Strategic Carbon Dioxide Infrastructure to Achieve a Low-carbon Power Sector in the Midwestern and South-central United States

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Synopsis
We provide quantitative policy targets to incentivize large-scale CCUS infrastructure in the U.S. to decarbonize the power sector.

Abstract

Large-scale carbon capture, utilization, and storage (CCUS) requires development of critical infrastructure to connect capture locations to geological storage sites. Here, we investigate what government policies would be required to make the development of CO_2 pipelines and large-scale CCUS in the power sector economically viable. We focus on the transition from conventional coal to non-CO_2-emitting natural gas-fired Allam-cycle power with CCUS and study a system in which 156 Allam-cycle power generators representing 100 GW of capacity send their captured CO_2 emissions to three geological storage locations in the central United States through 7,500 miles of new pipeline. Enabling policies for this system include low-interest government loans of approximately \$20 billion for pipeline construction and an extended 20-year Section 45Q tax credit, or similar longer-term carbon price incentive. Additional policy support will be needed to enable initial construction of pipelines and early-mover power generators, such as cost-sharing, governments assuming future demand risk, or increased subsidies to early movers. The proposed system will provide reliable, dispatchable, flexible zero-emission power generation, complementing the intermittent generation by renewables in a decarbonized U.S. power sector. The proposed pipeline network could also connect into future regional infrastructure networks and facilitate large-scale carbon management.

1. Introduction

Large reductions in anthropogenic carbon dioxide (CO_2) emissions are required to avoid catastrophic impacts of climate change. Carbon capture, utilization, and storage (CCUS) is a technology where CO_2 is captured from stationary sources such as fossil-fuel power plants, or directly from the air, and is subsequently reused or injected into suitable deep geological formations for long-term and secure storage. Studies have shown that CCUS is necessary to meet the 2°C climate goal of Paris Agreement and that CCUS lowers the system-wide cost of decarbonizing energy and industrial sectors.[1-4] Recent modeling studies consistently cite CCUS as a key component for the United States to achieve economy-wide net-zero carbon emissions by 2050.[5,6]

Large-scale CCUS deployment has been held back largely by economic challenges,[7,8] due especially to the high cost of carbon capture. A large-scale CCUS industry also requires infrastructure in the form of pipelines to connect CO_2 sources to suitable subsurface storage locations. While CO_2 pipelines currently exist around some enhanced oil recovery (EOR) operations, the pipeline network is not at sufficiently large scale for development of an effective large-scale CCUS industry.

In the United States, the reform and expansion of the Section 45Q tax credit in 2018 provides up to \$50 for secure storage of one metric ton (tonne) of captured CO_2 in deep saline aquifers and up to \$35 for secure storage of one tonne of captured CO_2 in oil reservoirs through EOR. This provides significant financial incentives for CCUS deployment. A recent technological development may also allow lower-cost CO_2 capture from power plants. The Allam power cycle is a new oxy-fuel combustion cycle that uses supercritical CO_2 as the working fluid. An Allam-cycle power plant would burn natural gas for power generation and capture nearly 100% of its pure CO_2 waste stream at an electricity cost comparable to conventional power plants that do not capture CO_2, according to its developers.[9,10] Recent analyses of the economics of achieving near-zero emissions in the electricity system consistently show that dispatchable, flexible zero-emission electricity generation will be a critical complement to intermittent generation by renewables to enable the lowest-cost, most-reliable, zero-carbon system.[11-13] Allam-cycle power plants are an attractive candidate for this role. A literature review of Allam power cycle is provided in the Supporting Information (SI).

In this work, we analyze the potential for large-scale deployment of CO_2 transport infrastructure and power-sector carbon capture projects in the Midwestern and South-central United States over the next few decades and examine how government policies and technological development may affect the economic feasibility and dynamics of the system. We focus on the transition from coal to non-CO_2-emitting power based on the Allam cycle with CCUS, and investigate what policies would enable an evolving CO_2 pipeline network that connects 156 Allam-cycle power generators to three geological basins which have large CO_2 storage capacity. Such a large-scale system would capture and store substantially more CO_2, at a lower unit price, than individually-developed local small-scale projects due to the inherent economies of scale. We consider low-interest government loans for pipeline construction and an extended Section 45Q tax credit or similar longer-term carbon price incentive to improve the economics for investors of Allam-cycle power plants. These policies are consistent with the Biden Administration's and U.S. legislators' approach to support CCUS and U.S. National Academies' advice that highlight the importance of CCUS.[14-18] They also would align the United States with a number of developed countries whose governments recently committed substantial investment to CO_2 infrastructure in pursuit of their national net-zero goals.[19-24]

This work expands on previous work that has proposed and analyzed aspects of CO_2 pipeline development in the United States. Models such as *SimCCS* have been developed to plan for CO_2 pipeline routes.[25,26] Abramson et al. (2020) planned CO_2 pipeline networks for industrial and power facilities with carbon-capture-retrofit potential in the Central United States and concluded that CO_2 pipelines built with large capacity for long-term planning horizons would involve much lower per-tonne transport costs, benefiting from the strong economies of scale of pipeline materials and construction.[27] Edwards and Celia (2018) analyzed the viability of a CO_2 pipeline network to transport CO_2 from existing ethanol bio-refineries in the Midwest to Texas for EOR;[28] that work took advantage of the low capture costs associated with ethanol production. Our work uses a similar method of pipeline route planning and applies similar calculations for financial viability as that used by Edwards and Celia (2018), but now the application is to the electric power sector, which involves an order of magnitude more CO_2 emissions than the ethanol industry and requires more expensive carbon capture because gas separation is required to capture CO_2 generated from a conventional power plant. We also consider both saline aquifer storage and storage via EOR. Going beyond Edwards and Celia (2018)'s approach, we also incorporate a time dimension into the analysis and investigate the dynamics of pipeline construction and subsurface utilization from now to the 2070s.

2. Study Region and System Description

Our study region includes the Ohio Valley and lower Mississippi Valley with extension from the Mississippi River west into Oklahoma and West Texas. It has the largest, oldest, and densest coal fleet in the United States, with many plants located along the Ohio River (see Figure 1A). This region is not projected to have early or major deployment of wind and solar renewable power in the United States due to its relatively modest wind speed and solar irradiance.[5,29,30] It, however, contains a number of geological basins with the largest subsurface CO_2 storage capacity in the country (see Figure 1B). EOR is an existing industry that has stored CO_2 for over 40 years but has limited storage capacity; saline-aquifer storage is less commercially mature but has vast potential storage capacity.

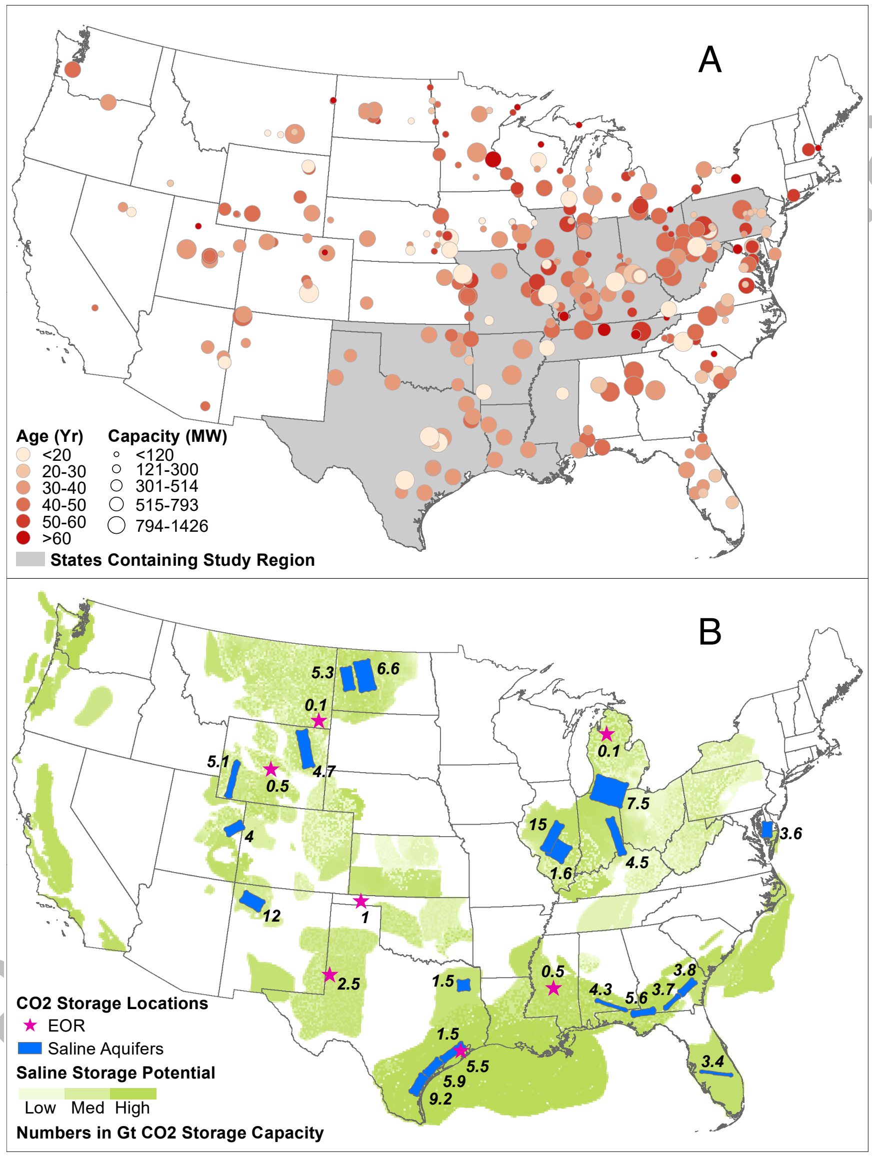

Figure 1. (A) Locations of operating coal-fired power generators in the contiguous United States. As of December 2019 there were 660 coal-fired generators with a total nameplate capacity of 248 GW.[31] (B) Subsurface CO_2 storage capacity in the contiguous United States. Blue rectangles indicate both location and areal extent of the saline storage reservoirs.[32] Their storage capacity corresponds to 50 years of sustainable CO_2 injection.[32] As shown in that

reference, the storage capacity increases for longer time horizons. Pink stars give the approximate locations of EOR storage based on current CO_2-EOR activities.[33] Their storage capacity was estimated based on CO_2-EOR potential in the region.[34-40] Green indicates general saline storage potential.[41]

We seek to determine the additional cost associated with replacement of retiring coal-fired generators with Allam-cycle gas generators utilizing CCUS. Because Allam-cycle generators provide firm dispatchable power, the additional cost is calculated relative to the replacement costs of a conventional natural gas-fired combined-cycle (NGCC) generator without carbon capture, which is currently the predominant technology for new-build firm dispatchable power. This baseline replacement is reasonable given that 60% of retired U.S. coal capacity in the past ten years switched to burning natural gas, without carbon capture, at their original locations – half was replaced by new NGCC generators and the other half had the boiler converted to burn natural gas.[42] Such transition from coal to gas is already taking place in our study region and is likely to continue because of the existing power infrastructure and natural gas pipelines and because the region has limited potential for wind and solar power. Moreover, use of NGCC to replace coal is likely to grow in the coming years because NGCC capacity has significantly outgrown other types of natural gas-fired generating technologies (i.e., natural gas-fired combustion and steam turbines) in the U.S. over the past decade.[43] NGCC also runs more frequently than the less-efficient gas combustion and steam turbines, which are typically only used during peak hours. In 2018, NGCC provided almost 90% of total natural gas-fired generation in the U.S.[43]

We recognize that this baseline replacement may not be appropriate late in our study period. For example, if new carbon-emitting generators are banned in the coming decades, the baseline replacement of coal capacity should be NGCC generators equipped with carbon capture; also, future advances in other technologies such as advanced nuclear power or long-duration energy storage could mean other technologies besides natural gas power are the baseline for firm dispatchable power. However, given the current technologies and policy environment, for this work we assume baseline replacement of coal by NGCC without carbon capture.

Our calculations involve all aspects of the CCUS system including construction and operational costs for Allam-cycle generators as well as the costs associated with pipeline construction to transport the captured CO_2 to the appropriate geological storage sites (or "sinks"). The costs of Allam-cycle generators are modeled to decrease with cumulative installed capacity due to learning-by-doing. We also consider the costs of CO_2 storage in the deep saline aquifers and revenues from selling CO_2 to EOR operations. We assume equity investors of Allam-cycle power plants can fully monetize the Section 45Q tax credit and therefore receive revenues from this tax credit. We assume the start-of-construction deadline for the Section 45Q tax credit will be extended indefinitely after the current deadline of January 1, 2026. Extension and removal of this deadline have been proposed in Congress.[44-46] Finally, we assume the cost of baseline replacement by NGCC plants without carbon capture could be justified by electricity sales alone, so electricity price is not considered when determining the economics of the additional cost.

The CO_2 sources for the pipeline network are assumed to be Allam-cycle generators that are built at the same location as the current coal-fired generators following their retirement, with the same generating capacity. This avoids extra siting and permitting requirements for construction at new locations and utilizes existing plant spaces, power plant workforce, water sources, and power transmission lines. Because the retirement dates of coal-fired generators vary, the replacement Allam-cycle generators will come online gradually. To streamline the analysis, we grouped new Allam-cycle generators by decade. For example, expected Allam-cycle generators from 2020 to 2030 are assumed to come online in 2030. Similarly, additional groups of Allam-cycle generators will come online in 2040, 2050, and 2060. This is a reasonable assumption, given the current early development stage of Allam-cycle generators and the fact that it takes a few years to prepare a decommissioned coal-fired power plant site for a new power station, and the actual retirement year for a given coal plant is somewhat uncertain. 156 Allam-cycle generators form the basis of this analysis. They all have large capacity to qualify for the Section 45Q tax credit and are on average only 6.7 km away from existing natural gas pipelines, demonstrating potential for convenient fuel supply. These 156 generators are divided into a Northern group, replacing coal generators along the Ohio Valley, and a Southern group, which are more scattered in the South Central states (see Table 1 and Figure 2).

Table 1. Information of Allam-cycle generators in the Northern and Southern groups. Data sources, assumptions, and justifications are provided in Section 3.1 and the SI.

	Northern group			Southern group		
Online year	Number of generators	Total capacity (GW)	Projected CO_2 captured (million tonnes per year)	Number of generators	Total capacity (GW)	Projected CO_2 captured (million tonnes per year)
2030	81	51.3	111.3	14	8.9	19.2
2040	12	8.4	18.3	29	18.3	39.7
2050	2	2.0	4.3	2	0.9	2.0
2060	10	5.5	11.8	6	5.0	10.9
Total	105	67.2		51	33.1	

The designed pipeline network will transport CO_2 from Allam-cycle generators along the route to three storage basins for long-term secure storage. Those include the Illinois Basin, the Permian Basin in West Texas, and the Frio Formation along the Gulf Coast, all of which have intensive geological characterization and existing CO_2 injection activities.[33,47] With foresight in the design of the system, the main trunk of the pipeline network needs to be oversized initially to allow for additional future CO_2 sources to connect into the main trunk as coal-fired generators gradually retire and new Allam-cycle generators come online (or, alternatively, new pipelines could be built, but that would be more time-consuming and costly due to the economy-of-scale of pipelines[27,28]). The first group of Allam-cycle generators will have to bear higher transport costs to use the oversized main trunk pipeline, unless policy mechanisms are used to alleviate or spread these costs. The unit cost of main trunk pipeline transport will decrease as more Allam-cycle generators are connected to the main trunk. Individual generators will also pay a tariff for feeder pipelines which will connect them to the main trunk pipeline.

Like the Allam-cycle generators, the pipeline is divided into a Northern network and a Southern network in this analysis. The Northern network can deliver CO_2 from Northern generators to any of the three geological basins, while the Southern network delivers CO_2 from Southern generators to the Permian Basin or the Gulf Coast, but not northward to the Illinois Basin. Figure 2 shows the designed pipeline network for a specific arrangement in which the Northern generators use the Gulf Coast and the Illinois Basin for CO_2 storage and the Southern generators use the Permian Basin. Other arrangements would lead to different designs of the pipeline network; all possible combinations were analyzed in this work, including the arrangements in which the Northern generators only use the Illinois Basin, thereby eliminating the long Northern pipeline section south of Illinois (see the SI for details). At full development, the pipeline network shown in Figure 2 consists of 2614 miles of main trunk and 4953 miles of feeder pipelines. This would more than double the existing 4500 miles of CO_2 pipelines in the United States that transport 68 million metric tons (Mt) of CO_2 for EOR each year.[48] For context, there are more than 300,000 miles of natural gas transmission pipelines in the United States.[49]

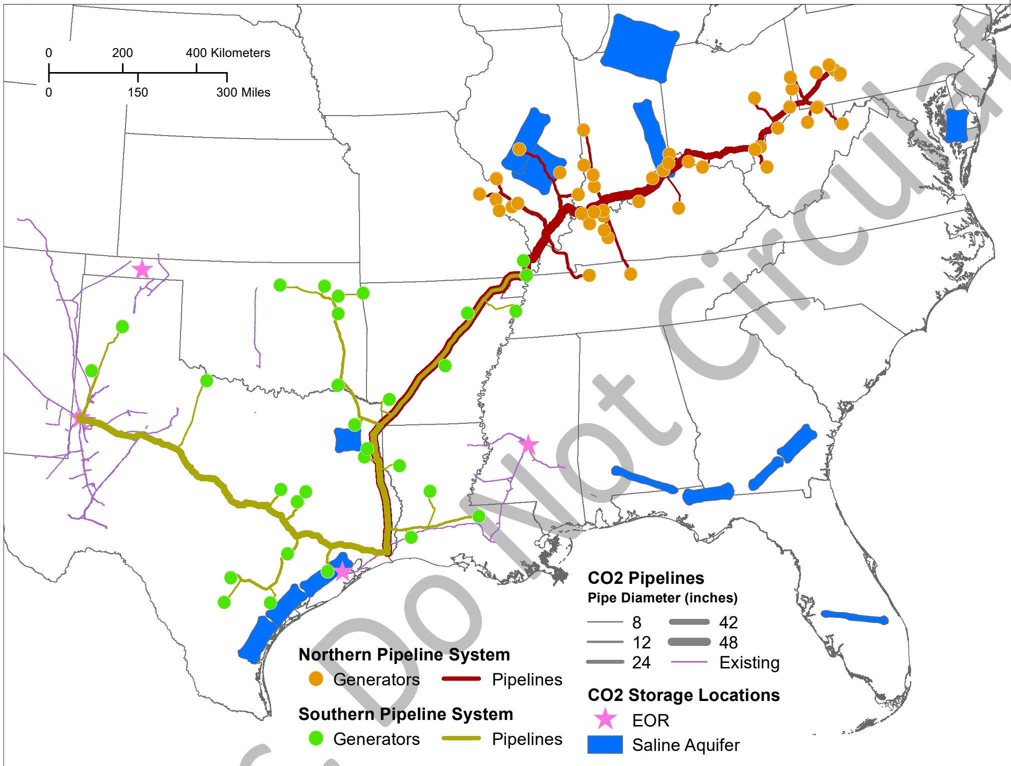

Figure 2. Illustration of the pipeline system in the base case. The Northern pipeline system consists of Allam-cycle generators in the Northern group (in orange) and Northern pipeline network (in red). The Southern pipeline system consists of Allam-cycle generators in the Southern group (in green) and Southern pipeline network (in olive). The methodology of determining this pipeline system is explained in Section 3. The pipeline for the Northern and Southern systems overlap from Illinois to the Gulf Coast. This overlap is necessary because the Northern main trunk south of Illinois has reached full transport capacity constrained by maximum pipe diameter and reasonable spacing of pump stations, and is unable to pick up captured CO_2 from Southern generators. The purple lines are existing CO_2 pipelines. Blue rectangles and pink stars indicate CO_2 storage locations associated with saline storage and CO_2-EOR, respectively.

3. Materials and Methods

3.1 Sources of Captured CO_2 Emissions

We assumed an Allam-cycle generator captures 100% of CO_2 emissions, operates at a capacity factor of 55%, which is the same as the current capacity factor of utility-scale NGCC generators in the United States,[50] and produces 450 kg CO_2 per MWh of power generation.[51,52] This means Allam-cycle power generators whose nameplate capacity are larger than 231 MW would capture more than 0.5 Mt of CO_2 emissions annually and therefore qualify for the Section 45Q tax credit. There were 156 operating coal-fired generators in our study region with capacity larger than 231 MW as of December 2019, according to Form EIA-860M based on monthly survey of U.S. electric generator inventory.[31] The Allam-cycle generators replacing those 156 coal-fired power generators after their retirement form the basis of this analysis. More details are in the SI.

3.2 Pipeline Network Design

Following Edwards and Celia (2018),[28] we assumed new CO_2 pipelines would be constructed in existing rights-of-way, which are current infrastructure networks in the United States including railways, interstate highways, high-voltage power transmission lines, and natural gas, ammonia, and CO_2 pipelines. We selected the main trunk pipeline route based on the shortest routes from the 156 Allam-cycle power generators to the three CO_2 storage basins, weighted by each generator's CO_2 capture capacity. Once the main trunk was specified, we determined the routes for feeder pipelines by first finding the shortest routes from individual generators to the main trunk and then manually editing the routes to allow feeder pipelines of the same online year to aggregate early for pipeline economy-of-scale. Operations were conducted in ArcGIS. More details of the pipeline design are in the SI.

3.3 Transport Tariff for Pipeline Users

Pipeline tariff is the charge to Allam-cycle power plants for use of the pipeline network, in units of dollars per tonne of CO_2 transported. In this work, pipeline tariff equals to pipeline's operating cost plus an amount needed to recover the capital investment of the pipeline investors plus a target rate of return. After the pipeline's capital cost is fully recovered, the tariff is set equal to the pipeline's operating cost plus a 10% margin. The pipeline's capital and operating costs were minimized using the U.S. Department of Energy NETL CO_2 Transport Cost Model.[53] An Allam-cycle power plant's pipeline tariff is based on the portion of pipeline network that it uses, and would change whenever there is a change to CO_2 flow in the main trunk pipeline caused by other Allam-cycle power plants. More details of the tariff calculation and the CO_2 transport cost model are included in the SI.

3.4 Cost Estimates for Allam-cycle Generators

Because the Allam cycle represents a new technology, we modeled its capital cost reductions between first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) generators using a conventional log-linear learning curve, with a FOAK capital cost of \$1850/kW, a learning rate of 10%, a learning onset point of 10 GW, and a learning end point of 100 GW. We also assumed the same amount of Allam-cycle deployment outside of our system, over the same time period, resulting in an expedited learning in our system. Descriptions, justifications, and references of these (and other) parameters are provided in the SI. A sensitivity analysis is provided in Section 4.1 and the SI. This learning curve resulted in an NOAK capital cost of \$1304/kW for Allam-cycle generators, consistent with information in the literature.[54-56] For context, NGCC with and without carbon capture currently have capital costs of around \$2800/kW and \$1000/kW, respectively.[57,58] After determining the learning curve, we ranked all Allam-cycle generators in our system based on expected online date and then assigned capital costs based on cumulative installed capacity and the associated learning that had taken place by that time.

3.5 Economic Viability of the Pipeline System

We created a financial model from the perspective of Allam-cycle power-plant investors. The model was applied for each Allam-cycle generator sequentially in chronological order, with generator-specific input parameters such as online year, annual CO_2 captured, additional capital and operational costs relative to a conventional NGCC generator without carbon capture, and pipeline tariff throughout its financial lifetime. The financial model then calculated free cash flow for each generator considering all costs and benefits (as shown in Figure 3), and eventually summed the present value of free cash flow for all generators in the system to determine the system-wide net present value (NPV). A positive system-wide NPV means it would be economically viable (collectively) to build such system. In the financial model, escalation rate and inflation rate were both set to 2%. We used a flat CO_2 saline storage cost of \$12.5/tonne in the Illinois Basin and \$9.5/tonne in the Gulf Coast.[59] We also used a CO_2 sales price of \$23/tonne to EOR operations, corresponding to a crude oil price of around \$60/barrel. Other financial parameter assumptions and the financial model are included in the SI.

4. Results and Discussion

4.1 The Base Case

We design a number of spatiotemporal arrangements to match Allam-cycle generators with CO_2 storage basins through the pipeline network during the study period (2030-2071). In the spatial dimension, the CO_2 sinks are chosen from: 1) saline storage in the Illinois Basin; 2) saline storage in the Gulf Coast; 3) EOR storage in the Gulf Coast, and 4) EOR storage in the Permian Basin. In the temporal dimension, the time period that CO_2 is directed to a certain CO_2 sink depends on how many generators are using the pipeline network and how large the remaining storage capacity is at that storage site. In our analysis, the Allam-cycle generators continue operating for the duration that there are financial incentives for CO_2 capture.

We analyzed 10 arrangements, representing all permutations for our study region and system, to determine the most economically favorable one, which we use as the base case. The analysis is provided in the SI. The base case involves the Northern group of generators initially sending their captured CO_2 to the Gulf Coast for EOR, starting in 2030 and ending in 2041 when the Gulf Coast storage capacity is exhausted. After that, the Northern generators send their CO_2 to the Illinois Basin for saline storage, through the end of the analysis period, which is 2071. The Southern group of generators send their CO_2 to the Permian Basin for EOR for the entire period, 2030-2071. A detailed description of the base case is included in the SI. While the base case is most financially favorable, it is still not profitable because NPV of the Northern and Southern systems sums up to -\$4.29 billion, a negative value. NPV of individual generators is plotted in Figure 3. In the rest of this paper, we analyze the base case and explore policy options that could make the overall NPV positive, both collectively and for all individual generators.

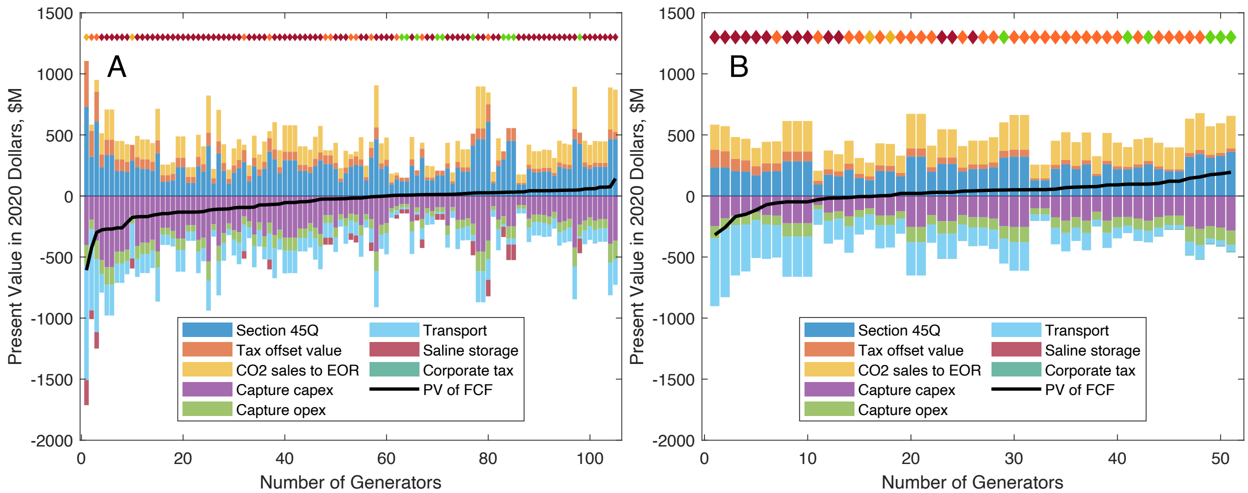

Figure 3. Present value (PV) of the costs and benefits for individual Allam-cycle generators in (A) the Northern system and (B) the Southern system in the base case. Free cash flow (FCF) is the net of total benefit (positive readings) and total cost (negative readings). Tax offset value is resulted from our assumption that equity investors of Allam-cycle power plants can use depreciation and operating losses to offset tax on other income. Red, orange, yellow, and green diamonds indicate generator online years of 2030, 2040, 2050, and 2060, respectively. Width of the bars and size of the diamonds have no meanings. A figure of the same type showing levelized cost and benefit for individual generators is included in the SI.

In the base case, both the CO_2 pipelines and Allam-cycle power plants require a commercial rate of return (ROR) on invested equity. For the pipeline investor, that means financing the pipeline construction with 50% equity and 50% debt with an equity ROR of 12% and a debt interest rate of 6%. These rates were chosen so that the weighted average cost of capital was 8.3%, a typical rate for major oil and gas pipeline companies.[60] For the power-plant investor, we assume 100% equity financing because of the need for tax equity to monetize the Section 45Q tax credit. The ROR is set to 15% in the base case. This is set higher than the average authorized equity ROR for electric utilities in the United States, which is around 10%,[61] to account for the risk premium associated with new Allam-cycle technology.

Figures 4A-4C show the aggregate free cash flow of the pipeline networks in nominal dollars. The Northern pipeline requires larger investment during construction period (2026-2029) and receives larger tariff revenue from 2030 to 2041 as compared to the Southern pipeline because the long main trunk section that connects the Illinois Basin and the Gulf Coast is no longer used by the Northern generators after 2041. The capital cost of the Northern and Southern pipeline network is estimated to be \$11.4 billion and \$8.6 billion in 2020 dollars, respectively.

Figure 4C shows that the pipeline investors will need to make an equity investment of \$10 billion to build the pipeline network from 2026 to 2029 and will have positive free cash flow in each year from 2030 to 2071. Given that 3960 Mt of CO_2 are stored during the study period, the net equity investment to transport 1 tonne of CO_2 through pipeline is \$2.6 in nominal dollars. From Figure 4F, the power-plant investors will need to make an equity investment of \$31 billion during 2028-2029, a net investment of \$2.9 billion during 2038-2039, \$1.9 billion during 2052-2057, and \$7.5 billion during 2058-2059, and will have positive free cash flow in all other years until 2071. We remind the reader that the power-plant investors' investment refers to the additional cost associated with replacing retiring coal-fired generators with Allam-cycle generators with CCUS relative to the assumed replacement by conventional NGCC generators without carbon capture. The net equity investment to capture and transport 1 tonne of CO_2 through this pipeline system is \$13.6 in nominal dollars. Note that a "pipeline system" was defined to include both Allam-cycle generators and pipeline networks.

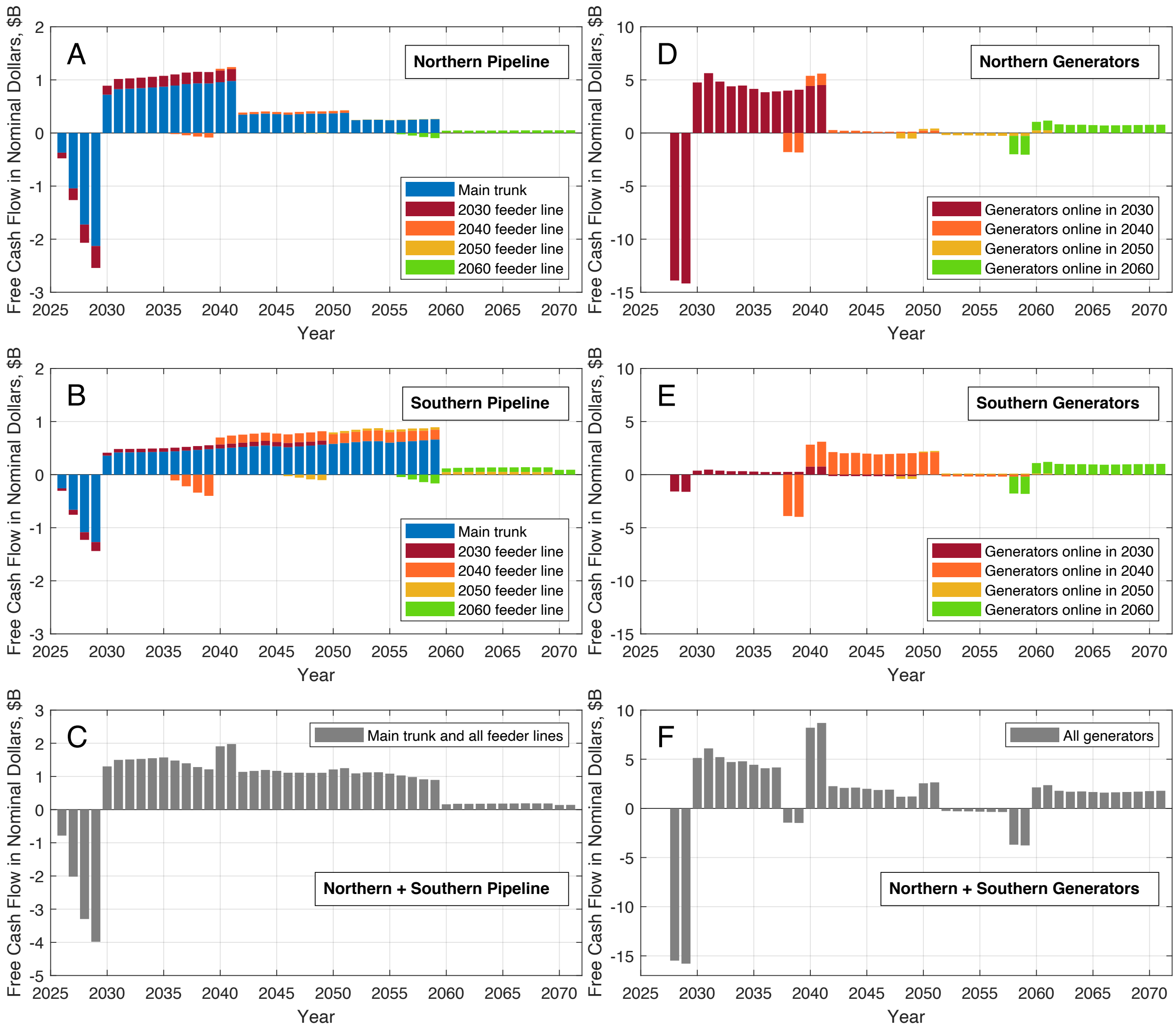

Figure 4. Aggregate free cash flow for equity investors of (A) Northern pipeline network, (B) Southern pipeline network, and (C) entire pipeline network, and equity investors of (D) Northern power plants, (E) Southern power plants, and (F) Northern and Southern power plants during the assets' construction period and financial lifetime in the base case. Aggregate free cash flow is the summation of free cash flow through all members of a color-coded group. Free cash flow is in nominal dollars.

We conducted a sensitivity analysis to assess how changes in the input parameters to the power-plant investor's financial model would affect system-wide NPV for the base case. The parameters we investigated are learning curve for Allam-cycle generators (shown in Figure 5A), geographic locations of new Allam-cycle generators, oil-linked CO_2 sales price to EOR operations, fuel price to Allam-cycle generators, and saline storage cost.

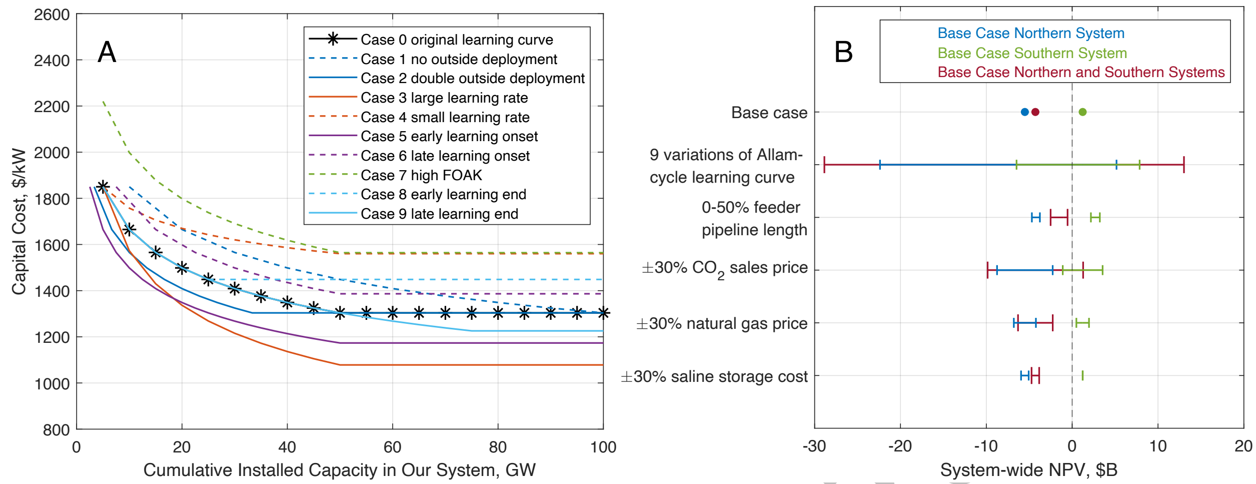

Figure 5. (A) Shapes of Allam-cycle generator's learning curve investigated in the sensitivity analysis. The learning curve used in the base case is referred to as the "original learning curve" here. We investigated 9 variations of the learning curve, changing one component of the curve at a time (components are listed in Section 3.4). The capital cost readings at 100 GW are close to estimates of NOAK capital cost reported in the literature.[54-56] This indicates our sensitivity model covers the likely range of the learning curve. Learning curve specifications, justifications, and references are in the SI. (B) System-wide NPV calculated using different values of input parameters to the financial model in the base case. ±30% CO_2 sales price to EOR operations corresponds to a crude oil price of $42-78/barrel. ±30% natural gas price corresponds to $3.3-6.1/MMBtu. ±30% saline storage cost corresponds to $8.8-16.3/tonne CO_2. Values are in 2020 dollars.

Figure 5B shows that Allam-cycle generator's learning curve has the most significant impact on system-wide NPV. This is because capital cost of Allam-cycle generators is a substantial part of total cost for power-plant investors, as shown in Figure 3. The possible relocation of Allam-cycle generators towards the main trunk pipeline, hence reducing the length of less-cost-effective feeder pipelines, would modestly improve the NPV. However, this would involve extra burdens associated with the siting and permitting process and new power infrastructure construction, not to mention issues of public acceptance of a new location for the power plants. This supports our assumption to locate the new Allam-cycle generators at the location of the retiring coal-fired plants. Fluctuating crude oil and natural gas prices would affect system-wide NPV through oil-linked CO_2 sales price to EOR operations and fuel cost of Allam-cycle generators, respectively. Variation of saline storage cost has a small impact on the NPV because generators mainly use EOR for CO_2 storage in the base case. An extensive sensitivity analysis is provided in the SI.

4.2 Additional Scenarios: Two Policy Actions on Top of Base Case

In Section 4.1, we examined the base case and conducted a sensitivity analysis on factors that cannot be controlled directly. Here, we explore two policy actions to improve the economic feasibility of the base case. The first policy, which we call Scenario 1, involves pipeline construction financing. Rather than requiring a commercial market ROR, we consider an option where the pipeline construction is financed entirely by low-interest government debt, thereby reducing the cost of construction to the pipeline investor and the tariff for using the pipeline network. This will improve the NPV of the pipeline system. We use a rate of 3.5%, which is the maximum 20-year treasury bond rate over the past 5 years, to represent the expected rate over the study period. If the average rate is in fact lower than this, the NPV will improve further.

With Scenario 1, the overall NPV changes from negative to positive (see Table 2) making the overall system economically viable, although the Northern system still has a negative NPV. The Northern system always has a lower NPV than the Southern system. This is because the coal fleet in the northern part of our study region is older so the Northern replacement Allam-cycle generators must come online earlier, which means they are early in the technology learning curve (see Figure 5A) and will thus have higher capital costs.

The second policy intervention (Scenario 2) builds on Scenario 1 and, in addition to providing low-interest (3.5%) government debt on pipeline construction, involves a lengthening of the 12-year Section 45Q tax credit to a 20-year tax credit. With this lengthening, Allam-cycle generators in the pipeline system can have longer, 20-year pay-back periods, which improves their economics. We note that the longer duration of Section 45Q tax credits also implies larger costs for the federal government through reduced tax revenue (~$5 billion/year), around half of the current federal tax-related support for renewable energy.[62] Relevant analysis is in the SI.

Table 2. Specification and NPV results of the three financing scenarios considered in this paper. NPV is in 2020 dollars.

	Pipeline financing			Power-plant financing		Section 45Q tax credit length (year)	Study period	Total CO_2 stored (EOR : Saline) (Mt)	Total NPV ($B)	Northern system NPV ($B)	Southern system NPV ($B)
	Equity debt ratio	Equity ROR	Debt interest rate	Equity debt ratio	Equity ROR						
Base case	50% / 50%	12%	6%	100% / 0%	15%	12	2030 - 2071	3960 (9:1)	-4.29	-5.51	1.23
Scenario 1	0% / 100%	-	3.5%	100% / 0%	15%	12	2030 - 2071	3960 (9:1)	1.97	-2.15	4.12
Scenario 2	0% / 100%	-	3.5%	100% / 0%	15%	20	2030 - 2079	5546 (7:3)	9.35	2.83	6.52

In Scenario 2, although both Northern and Southern systems have positive system-wide NPV, 31 of the 105 Northern generators and 2 of the 51 Southern generators still have negative individual NPV. Those are generators that either come online early or are far from CO_2 storage basins and therefore have higher generator and CO_2 transport costs. Without additional policy incentives, those generators will not participate in the system because they are not earning the required ROR. If the individual generators with negative NPV are removed from the system, the remaining generators will need to pay a proportionally higher pipeline tariff and will move toward the earlier (more expensive) part of the technology learning curve. Those higher costs eliminate additional generators, leading to a negative feedback where fewer generators will choose to participate in this system. The results of this kind of iterative calculation for Scenario 2 is that the system continues to shrink until no generators remain (see SI for details and illustrations of each of the iterations). This is the outcome we want to avoid and we therefore consider additional policy approaches that will create the pipeline system while allowing each individual power-plant investor to make their own decisions based on profitability.

Four types of policy measures, when applied on top of Scenario 2, would be able to ensure all generators have positive individual NPV leading to their participation. The first is to implement a system-wide cost-sharing scheme, in which generators with positive NPV will pay a proportionally higher pipeline tariff so that generators with negative NPV can pay a lower tariff leading to them having a positive NPV and participating in the system. In this cost-sharing scheme, as long as the system-wide NPV is positive (as in both Scenario 1 and Scenario 2), it is possible to make every generator have a positive individual NPV. This strategy could be achieved through government regulation, as occurs in other similar existing systems, or ownership of the pipeline network, similar to the Tennessee Valley Authority electric utility.[63]

The second way is to increase the value of Section 45Q tax credit by 76%. This is potentially politically feasible, given recent bipartisan bills include an increase of the 45Q credit value from \$50/tonne CO_2 to \$85/tonne CO_2.[64,65] The third possibility is to reduce the power-plant investors' required ROR by 10 percentage points, from 15% to 5%, a type of regulation similar to the "allowed return on equity" in the utilities sector. The fourth option is to provide \$2.8 billion of direct subsidy to generators that have negative individual NPV. Those generators are identified by this study and the implementation is not difficult. Effectively, this subsidy is used to absorb the high capital cost in the early stage of learning for Allam-cycle generators.

4.3 Additional Policy Considerations

While a combination of policies could make this pipeline system economically feasible, they need to be implemented thoughtfully to lower the risk and overcome challenges such as the "chicken-and-egg problem": that there is no point in capturing CO_2, or even initiating development of a project, if there is nowhere to put it; at the same time, there is no point in building the CO_2 transport and storage infrastructure if there is no CO_2 to be transported and stored. For example, government investment in the CO_2 pipeline network could be carried out: (1) purely as low-cost financing to private developers, which may not be sufficient to solve the chicken-and-egg problem, or (2) with significant flexibility and risk tolerance above commercial loans to reduce the chicken-and-egg barrier, or (3) as direct government investment and ownership, in which the government would assume all chicken-and-egg risk.

In addition to reducing the chicken-and-egg risk, financing costs for initial carbon capture projects connecting to the pipeline network can be reduced by policies such as loan guarantees, direct loans, contract for differences, tax-exempt private activity bonds, and master limited partnerships. Those have been used or considered by governments around the world to support CCUS projects.[8,66] Besides direct incentives, broader policies such as carbon pricing could also improve the economics for CCUS project developers.

In this work, we assume a 20-year financial lifetime for Allam-cycle generators. Scenario 2 involves a 20-year Section 45Q tax credit, making it effectively a carbon pricing scenario where the value of the tax credit is the carbon price. Without the Section 45Q tax credit, our analysis shows that a carbon price of \$39/tonne CO_2 in 2030 (inflation-adjusted afterwards) will give our pipeline system a positive NPV and a \$78/tonne CO_2 carbon price would allow all individual Allam-cycle generators in the system to have positive NPV. With low-interest government financing of pipeline construction, the required carbon prices reduce to \$34/tonne CO_2 and \$72/tonne CO_2, respectively. These numbers are within the range of current carbon pricing discussions. For example, the minimum allowance price in California's cap-and-trade program is \$17.71/tonne CO_2-equivalent.[67] In the transportation sector, the compliance credit of California's Low Carbon Fuel Standard trades near \$200/tonne CO_2-equivalent.[68] In the building sector, New York City has put an emissions cap on its large buildings with a penalty of \$268/tonne CO_2-equivalent.[69]

In addition to carbon pricing, regulatory tools such as a clean energy standard, which mandates utilities increasingly produce electricity from non-CO_2-emitting power sources, or a performance standard for CO_2 emissions at the power-plant level, can improve the economic case for the Allam-cycle power-plant investors and benefit the CCUS system.

To conclude, results of our analysis show that the most impactful policies to enable the necessary infrastructure development include low-interest government loans on the order of \$20 billion for pipeline construction in this decade and an extended 20-year Section 45Q tax credit, or similar longer-term carbon price incentive. Additionally, supporting policies including government coordination, regulation, or direct ownership of pipelines and provision of direct subsidy to early Allam-cycle power plants may be necessary to enable the system to be developed. Such a system would provide significant reliable, dispatchable zero-emission power generation in the Midwestern and South-central United States.

This work highlights the importance of investments in CO_2 transport infrastructure in the near-term to enable substantial CO_2 emissions reductions and large-scale deployment of CCUS in the United States by 2050 and beyond. As a long-lived asset, this pipeline network connects major

CO_2 storage basins in the United States, providing substantial flexibility and accommodating different economic and energy-policy trajectories. Planning for the future by building pipelines with significant excess capacity can lower the unit cost of CO_2 transport for a later, more connected regional network, as proposed by Abramson et al. (2020)[27] and Larson et al. (2020).[5] Developing this proposed system would also position the United States at the forefront of CCUS technology and potentially open export markets for the Allam-cycle technology.

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