specially designed and constructed for that process. If existing wells in a field are in poor condition, they could represent leakage pathways for CO_2 (or reservoir fluids displaced by CO_2) to shallower depths or even to the surface.

A number of theoretical studies have modeled the effects of leaking wells on the effectiveness of long-term CO_2 storage (26–29), but each field is unique depending on of the age of the wells and the details of well construction. In other words, how the wells were drilled, cased, and cemented and what information is available related to their current condition. A recent study of 130,000 well sites in the New Mexico part of the Permian Basin found that about 1.5% had detectable amount of methane leakage (30). Thus, leakage of buoyant fluids from depth needs to be considered when selecting depleted oil and gas reservoirs that will be suitable for long-term storage of CO_2. While there are parallels between assessing a depleted oil field as a potential candidate for enhanced oil recovery using CO_2 (such as the potential for a leaking well to contaminate near surface aquifers), there are important differences as CO_2 injection is cyclic when being used for enhanced oil recovery. Much of the injected CO_2 mixes with the oil is then coproduced with oil, separated and reinjected. CO_2 injection associated with CCS is cumulative, with increasing pressure over time that will need to be carefully managed.

If a leaking well is discovered during assessment of a potential depleted oil or gas reservoir suitable CO_2 storage, a number of methods have been devised to remediate wellbore leakage caused by poorly cemented casing (31). If well conditions are found to be too problematic in a potential depleted field, the field would be removed from consideration. Thus, having a portfolio of fields in an area makes it possible to select optimal candidates. This is illustrated by projects utilizing depleted gas reservoirs for CCS in the southern North Sea. Projects Porthos, Athos, and Dartagnan involve transport of CO_2 via pipelines to depleted gas reservoirs in the southern North Sea. In each case, an evaluation of existing wells was carried out to assess the condition of existing wells, and thus the suitability of the chosen field for long-term carbon storage. While these projects are examples of potentially successful CCS projects, it needs to be recognized that many CCS projects now being planned have modest goals (3). For example, the Northern Lights project in the North Sea involves transporting CO_2 by ship from multiple onshore industrial sites to a saline aquifer offshore Norway. The current plan is to start injecting about 1.4 MT CO_2/y in 2024. The Porthos project plans to start injecting 2.5 MT CO_2/y in 2024. Tens to hundreds of such projects will be needed to get to the GT/y scale noted above.

Other issues of concern arise if depletion of a candidate oil and gas reservoir has been so severe that reservoir pressures do not allow the injected CO_2 to remain in a supercritical state. In such cases, Joule Thomson cooling effects associated with rapid expansion of supercritical CO_2 need to be addressed. Similarly, reservoir compaction associated with severe depletion in relatively weak formations can significantly reduce porosity and permeability. Such changes need to be taken into account to accurately model planned rates and volumes of CO_2 injection.

CCS Economics and Value Creation

Perhaps the most important impediment restricting CCS activities around the world is that the financial incentives now in place are not sufficient for private industry to fully engage in large-scale sequestration efforts. While recently passed legislation in the United States provides incentives for both subsurface carbon storage and hydrogen production, this is not true in the rest of the world. Thus, for CCS to scale to the requisite level globally, it must create value and not be exclusively dependent on financial incentives from governments. Framed this way, it is easy to see a viable strategy to rapidly expand hydrogen production and provide opportunities for large-scale CCS from multiple sources. First, one would want to operate in an area where there is a portfolio of mature, partially depleted oil and gas reservoirs where very large volumes of CO_2 can be stored. Once a CO_2 storage facility is up and running, it can be used to store CO_2 from multiple sources. For example, a typical ATR or SMR facility will produce 1.5 to 2.0 million tons of CO_2 per year. As illustrated below, designing storage facilities in depleted reservoirs to accommodate many times that volume should be straightforward. Second, there should be local supplies of certified natural gas available for hydrogen production via ATR or SMR. Third, export of hydrogen (likely in the form of ammonia) by ship to global markets should be as easy as possible. Fourth, it could be economically attractive for the ships exporting ammonia to bring back CO_2 for disposal in the depleted oil and gas fields. This would create an economically viable carbon management strategy that addresses the growing needs for both large-scale carbon storage and hydrogen production in a safe and economically viable manner.

The strategy we propose is particularly applicable in oil and gas exporting countries where numerous depleted reservoirs exist that may be suitable for CCS (32). In particular, the numerous partially depleted oil and gas fields in the Middle East seem like an ideal opportunity for large scale-up in relatively short periods of time because of the low population density. As a representative example, we consider the depleted oil and gas fields of Oman, a major oil and gas exporting country where publicly available data allow us to illustrate the general strategy we propose. Over the past ~50 y, about 13 billion barrels of oil and 230 trillion m^3 of natural gas (at standard conditions) has been produced (33) (*Left* side of Fig. 4) from about 150 onshore fields (some of which are shown in on the *Right* side of Fig. 4). This amount of fluid represents a fluid volume of about 1 trillion m^3 under reservoir conditions. One GT of CO_2 occupies a pore volume of about 1.3 billion m^3. Hence, the theoretical capacity for CO_2 in these depleted fields is enormous, and one would have many fields to choose from for initial activities. Appreciable infrastructure is already in place (about 10,000 km of pipelines, for example), as well as numerous facilities that could be repurposed for CO_2 injection and transport of hydrogen (likely in the form of ammonia). The pipelines are connected to a deep-water port in Muscat, which enables Omani oil and gas to be exported (black diamond on the *Right* side of Fig. 4).

In one hypothetical scenario, an SMR or ATR plant in Oman would use locally sourced, certified methane to produce hydrogen and would be located relatively near a mature, depleted fields that would be suitable for CO_2 storage. CO_2 from other point sources in the region could also be stored in the same fields. Having a portfolio of possible fields for CCS, optimal fields would be utilized first, but

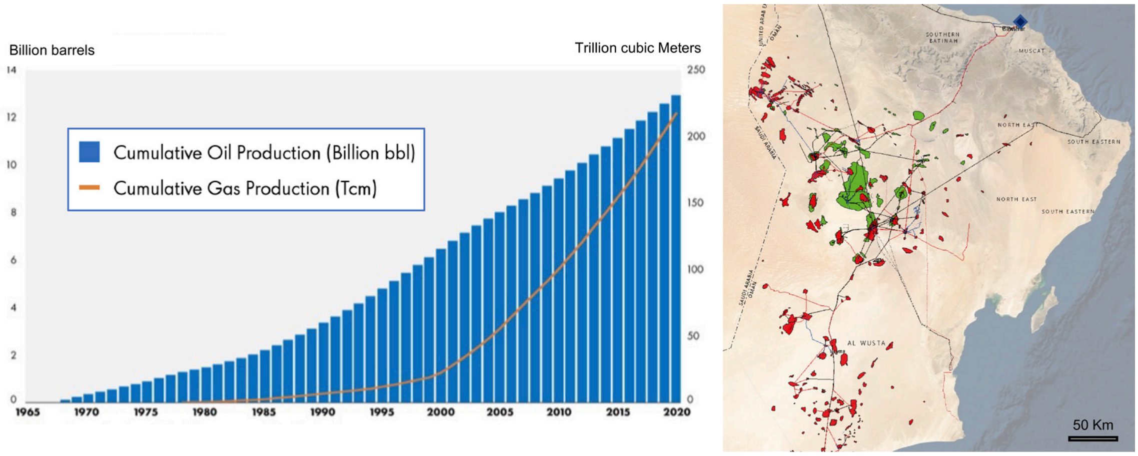

Fig. 4. (*Left*) Cumulative oil and gas production in Oman (26). (*Right*) Map of some of the mature oil (red) and gas (green) fields and pipeline infrastructure in Oman. The sea port in Muscat is indicated by the red star.

there could be considerable growth in CCS and hydrogen production by utilizing more sites over time. This would allow for a staged approach to investments and a distributed hazard and risk approach, which is inherently more efficient. Furthermore, as the blue hydrogen/ammonia is conveniently located for export by tanker ships to global markets, CO_2 from heavy industries could be transported back to Oman especially from countries in Asia with densely populated urban regions where opportunities for CCS may not be available.

A critically important attribute of the mature oil and gas fields in countries like Oman is that appreciable geologic and hydrologic characterization and production modeling has already been done. Indeed, many fields in Oman (and other oil producing countries) have been developed with secondary and tertiary production technologies that have required significant analysis of injection processes. Thus, over several decades a significant body of knowledge has been obtained on injection opportunities and their hazard and risks. This will enable modeling of CO_2 injection to proceed immediately with well-constrained reservoir parameters. There can be hundreds of wells in some these fields, some of which might be repurposed for CO_2 injection or converted to wells to be used for comprehensive monitoring. Obviously, potentially problematic wells need to be appropriately repaired or plugged to prevent leakage.

The economic viability of such hypothetical scenarios depends on many unknowns, which is not the intent of this paper. However, it becomes clear that an economically viable system approach is needed to enable rapid expansion of both CCS and hydrogen production. Such expansion could occur anywhere there is a portfolio of partially depleted fields suitable for CCS, certified natural gas, and convenient opportunities of export. Oman is an excellent example, but many such places exist around the world.

Conclusion

As society tries to deal with the threats of climate change, every action contributing to reduced greenhouse gas emissions is a good one. The intent of this paper is not to make a case for blue vs. green hydrogen, nor CO_2 storage in depleted oil and gas reservoirs vs. saline aquifers. Rather, the intent of our paper is to take a hard look at options for accelerating large-scale decarbonization efforts over the next decade. Thus, the issues we address here are how to rapidly scale up the volume of anthropogenic CO_2 being stored in the subsurface and how to simultaneously kick-start global production of hydrogen to be used as a key component of clean energy scenarios. With sufficient time and effort, saline aquifers in continental interiors will be found that can safely store significant quantities of CO_2. It is also possible that with sufficient government incentives, stand-alone CCS might be a viable business for companies to engage in. The recently approved tax incentives for carbon storage in the United States are one such example, but such incentives are unlikely in oil and gas exporting countries where numerous depleted oil and gas reservoirs exist that may be suitable for long-term CO_2 storage. Decarbonization is a global challenge and greatly accelerating CCS during the next decade is critical. Considering the limited knowledge of the great majority of saline aquifers around the world, the use of depleted oil and gas reservoirs for CO_2 storage in vertically integrated, value-creating systems seem necessary to meet the goals of scale, safety, and economic viability that will make large-scale CCS and hydrogen production critical components of global decarbonization efforts.

Data, Materials, and Software Availability. Previously published data were used for this work (19, 23, 25). All of the data used in this paper are in the public domain, in the citations referenced.

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