Supporting Information

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

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Other supplementary materials for the main manuscript include the following:

Exhibit S1.xlsx	The 10 spatiotemporal arrangements assessed in this work
Exhibit S2.xlsx	Summary of pipeline tariff and system-wide net present value
Exhibit S3.xlsx	Iterative analysis of the pipeline system
Model S1.xlsm	The model used to calculate pipeline tariff
Model S2.xlsm	The model used to calculate system-wide net present value

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1. Background

1.1 Section 45Q tax credit

Section 45Q of the United States tax code was originally enacted by the Energy Improvement and Extension Act of 2008 to provide a credit for the storage of CO_2. It was unsuccessful in promoting carbon capture, utilization, and storage (CCUS) activities for its first 10 years and was significantly reformed by the Bipartisan Budget Act of 2018. The revised Section 45Q now provides a tax credit on a per metric ton (tonne) basis for CO_2 that is captured and permanently stored or utilized. The owner of the CO_2 capture equipment is eligible to claim the tax credit and may transfer the credit to another party that stores or utilizes the CO_2. The value of the credit is differentiated into two categories: (1) secure geological storage in deep saline aquifers, and (2) secure geological storage resulting from enhanced oil recovery (EOR) projects. For saline aquifer storage, the applicable dollar amount was $22.66 per tonne of captured CO_2 in 2017 and increases linearly to $50 per tonne in 2026. For EOR, the credit was $12.83 per tonne CO_2 in 2017 with linear increases to $35 per tonne in 2026. The credit rate is adjusted for inflation after 2026. Capture facilities must begin construction by January 1, 2026 (extended from January 1, 2024 by the Taxpayer Certainty and Disaster Tax Relief Act of 2020) and can claim the credit for up to 12 years after being placed in service. Power plants need to capture at least 0.5 Mt CO_2 per year to qualify for the tax credit. For more details of the Section 45Q tax credit, the reader is directed to refs[1,2,64].

In this work, we assume the start-of-construction deadline for the Section 45Q tax credit will be extended indefinitely so that power generators with CO_2 capture equipment whose construction starts after the current start-of-construction deadline of January 1, 2026 can claim the 12-year tax credits. This assumption seems reasonable as multiple bills introduced in the 116th Congress (2019-2020) and 117th Congress (2021-2022) have proposed to extend the start-of-construction deadline, including one bill that proposed removal of the start-of-construction deadline.[65-67]

1.2 Allam power cycle

The Allam power cycle is a new oxy-fuel combustion cycle that uses supercritical CO_2 as the working fluid. It burns methane with pure oxygen and produces a pure stream of compressed CO_2, allowing for easy CO_2 capture. The key pieces of the cycle, including a combustor, a turbine, and a recuperating heat exchanger, were specifically developed for this technology, while other components were commercially available.[3] The theoretical Allam power cycle was introduced to the public in 2012 by NET Power,[3] whose current owners – 8 Rivers Capital, Exelon Corporation, McDermott International, and Oxy Low Carbon Ventures – are jointly commercializing it. A 50-MW-thermal grid-connected Allam-cycle demonstration plant achieved combustor first fire in Texas in May 2018 and is under operational testing since then.[4] A full-scale 300-MW-electric Allam-cycle commercial plant is currently in advanced design phase.[5] For a review of the development history and technical details of the Allam cycle, the reader is directed to publications from its developers.[3-10] For third-party assessments and potential applications of the Allam cycle, the reader is directed to refs[11-20]. Here we summarize Allam cycle's thermodynamic process and selected challenges associated with its development.[3-10] We also present estimates of Allam cycle's costs and cycle efficiency from the literature.

1.2.1 Thermodynamic process

In the combustor, methane is burned in a hot oxidant flow containing a mixture of supercritical CO_2 and pure oxygen to provide a high-pressure feed stream to the turbine. The feed stream expands through the turbine, generating electricity while reducing its pressure and temperature. At the turbine outlet, a recuperating heat exchanger transfers heat from hot turbine exhaust flow to a high-pressure recycle CO_2 stream, which flows back to the combustor from the later stage of this semi-closed-loop power cycle. After passing through the recuperating heat exchanger, the turbine exhaust flow is further cooled to near ambient temperature using an air or water cooler. At this stage, combustion-derived water condensates and is separated from the stream. The remaining stream, which is predominantly CO_2 and is the aforementioned CO_2 recycle stream, then enters the compression step, which involves multi-stage compressors, intercoolers, and multi-stage centrifugal pumps.

At some point during the compression step, a small portion (~5%) of the recycle steam is exported from the cycle to keep the system in mass balance. The removed CO_2 stream is of high purity and pressure and can be directly sent for geological sequestration or utilization through a CO_2 pipeline. Also during the compression step, a portion of the CO_2 recycle stream is mixed with oxygen produced by a collocated air separation unit (ASU) to form an oxidant stream. The oxidant stream and the primary CO_2 recycle stream are compressed separately through the rest of compression step. Both streams are heated (first by waste heat from ASU air compressors and then by the recuperating heat exchanger) and sent to the combustor. In the combustor, the oxidant stream is burned with methane while the primary CO_2 recycle stream dilutes the combustion product and thus decreases the temperature at turbine inlet to an appropriate level.

1.2.2 Selected challenges of development

A number of challenges may be associated with the development of Allam-cycle generators. First, it is challenging to ensure proper combustion of oxygen and methane in the presence of CO_2, which is normally used to extinguish fire. In the combustor, CO_2 makes up around 95% of the mass flow while oxygen and methane make up the remaining 5%.[7] Second, the combustor, turbine, and recuperating heat exchanger need to be newly developed to endure much more difficult working conditions than commercially available equipment. For example, the Allam-cycle combustor needs to withstand much higher pressure than existing gas turbine combustors. In addition, the Allam-cycle turbine needs to withstand pressure much higher than a gas turbine and temperature much higher than a steam turbine so its development needs to combine technologies from both gas and steam turbines. The Allam cycle's net efficiency depends on high turbine inlet temperature, which is constrained by the acceptable temperature of the recuperating heat exchanger located at the turbine outlet.[3] All of those essential pieces of equipment require specialized heat-resistant materials such as nickel alloy, specialized cooling strategies, and advanced manufacturing technologies.

Third, the recuperating heat exchanger network needs to be meticulously manufactured to provide a large specific surface area for high degree of heat recovery from the turbine exhaust flow to the CO_2 recycle flow, which is key to the high efficiency. Lastly, the Allam cycle's control system needs to be carefully designed to maintain the balance of heat transfer in the recuperating heat exchanger in a dynamic setting (as load varies during startup, operation, and shutdown of the power station).[6]

1.2.3 First-of-a-kind capital cost

A first-of-a-kind (FOAK) plant refers to the first commercial plant of a novel technology. Estimate of Allam cycle's FOAK capital cost is only available from Allam cycle's developer, NET Power, and is \$1851/kW.[21]

1.2.4 Nth-of-a-kind capital cost

Nth-of-a-kind (NOAK) capital cost indicates costs once the technology reaches maturity.

Table S1. Current estimates of Allam-cycle generator's NOAK capital cost in the literature.

Source of estimation	NET Power	IEAGHG (prepared by Amec Foster Wheeler Italiana)	UK Government (prepared by Amec Foster Wheeler, now Wood Group)	National Energy Technology Laboratory (USA)
Technology name	Allam cycle	"NET power cycle"	Allam cycle	"Natural gas direct supercritical CO_2 power cycle"
Year of publication	May 2015, in a commentary provided to ref[12]	August 2015	October 2018	March 2019
Description of the plant under modeling study	A power plant in the United States	Greenfield power plant in North East coast of the Netherlands	Greenfield power plant in North East coast of England	Greenfield power plant in the Midwestern United States
Estimates of NOAK capital cost	\$829-1250/kW with a median of \$1047/kW	Total plant cost = €1320/kW	Specific total project cost = £1430 /kW	Total plant cost = \$1471/kW
Currency in year	U.S. Dollar, year not specified	Euro, Q2 2014	British Pound, Q1 2017	U.S. Dollar, June 2011
Accuracy of estimate	Not available	Not available	-45/+45 percent	-15/+50 percent
Reference	[12]	[12]	[13]	[14]

Notes:

1. The power cycles investigated by refs[12-14] are not exactly the same as the proprietary Allam cycle developed by NET Power. Modeling parameters and assumptions vary.
2. The "total plant cost" from ref[12], the "specific total project cost" from ref[13], and the "total plant cost" from ref[14] were defined individually by the authors of the specific reports. They have similar but not exactly the same definition.

1.2.5 Cycle efficiency

Table S2. Current estimates of Allam cycle's efficiency in the literature. The numbers are based on lower heating value (LHV). LHV is a standard measurement of the heat of combustion of a fuel and assumes the produced water is in vapor state at the end of combustion.

Source of estimation	Technology name	Year of publication	Efficiency (based on lower heating value)	Reference
NET Power	Allam cycle	2013-2019	Target net efficiency = 58.9%	[3,5,6]
NET Power	Allam cycle	May 2015, in a commentary provided to ref[12]	Net electrical efficiency = 58.8%	[12]
IEAGHG (prepared by Amec Foster Wheeler Italiana)	"NET power cycle"	August 2015	Net electrical efficiency = 55.1%	[12]
UK Government (prepared by Amec Foster Wheeler, now Wood Group)	Allam cycle	October 2018	Net efficiency: * as new = 55.2% average = 52.3%	[13]
National Energy Technology Laboratory (USA)	"Natural gas direct supercritical CO_2 power cycle"	March 2019	Net plant efficiency = 53.4%	[14]
Scaccabarozzi et al.	Allam cycle	June 2016	Net electric efficiency = 54.58%	[15]
Mitchell et al.	Allam cycle	May 2019	Net cycle efficiency = 57.97%	[16]
Wimmer and Sanz	"NET power cycle"	June 2020	Net efficiency = 52.4%	[17]

Notes:

1. The power cycles investigated by refs[12-17] are not exactly the same as the proprietary Allam cycle developed by NET Power. Modeling parameters and assumptions vary.
2. The terms to describe cycle efficiency in refs[12-17] were defined individually by the authors of the specific reports. They have similar but not exactly the same definition.

* "As new" assumes zero degradation; "average" accounts for degradation across lifetime.

1.3 Recent policy proposals for CO_2 transport and storage infrastructure

The most recent policy initiatives on CCUS in the United States show strong support for CCUS development. In March 2021, the Storing CO_2 and Lowering Emissions (SCALE) Act was introduced in the U.S. Senate and the U.S. House of Representatives by a bipartisan group of members with broad support. Among other things, the SCALE Act would provide low-interest financing for CO_2 transport infrastructure and cost-sharing for deployment of commercial-scale CO_2 storage projects in saline aquifers.[22,23] U.S. President Biden plans to stress federal investments and enhance tax incentives for CCUS, and continue funding CCUS research, development, and demonstration.[24,25] For a review of CCUS policy in the United States, the reader is referred to reports from Congressional Research Service.[26-28]

Beyond the United States, governments around the world are acting to support the development of CO_2 transport and storage infrastructure. The Alberta Carbon Trunk Line, a shared CO_2 transport system with significant excess capacity, was completed in 2020 and was enabled by $550 million funding from the Canadian and Alberta governments.[29] The European Commission recently announced €135 million in funding to support six CO_2 transport and storage network projects in five European countries.[30] The Norway government recently announced $1.8 billion in funding for the Northern Lights shared CO_2 transport and storage project in the North Sea and two associated CO_2 capture projects.[31] The United Kingdom established an £800 million CCUS infrastructure fund to support the development of CO_2 transport and storage hubs.[32,33] Multiple hubs are under development, including Net Zero Teesside and Zero Carbon Humber. Australian governments are funding and leading the development of CarbonNet, a shared CO_2 transport and storage hub.[34]

2. Calculations

2.1 Cost differential between a first-of-a-kind Allam-cycle generator and a conventional natural-gas combined-cycle generator without carbon capture

2.1.1 Background

2.1.1.1 Time value of money

- Net present value of future payments $= \frac{F_1}{1+d} + \frac{F_2}{(1+d)^2} + \cdots + \frac{F_n}{(1+d)^n} = \sum_{i=1}^{n} \frac{F_i}{(1+d)^i}$, where d is the discount rate and n is the financial lifetime of an electricity-generating facility.
- Assume all future payments are the same: $F_1 = F_2 = \cdots = F_n = A$.
- Let I be today's investment cost. We have $I = A \times \sum_{i=1}^{n} \frac{1}{(1+d)^i} = A \times \frac{(1+d)^n - 1}{(1+d)^n \times d}$. Therefore, $A = I \times \frac{(1+d)^n \times d}{(1+d)^n - 1}$. $\frac{(1+d)^n \times d}{(1+d)^n - 1}$ is also called capital recovery factor, or CRF.

2.1.1.2 Levelized cost of electricity (LCOE)

- Equation (1): $\mathrm{LCOE} = \frac{\text{Total expenses per year}}{\text{Total electricity output per year}} = \frac{\frac{\mathrm{CapEx}}{\mathrm{yr}} + \frac{(\mathrm{O\&M})_{\mathrm{fix}}}{\mathrm{yr}} + \frac{(\mathrm{O\&M})_{\mathrm{var}}}{\mathrm{yr}}}{\frac{\text{Total electricity output}}{\mathrm{yr}}}$.
- Express each term of the numerator on the right hand side of Equation (1) as Equations (2)-(4).

- Equation (2): $\frac{\text{CapEx}}{\text{yr}} = \text{I} \times \text{CRF} = \text{I} \times \frac{(1+d)^n \times d}{(1+d)^n - 1}$.
- Equation (3): $\frac{(\text{O\&M})_{\text{fix}}}{\text{yr}} = \text{I} \times \text{fixed \%}$.
- Equation (4): $\frac{(\text{O\&M})_{\text{var}}}{\text{yr}} = \text{Fuel price} \times \frac{\text{Amt of fuel}}{\text{yr}} = \text{Fuel price} \times \frac{\text{Total electricity output}}{\text{Efficiency} \times \text{yr}}$.
- Plug Equations (2)-(4) into Equation (1), we get Equation (5).
- Equation (5): $\text{LCOE} = \frac{\text{I} \times \text{CRF} + \text{I} \times \text{fixed \%} + \text{fuel price} \times \frac{\text{Total electricity output}}{\text{Efficiency} \times \text{yr}}}{\frac{\text{Total electricity output}}{\text{yr}}} = \frac{\text{I} \times \text{CRF} + \text{I} \times \text{fixed \%}}{\text{Capacity} \times \text{Capacity factor} \times 8760 \text{ hrs}} + \frac{\text{Fuel price}}{\text{Efficiency}}$.
- Let $\text{I}_c = \frac{\text{I}}{\text{Capacity}} \; [=] \; \frac{\$}{\text{kW}}$, Equation (5) can be written as Equation (6).
- Equation (6): $\text{LCOE} = \frac{\text{I}_c \times \text{CRF}}{\text{Capacity factor} \times 8760 \text{ hrs}} + \frac{\text{I}_c \times \text{fixed \%}}{\text{Capacity factor} \times 8760 \text{ hrs}} + \frac{\text{Fuel price}}{\text{Efficiency}} \; [=] \; \frac{\$}{\text{KWh}}$.
- The three terms on the right hand side of Equation (6) correspond to "capital cost recovery," "O&M cost," and "fuel cost," respectively.

2.1.2 Methods

In 2018, NET Power estimated that the LCOE of "1×1 H CCGT" was $44/MWh, and the LCOE of "NET Power Pre-FEED Phase II (FOAK)" was around $62/MWh (see Table S3 for details).[35] Here, we first use the LCOE of "1×1 H CCGT" to postulate the value of parameters that NET Power used in their estimation. We then apply the same set of values to the LCOE of "NET Power Pre-FEED Phase II (FOAK)" to calculate the capital cost of a first-of-a-kind (FOAK) Allam-cycle generator.

Because we seek to determine the additional cost associated with replacing retiring coal-fired generators with Allam-cycle generators relative to the assumed replacement by conventional NGCC generators without carbon capture, we calculate the capital and operational cost differentials between an Allam-cycle generator and a NGCC generator without carbon capture in the last step.

Table S3. LCOE estimates of two power generating technologies from NET Power in 2018.[35]

Power-generating technology	LCOE ($/MWh)	Capital cost recovery ($/MWh)	O&M cost ($/MWh)	Fuel cost ($/MWh)
1×1 H CCGT	44	~15	~3	~26
NET Power Pre-FEED Phase II (FOAK)	~62*	~28	~6	~28

Note:
* This LCOE estimate does not take into account potential sales of captured CO_2 or sales of argon and nitrogen produced by the air separation process. Sales of those byproducts could reduce LCOE.

- Read from Table S3, LCOE = \$44/MWh for "1×1 H CCGT." Capital cost recovery ≈ \$15/MWh, O&M cost ≈ \$3/MWh, and fuel cost ≈ \$26/MWh. Using Equation (6), we obtain Equations (7)-(9).
- Equation (7): Capital cost recovery $= \frac{I_c \times \frac{(1+d)^n \times d}{(1+d)^n - 1}}{\text{Capacity factor} \times 8760 \text{ hrs}} \approx \$15/\text{MWh}$.
- Equation (8): O&M cost $= \frac{I_c \times \text{fixed } \%}{\text{Capacity factor} \times 8760 \text{ hrs}} \approx \$3/\text{MWh}$.
- Equation (9): Fuel cost $= \frac{\text{Fuel price}}{\text{Efficiency}} \approx \$26/\text{MWh}$.
- Given $I_c \approx \frac{\$1000}{\text{kW}}$ [36,37] and the LHV efficiency of General Electric's 1×1 H CCGT ≈ 62%,[13,16,38] we try different values of n, d, capacity factor, fixed %, and natural gas price to achieve Equations (7)-(9). It turns out that the following set of values,
    - $n = 30$ years,
    - $d = 10\%$,
    - capacity factor = 80%,
    - fixed % = 2.0%,
    - natural gas price $= \frac{\$4.69}{\text{MMBtu}} = \frac{\$1.6 \times 10^{-2}}{\text{KWh}}$,

  would give
    - $\frac{I_c \times \frac{(1+d)^n \times d}{(1+d)^n - 1}}{\text{Capacity factor} \times 8760 \text{ hrs}} = \text{capital cost recovery} = \frac{\$15.1}{\text{MWh}}$,
    - $\frac{I_c \times \text{fixed } \%}{\text{Capacity factor} \times 8760 \text{ hrs}} = \text{O\&M cost} = \frac{\$2.9}{\text{MWh}}$,
    - $\frac{\text{Fuel price}}{\text{Efficiency}} = \text{fuel cost} = \frac{\$25.8}{\text{MWh}}$.
- As a result, LCOE $= \frac{\$15.1}{\text{MWh}} + \frac{\$2.9}{\text{MWh}} + \frac{\$25.8}{\text{MWh}} = \frac{\$43.8}{\text{MWh}}$. This is close to NET Power's LCOE estimate for "1×1 H CCGT," which is \$44/MWh.

- Read from Table S3, LCOE ≈ \$62/MWh for "NET Power Pre-FEED Phase II (FOAK)." Capital cost recovery ≈ \$28/MWh, O&M cost ≈ \$6/MWh, and fuel cost ≈ \$28/MWh. Using Equation (6), we obtain Equations (10)-(12).
- Equation (10): Capital cost recovery $= \frac{I_c \times \frac{(1+d)^n \times d}{(1+d)^n - 1}}{\text{Capacity factor} \times 8760 \text{ hrs}} \approx \$28/\text{MWh}$.
- Equation (11): O&M cost $= \frac{I_c \times \text{fixed } \%}{\text{Capacity factor} \times 8760 \text{ hrs}} \approx \$6/\text{MWh}$.
- Equation (12): Fuel cost $= \frac{\text{Fuel price}}{\text{Efficiency}} \approx \$28/\text{MWh}$.
- We assume the Allam cycle has a LHV efficiency of 55% (see Section 1.2.5 of the supplementary text).
- We use the same values of n, d, capacity factor, fixed % and natural gas price as derived above for a FOAK Allam-cycle generator. To reiterate, those values are: $n = 30$ years,

$d = 10\%$, capacity factor $= 80\%$, fixed % $= 2.0\%$, and natural gas price $= \frac{\$4.69}{\text{MMBtu}} = \frac{\$1.6\times10^{-2}}{\text{KWh}}$.

- Let I_c of a FOAK Allam-cycle generator $= \boldsymbol{x}$. We have $\frac{\boldsymbol{x}\times\frac{(1+d)^n\times d}{(1+d)^n-1}}{\text{Capacity factor}\times 8760\text{ hrs}}$ = capital cost recovery ≈ 28/MWh. Therefore, $\boldsymbol{x} = \$1850/\text{kW}$.
- Check the following:
  - $\frac{I_c\times\text{fixed }\%}{\text{Capacity factor}\times 8760\text{ hrs}} = \text{O\&M cost} = \frac{\$5.3}{\text{MWh}} \approx \$6/\text{MWh}$. ✓
  - $\frac{\text{Fuel price}}{\text{Efficiency}} = \text{fuel cost} = \frac{\$29}{\text{MWh}} \approx \$28/\text{MWh}$. ✓
  - $\text{LCOE} = \frac{\$28}{\text{MWh}} + \frac{\$5.3}{\text{MWh}} + \frac{\$29}{\text{MWh}} = \frac{\$62.3}{\text{MWh}} \approx \$62/\text{MWh}$. ✓

2.1.3 Summary of results

- The FOAK capital cost for an Allam-cycle generator is estimated to be $1850/kW.
- (Δ capital cost) of "NET Power Pre-FEED Phase II (FOAK)" over GE's "1×1 H CCGT" $= \frac{\$1850}{\text{kW}} - \frac{\$1005}{\text{kW}} = \frac{\$845}{\text{kW}}$.
- (Δ operational cost_{fix}) of "NET Power Pre-FEED Phase II (FOAK)" over GE's "1×1 H CCGT" $= \frac{\$850}{\text{kW}} \times 2.0\% = \frac{\$17}{\text{kW}}$.
- (Δ operational cost_{var}) of "NET Power Pre-FEED Phase II (FOAK)" over GE's "1×1 H CCGT" is $\left(\frac{\text{Fuel price}}{\text{Efficiency}}\right)_{\text{Allam}} - \left(\frac{\text{Fuel price}}{\text{Efficiency}}\right)_{\text{GE}} = \frac{\frac{\$1.6\times10^{-2}}{\text{KWh}}}{55\%} - \frac{\frac{\$1.6\times10^{-2}}{\text{KWh}}}{62\%} = \frac{\$3.28}{\text{MWh}}$.

2.2 Impacts of extending Section 45Q tax credit on federal tax revenue

The longer, 20-year Section 45Q tax credit in Scenario 2 in the main text implies a larger cost for the federal government through reduced tax revenue, as compared to the 12-year Section 45Q tax credit in the base case. The 12-year Section 45Q tax credit implies on average $2.9 billion worth of tax credits are claimed by the Allam-cycle power-plant investors each year from 2030 to 2071. The 20-year Section 45Q tax credit implies on average $5.4 billion worth of tax credits are claimed each year from 2030 to 2079. To provide context, the federal government collected revenues of $3.5 trillion in 2019, including $230 billion from corporate taxes.[39,40] In 2017, federal tax incentives supporting renewable energy summed to $11.6 billion.[41] Estimates of annually utilized value of 12-year Section 45Q tax credit and 20-year Section 45Q tax credit throughout our study period are plotted in Figure S1. We note that Scenario 2 captures and stores 420 Mt more CO_2 than the base case. If that CO_2 is used in EOR operations, the increased oil production can create additional federal tax revenue on the order of $1 billion in total during the study period, insignificant as compared to the estimated reduction in federal tax revenue from base case to Scenario 2.

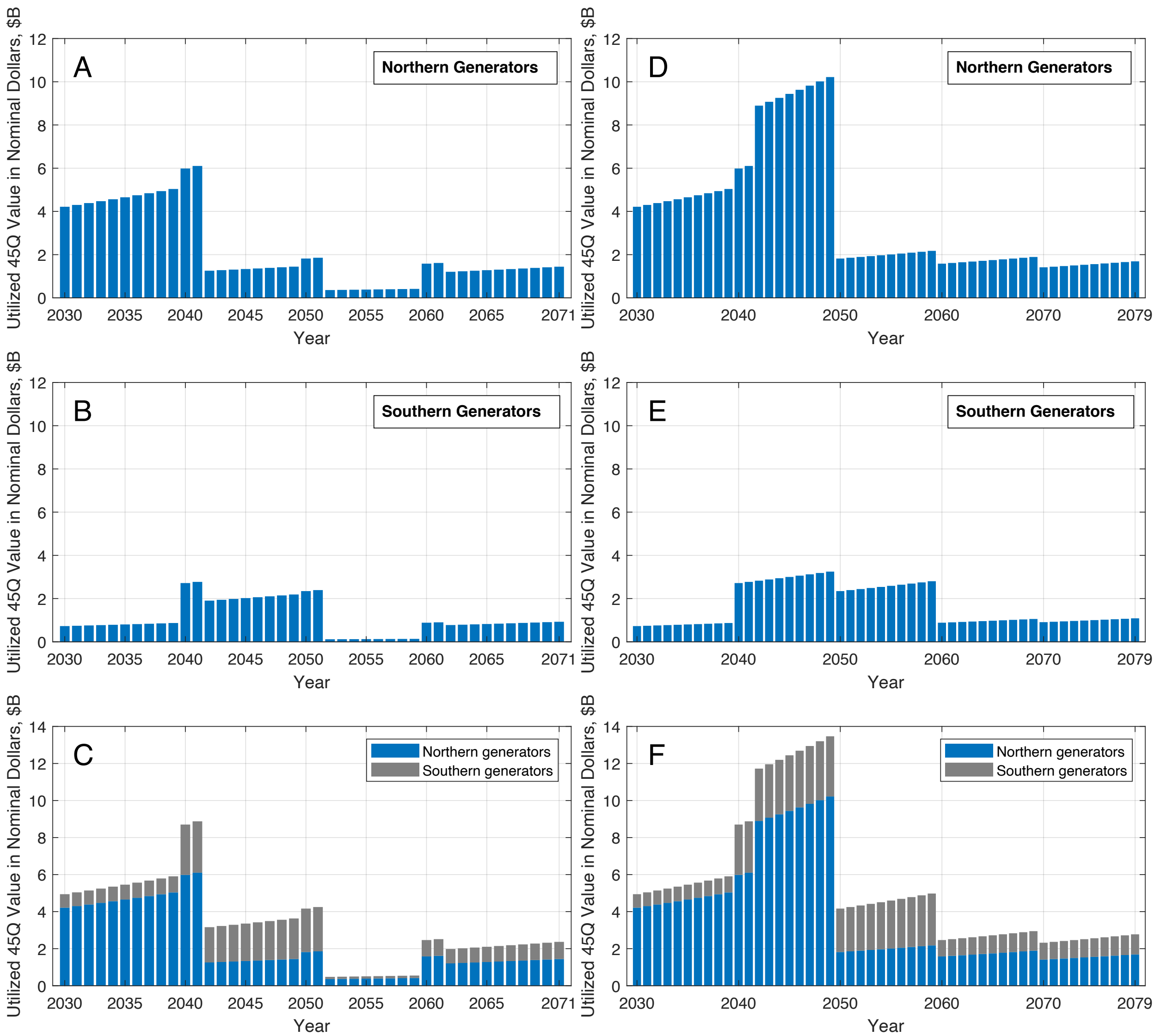

Figure S1. Estimates of annually utilized value of 12-year Section 45Q tax credit by the equity investors of (A) Northern generators, (B) Southern generators, and (C) both Northern and Southern generators. Estimates of annually utilized value of 20-year Section 45Q tax credit by the equity investors of (D) Northern generators, (E) Southern generators, and (F) both Northern and Southern generators. Values are in nominal dollars.

3. Materials and methods

Here we provide additional details related to the "Materials and Methods" section in the main text.

3.1 Power generator data

The CO_2 sources for the pipeline network were assumed to be natural gas-fired Allam-cycle power generators that are built at the same location as the current coal-fired power generators after their retirement, with the same generating capacity. We assumed coal-fired generators in our study region will retire at scheduled retirement dates as reported by U.S. Energy Information Administration,[42] or after 50 years of operation when scheduled retirement dates are unavailable. Fifty years is the average retirement age for coal-fired generators in the United States.[43]

We assumed an Allam-cycle generator has 100% CO_2 capture, 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,[44] and emits 450 kg CO_2 per MWh power generation.[45,46] This means the 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, collectively accounting for 100.3 GW of generating capacity and representing 40% of total coal-fired generating capacity in the United States. The Allam-cycle generators replacing those 156 coal-fired power generators form the basis of this analysis.

3.2 Pipeline network design

The pipelines were divided into segments, with each segment defined as the pipeline between successive junction points (that is, where two pipelines merge). At the overall inlet of the main trunk, which is the location furthest upstream in the pipeline flow system, the pressure was set to be 2100 psi, a typical compressor outflow pressure. At the outlet of the main trunk, which is at the CO_2 storage basin, the pressure was set to be 1400 psi, a typical oilfield delivery pressure. The pressure at each junction point along the main trunk (i.e., the pressure at the inlet and outlet of each main trunk segment) was calculated based on a linear pressure loss from the overall main trunk inlet to outlet. Feeder pipeline segments are shorter and have smaller CO_2 flow compared to main trunk segments. As a result, we assumed a uniform pressure drop of 200 psi between inlet and outlet for all feeder pipeline segments.

We calculated required CO_2 transport capacity of main trunk segments based on the maximum CO_2 flow through the segment during the study period. We picked out significant breaks in CO_2 flow rate between main trunk segments and grouped segments between the breaks as single main trunk section. Each main trunk section was modeled with uniform CO_2 flow rate equal to the maximum CO_2 flow rate occurs in the section. This results in slight oversize of most main trunk segments, providing expansion potential of CO_2 transport capacity and a conservative cost estimation.

Given the length, inlet and outlet pressure, and required CO_2 transport capacity of all pipeline segments, we used the U.S. Department of Energy NETL CO_2 Transport Cost Model[47] to calculate the required tariff (on a per-tonne-CO_2-transported basis) of using each pipeline segment, as well as the pipeline diameter and number of pump stations of each segment. In a pipeline segment, pump stations are needed if CO_2 pressure drops below the level of required outlet pressure within the segment. In this work, the average pump spacing is 29.3 miles per pump for the Northern main trunk and 27.5 miles per pump for the Southern main trunk. This spacing is smaller than natural gas pipelines (50-100 miles per pump)[48,49] but makes sense because high-pressure supercritical CO_2 is a denser fluid with higher viscosity than natural gas, leading to a higher rate of pressure drop in the pipeline. Our feeder pipeline segments have pump stations that are more than 10 miles apart.

3.3 Transport tariff for Allam-cycle generators

The years in which Allam-cycle generators are added to the pipeline system (in 10-year increments from 2030 to 2060), are subtracted from the system (at end of their designed operating life), or are re-assigned to a new CO_2 storage basin (when CO_2 storage capacity in the original basin has been fully utilized) are identified as "key years." In the key years, the amount of CO_2 flowing through the main trunk changes, which changes the required tariff for using the main trunk because tariff is defined on a per-tonne-CO_2-transported basis. We calculated the required tariff for each main trunk section and feeder pipeline segment in the key years, as shown in **Exhibit S2.xlsx**. The pipeline tariffs in other years were then based on the values in the key years, applying an inflation factor for the intervening years.

Because some Allam-cycle generators will only use part of a main trunk section, we distributed the tariff for each main trunk section amongst its constituent segments. The calculation was based on the ratio of a constituent segment's length relative to the main trunk section's length and the ratio of actual CO_2 flow rate through that constituent segment relative to the designed (maximum) CO_2 flow rate through the main trunk section. The calculations are shown in **Exhibit S2.xlsx**. Each generator uses and pays the tariff for a sequence of pipeline segments connecting it to the CO_2 storage basin.

3.4 Cost estimates for Allam-cycle generators

The Allam cycle represents a new technology. As a result, we modeled cost reductions between first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) Allam-cycle plants. Historically, the cost reductions associated with accumulated experience (i.e., the learning effect) is observed in many energy supply technologies such as pulverized coal plants, combined-cycle gas plants, and wind and solar PV plants, which might be attributed to, among others, cheaper input materials due to a maturing supply chain and economies of scale of production, gain in worker productivity with construction familiarity, and material science advances that increase combustion efficiency, according to Rubin et al. (2015).[50]

In this work, we applied the conventional log-linear learning curve to the capital cost of Allam-cycle generators. The learning curve takes the form $Y = ax^b$, where Y is the unit cost of energy supply technology, a is FOAK cost, and x is cumulative installed capacity. The parameter b is a constant such that $1-2^b$ is the learning rate, which is the fractional reduction in unit cost after a doubling of cumulative installed capacity.[50] Here we discuss each element of our learning curve in turn. System sensitivity to the learning curve is investigated in Section 5 of the supplementary text.

1. *FOAK capital cost*. We used two of Net Power's online presentations to estimate Allam-cycle generator's FOAK capital cost because that was the only available information.[21,35] From ref[35], a FOAK capital cost of \$1850/kW was estimated, and the calculation process is presented in Section 2.1 of the supplementary text. Ref[21] states a FOAK capital cost estimation of \$1851/kW. In this work, a FOAK capital cost of \$1850/kW is used.
2. *Learning rate*. The learning rate is defined as the fractional reduction in the unit cost of a technology for each doubling of the cumulative installed capacity.[50] For example, a learning rate of 10% means the capital cost will be 90% of FOAK capital cost when cumulative installed capacity doubles. In this work, the learning rate for Allam-cycle generators was estimated to be the same as the historical learning rate of NGCC generators, which is 10%.[50]
3. *Learning onset point*. The learning onset point refers to the amount of installed capacity needed before cost reductions due to learning take hold. Rubin et al. (2009)[51] used a learning curve to estimate future cost of power plants with CO_2 capture, and delayed the onset of learning to compensate the potential cost increase when initially combining different components of the power plant that have not yet been proven to work together. That high cost would then go down through learning, and the learning onset point was defined as the cumulative installed capacity at which the unit cost eventually reduces to the original cost estimate. Rubin et al. (2009)[51] assigned 3, 5, 7, and 10 GW as learning onset of NGCC, pulverized coal, integrated gasification combined-cycle, and oxy-fuel plants. Because the Allam cycle is one type of oxy-fuel cycles, we used 10 GW as the learning onset in this work.
4. *Learning end point*. The learning end point refers to the amount of installed capacity at which the learning effect ends. We used a learning end point of 100 GW. The value of 100GW was taken from the same Rubin et al. (2009)[51] study that we took the learning onset point from. Note that our pipeline system has 100.3 GW of Allam-cycle generators in total.
5. *NOAK capital cost*. Given the values of FOAK capital cost, learning rate, learning onset point, and learning end point, we were able to determine a unique learning curve. We read the NOAK capital cost of Allam-cycle generators from our learning curve as the capital cost at learning end point. Its value, \$1304/kW, is in the range of current estimates in the literature.[12-14]

We assumed there would be additional Allam-cycle deployment outside of our system, which only encompasses the Midwestern and South-central United States; the amount we assumed outside our system was the same amount as within our system, so that the learning would be expedited in the first 50 GW of our system and stay at that NOAK capital cost for the second 50GW. This is a reasonable assumption, given that (1) there is another 150 GW coal-fired power generating capacity in the United States, in addition to the 100.3 GW of coal capacity in our system,[42] (2) there is 140 GW of natural gas-fired power generating capacity in the United States that has exceeded or is less than 10 years away from the average retirement age of 35 years,[42,43] and (3) NET Power is expanding in countries like the United Kingdom and New Zealand.[52,53] Those power generating capacity might deploy Allam cycle in the similar timeframe as our pipeline system. In Section 5 of the supplementary text, we explore system sensitivity to scenarios in which there is no or more deployment of Allam cycle outside of our pipeline system.

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 Financial parameter assumptions

Table S4. Financial parameter assumptions in this work. Values in 2020 dollars are projected to future years using inflation rate.

#	Parameter	Value
1	Tax rate (federal corporate rate + others)	24%
2	Annual inflation rate	2%
3	Pipeline depreciation schedule	150% declining balance 15-year
4	Allam-cycle generator depreciation schedule	MACRS 5-year
5	Pipeline capital expanding duration (construction period)	4 years
6	Allam-cycle generator capital expanding duration (construction period)	2 years
7	Oil-linked CO_2 sales price to EOR operations	\$23/tonne CO_2 in 2020 dollars
8	CO_2 saline storage cost in the Illinois Basin[54]	\$12.5/tonne CO_2 in 2020 dollars
9	CO_2 saline storage cost in the Gulf Coast[54]	\$9.5/tonne CO_2 in 2020 dollars
10	Natural gas price	\$4.69/MMBtu in 2020 dollars
11	Capital cost of conventional NGCC generator without carbon capture[37]	\$1005/kW in 2020 dollars

Notes:

1. We used a natural gas price of \$4.69/MMBtu as the fuel price for Allam-cycle generators. This value is higher than the current Henry Hub natural gas spot price, which is around \$3/MMBtu.[55] It therefore provides a conservative cost estimate for our pipeline system. In Section 4.1 of the main text, a sensitivity analysis is presented on natural gas price.
2. We assumed an oil-linked CO_2 sales price of \$23 per tonne CO_2 to EOR operations during the study period, corresponding to an crude oil price of around \$60 per barrel. This oil price is consistent with current forecasts of Brent crude oil price from now to 2050, which are in the range of \$55-\$95 per barrel.[56-58] The World Bank predicts an oil price of \$70 in 2030.[59] The West Texas Intermediate Crude Oil futures are currently trading at \$50 per barrel for delivery in 2030.[60,61]

4. Base case

4.1 Assumptions

In this work, we assumed an Allam-cycle generator needs financial incentives to continue its operation because the baseline replacement of coal capacity is by NGCC generators without carbon capture. The financial incentives can come from CO_2 sales to EOR operations, monetized Section 45Q tax credit, or both. The financial lifetime (i.e., the payback period) of an Allam-cycle generator was set to be the same as its operational lifetime with a maximum of 20 years. The operational lifetime of an Allam-cycle generator was between 12 and 40 years. The 40-year operational lifetime is consistent with global average lifetime for gas-fired power generators.[62]

We assumed the pipeline network operates as long as there is a demand for CO_2 transport from Allam-cycle generators. Well-constructed and maintained CO_2 pipelines can have operational lifetimes well above our 42-year study period.[63] For a main trunk segment, its financial lifetime was set to be the same as its operational lifetime with a maximum of 30 years. A feeder pipeline has the same financial lifetime as the generator to which it is connected. In the rest of this section, IB refers to “Illinois Basin,” GC refers to “Gulf Coast,” and PB refers to “Permian Basin.”

4.2 Selection of the base case

We designed 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). From the perspective of Allam-cycle power-plant investors, utilizing nearby CO_2 storage basins means lower cost of transport, but connecting to a farther CO_2 storage basin may unlock larger financial incentives. For example, the Northern Allam-cycle generators can only earn Section 45Q tax credit minus saline storage cost if sending CO_2 to IB saline, which is close to them, but can earn both the Section 45Q tax credit and CO_2 sales revenue if sending CO_2 to GC EOR, which is farther away from them.

The trade-off between larger financial incentive and longer distance of CO_2 transport, together with the complications from an evolving pipeline system (with Allam-cycle generators coming online and offline, and switching to other CO_2 storage locations after storage capacity in the original location is fully utilized, etc.), required us to analyze each spatiotemporal arrangement individually. As shown in Table S5, all permutations of our study region and system can be distilled to ten cases. We analyzed all 10 arrangements and reported their NPV results in Table S6. Further details of the 10 arrangements are presented in **Exhibit S1.xlsx**.

Table S5. Spatiotemporal arrangements considering two groups of Allam-cycle generators (i.e., Northern and Southern groups) and four subsurface CO_2 storage options: IB saline, GC saline, GC EOR, and PB EOR. Ten arrangements, representing all 50 of those, were analyzed in this work. Note that the other 40 arrangements are infeasible for the reasons given in the footnotes.

#	Arrangement		Notes		Analyzed in this work?
	Northern generators	Southern generators	North	South	
1	IB saline	PB EOR			Yes
2	IB saline	PB EOR + GC EOR		12*	-
3	IB saline	PB EOR + GC saline		12*	-
4	IB saline	GC EOR		1*	-
5	IB saline	GC EOR + PB EOR		13*	Yes
6	IB saline	GC EOR + GC saline			Yes
7	IB saline	GC saline		2*	Yes
8	IB saline	GC saline + PB EOR		3*	-
9	IB saline	GC saline + GC EOR			Yes
10	IB saline + GC EOR	PB EOR			Yes
11	IB saline + GC EOR	PB EOR + GC saline		12*	-
12	IB saline + GC EOR	GC saline			Yes
13	IB saline + GC EOR	GC saline + PB EOR		3*	-
14	IB saline + GC saline	PB EOR	4*		-
15	IB saline + GC saline	PB EOR + GC EOR	4*	12*	-
16	IB saline + GC saline	GC EOR	4*	1*	-
17	IB saline + GC saline	GC EOR + PB EOR	4*		-
18	IB saline + PB EOR	GC saline		3*	-
19	IB saline + PB EOR	GC saline + GC EOR		3*	-
20	IB saline + PB EOR	GC EOR		1*	-
21	IB saline + PB EOR	GC EOR + GC saline		3*	-
22	GC EOR	PB EOR	10*		-
23	GC EOR	PB EOR + GC saline	10*	12*	-
24	GC EOR	GC saline	10*		-
25	GC EOR	GC saline + PB EOR	10*	3*	-
26	GC EOR + IB saline	PB EOR			Yes
27	GC EOR + IB saline	PB EOR + GC saline		12*	-
28	GC EOR + IB saline	GC saline			Yes

29	GC EOR + IB saline	GC saline + PB EOR		3*	-
30	GC EOR + GC saline	PB EOR	5*		Yes
31	GC EOR + PB EOR	GC saline		3*	-
32	GC saline	PB EOR	6*		-
33	GC saline	GC EOR		1*	-
34	GC saline	GC EOR + PB EOR	7*		-
35	GC saline + IB saline	PB EOR	8*		-
36	GC saline + IB saline	PB EOR + GC EOR	8*	12*	-
37	GC saline + IB saline	GC EOR	8*	1*	-
38	GC saline + IB saline	GC EOR + PB EOR	8*		-
39	GC saline + GC EOR	PB EOR	9*		-
40	GC saline + PB EOR	GC EOR		1*	-
41	PB EOR	GC EOR	11*	1*	-
42	PB EOR	GC EOR + GC saline	11*	3*	-
43	PB EOR	GC saline	11*	3*	-
44	PB EOR	GC saline + GC EOR	11*	3*	-
45	PB EOR + IB saline	GC EOR		1*	-
46	PB EOR + IB saline	GC EOR + GC saline		3*	-
47	PB EOR + IB saline	GC saline		3*	-
48	PB EOR + IB saline	GC saline + GC EOR		3*	-
49	PB EOR + GC EOR	GC saline		3*	-
50	PB EOR + GC saline	GC EOR		1*	-

Notes:

1* GC EOR on itself does not have enough CO_2 storage capacity for the Southern generators for the entire study period.

2* This arrangement is less economically attractive than Arrangement #9 because the generators would have shorter operational and financial lifetimes (no financial inventive after the 12th year) and there would be no revenue from selling CO_2 to EOR operations. However, we still analyze this arrangement as an example that only uses saline storage (with no EOR).

3* This arrangement is impossible because the main trunk connecting PB and GC, which is referred to as the PB-GC main trunk, cannot simultaneously transport CO_2 in both eastward and westward directions. As an example, in Arrangement #8, the Southern "2030 group" generators would need to use PB-GC to transport CO_2 westward to PB EOR after the 12th year but the Southern "2040 group" generators along PB-GC are still sending CO_2 eastward to CG saline at that time.

4* This arrangement is impossible because generators can only claim Section 45Q tax credit for up to 12 years. There is no financial incentive for the Northern generators to do GC saline after doing IB saline for 12 years.

5* The cost of CO_2 storage in GC saline is lower than it is in IB saline due to more favorable geological conditions.[54] This lower storage cost, however, does not justify the long-distance transport for the Northern generators to choose GC saline over IB saline. As shown in Table S6, this arrangement has worse NPV than Arrangement #26.

6* This arrangement is less economically attractive than Arrangement #1 because GC saline is farther than IB saline for Northern generators.

7* This arrangement is less economically attractive than Arrangement #5 because GC saline is farther than IB saline for Northern generators.

8* This arrangement is impossible because generators can only claim Section 45Q tax credit for up to 12 years. There is no financial incentive for the Northern generators to do IB saline after doing GC saline for 12 years.

9* This arrangement is less economically attractive than Arrangement #10 because GC saline is farther than IB saline for Northern generators.

10* GC EOR on itself does not have enough CO_2 storage capacity for the Northern generators for the entire study period.
11* PB EOR on itself does not have enough CO_2 storage capacity for the Northern generators for the entire study period.
12* PB EOR on itself has enough CO_2 storage capacity for the Southern generators for the entire study period. It does not make sense to add GC EOR or GC saline after PB EOR.
13* There is a reversal of flow in the PB-GC main trunk for the Southern system after CO_2 storage capacity in GC EOR is fully utilized.

Table S6. Specifications and NPV results of the ten assessed arrangements. System-wide NPV considers both Northern and Southern pipeline systems. NPV is in 2020 dollars.

#	Arrangement		Total CO_2 stored from year 2030 to 2071 (EOR : saline) (Mt)	System-wide NPV ($B)	Rank	System-wide NPV per tonne CO_2 stored ($)	Rank
	North	South					
1	IB saline + GC EOR	PB EOR	5332 (7:3)	-6.07	*3*	-1.14	*2*
2	IB saline + GC EOR	GC saline	3981 (3:7)	-9.44	*7*	-2.37	*6*
3	IB saline	GC saline + GC EOR	3960 (3:7)	-9.50	*8*	-2.40	*7*
4	IB saline	GC saline	2610 (0:10)	-10.91	*10*	-4.18	*10*
5	IB saline	GC EOR + GC saline	3331 (4:6)	-5.88	*2*	-1.76	*4*
6	IB saline	GC EOR + PB EOR	3960 (6:4)	-6.75	*4*	-1.70	*3*
7	IB saline	PB EOR	3960 (6:4)	-7.53	*5*	-1.90	*5*
8	GC EOR + IB saline	PB EOR	3960 (9:1)	-4.29	*1*	-1.08	*1*
9	GC EOR + IB saline	GC saline	2610 (5:5)	-7.66	*6*	-2.94	*9*
10	GC EOR + GC saline	PB EOR	3960 (9:1)	-10.32	*9*	-2.61	*8*

As seen in Table S6, Arrangement #8 has the most favorable overall NPV as well as most favorable NPV per tonne of CO_2 stored (note that different arrangements store different amounts of CO_2). We therefore use it as the base case. Note that while Arrangement #8 is most favorable, it is still not profitable because NPV is negative (as it is in all arrangements – Arrangement #8 is least negative).

Table S6 also shows that arrangements starting with EOR generally have better NPV than arrangements starting with saline storage. If a generator starts with EOR, its financial incentive includes both Section 45Q tax credit for EOR (up to \$35/t CO_2) and CO_2 sales to EOR operations (~ \$20/t CO_2), the sum of which exceeds the value of Section 45Q tax credit for saline storage (up to \$50/t CO_2). However, its operational lifetime (hence the financial lifetime or the payback period) is limited to 12 years because it has no incentive to do saline storage after the 12-year Section 45Q tax credit period. If a generator starts with saline storage, it has smaller financial incentive during the first 12 years but can continue operating after the 12th year by selling CO_2 to EOR operations, assuming the EOR storage capacity is preserved during the first 12 years. Our analysis reveals that having larger financial incentive in the early years of operation improves the economics of generators, despite shorter payback period. One extreme example is Arrangement #4 in Table S6, which does not use EOR storage and has the least favorable NPV of the ten assessed arrangements.

We also observe that, although the cost of saline storage is lower in the Gulf Coast compared to the Illinois Basin,[54] the cost of CO_2 transport makes it economically unfavorable for the Northern generators to do saline storage in the Gulf Coast as compared to saline storage in the Illinois Basin. This can be seen when comparing Arrangement #8 with Arrangement #10 in Table S6. Finally, we note that the NPV of all arrangements in Table S6 are on the same order of magnitude. This means the policy analysis on Arrangement #8 (i.e., the base case) in this work can potentially be applied to other arrangements as well.

4.3 Description of the base case

In the base case, the Northern Allam-cycle generators first use GC EOR and then use IB saline for CO_2 storage. The Southern Allam-cycle generators only use PB EOR. Let the group of generators with online year of 2030 be referred to as the Red group. Similarly, we call the groups for generators with online years of 2040, 2050, and 2060 the Orange, Yellow, and Green groups, respectively. Figure S2 shows the pipeline system in the base case.

We start with the Northern system. In 2030, the Red group will be online. 111.3 Mt/yr CO_2 (as shown in Table 1 in the main text) is sent to the Gulf Coast to be used in EOR operations. The economic incentives for the Red group include CO_2 sales price for EOR operations as well as the Section 45Q tax credit. In 2040, the Orange group will be online and 18.3 Mt/yr CO_2 is also sent to the Gulf Coast for EOR. The Orange group has the same economic incentive as the Red group until the end of 2041, when the EOR capacity in the Gulf Coast (1.5 Gt CO_2, shown in Figure 1B in the main text) is fully utilized. Starting in 2042, the Red group has the option to send CO_2 to the Illinois Basin for saline storage. However, the Red group will not do that because they have no economic incentive to do so: there is no CO_2 sales price for saline storage and their Section 45Q tax credit, which lasts 12 years for each generator, has expired. As a result, the Red group stop operation and disconnect themselves from the pipeline.

The Orange group continue operation and send CO_2 to the Illinois Basin for saline storage since they will have 10 more years of Section 45Q tax credit. The Orange group will stop operation and disconnect at the end of 2051, when their tax credit expires. In 2050, the Yellow group will be online and will directly send CO_2 to the Illinois basin for saline storage because there is no storage capacity for EOR in the Gulf Coast. They will stop operating after 12 years, at the end of their 12-year Section 45Q tax credit. The Green group will be operating for 12 years from 2060 to 2071 as designed. All four groups of generators in the Northern system have operational and financial lifetimes of 12 years.

In the Southern system, the Red group will come online in 2030. 19.2 Mt/yr CO_2 flow is sent to the Permian Basin for EOR operations. From 2030 to 2041, the economic incentive for the Red group includes CO_2 sales price and Section 45Q tax credit, the same as in the Northern system. However, unlike in the Northern system, the Red group in the Southern system will continue operation after 2041 because, although the Section 45Q tax credit expires in 2041, they can still sell CO_2 to the EOR operations after 2041, assuming oil demand and EOR operators' willingness to pay for CO_2 remain sufficient during the study period. The Orange, Yellow, and Green groups in the Southern system follow the same patterns as the Red group, continuing operation after the first 12 years of Section 45Q tax credit and will all stop operation in 2071, at the end of study period. The Red, Orange, Yellow, and Green groups in the Southern system will have operational lifetimes of 40, 32, 22, and 12, respectively, and financial lifetimes of 20, 20, 20, and 12 years, respectively. Some operational lifetime and financial lifetime are curtailed because our study period ends in 2071.

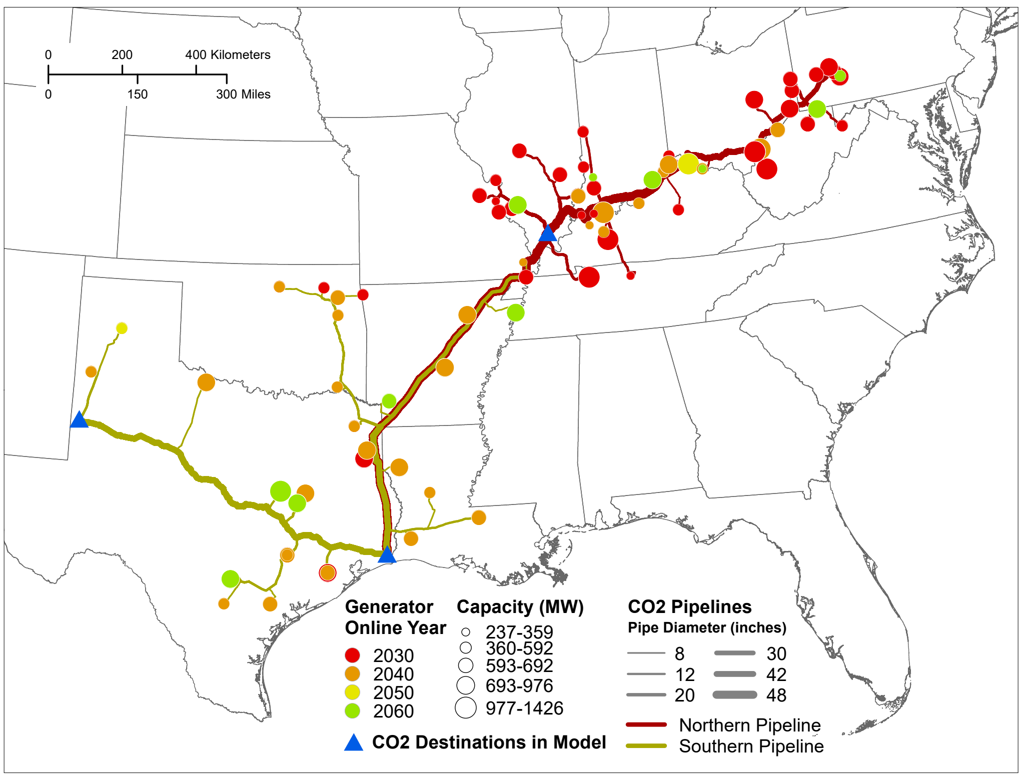

Figure S2. Illustration of the pipeline system in the base case. Allam-cycle generators with different online years are shown in different colors. Size of the circle reflects nameplate capacity.

4.4 Levelized costs and benefits for all Allam-cycle generators

We calculated the levelized costs and benefits for all Allam-cycle generators in our system. For an Allam-cycle generator, its levelized costs and benefits were calculated by dividing the present value of that generator's costs and benefits over its financial lifetime by the total amount of CO_2 it captured and stored over the financial lifetime (also discounted to the present time).[68] Results are shown in Figure S3.

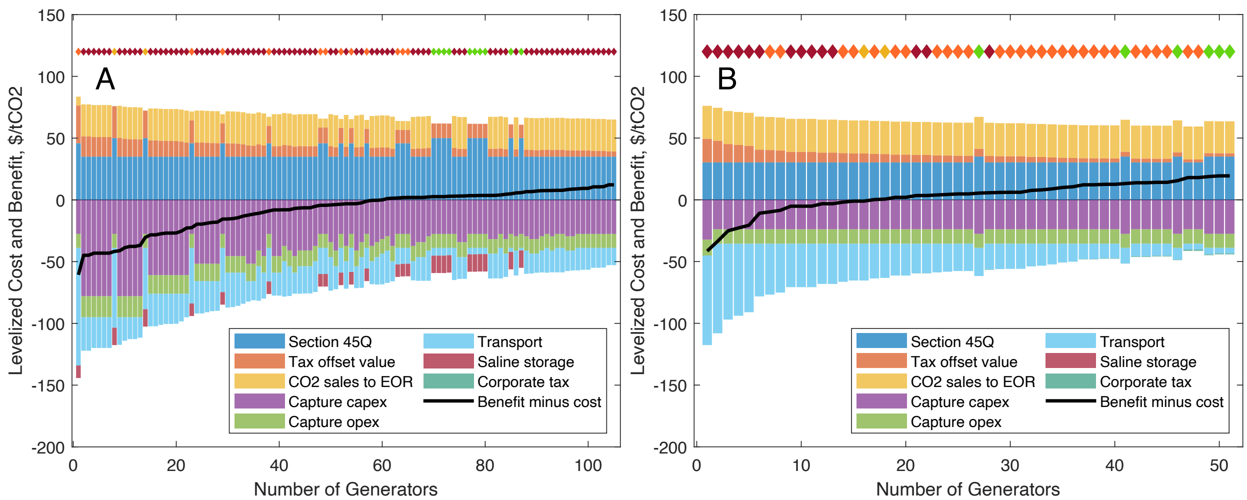

Figure S3. Levelized costs and benefits for individual Allam-cycle generators in (A) the Northern system and (B) the Southern system in the base case. Red, orange, yellow, and green diamonds indicate generator online years of 2030, 2040, 2050, and 2060, respectively. Width of the bars and size of the diamonds have no meanings. Values are in 2020 dollars.

Table S7 shows cost breakdown for 4 types of Allam-cycle generators: (1) built early (higher capital cost) and far from the CO_2 storage basin, (2) built late (lower capital cost due to the learning effect) and far from the storage basin, (3) built early and close to the storage basin, and (4) built late and close to the storage basin. For simplicity, we took samples only from the 2030 (red) generator group in the Northern system (red-diamond bars in Figure S3A) for this demonstration. The capital cost of Allam-cycle generators varies within the red group based on the generator's expected online date and the associated learning that had taken place by that time.

Table S7. Cost breakdown for four types of 2030 (red) group Allam-cycle generators in the Northern system. Values are in 2020 dollars.

	Built early & far from CO_2 storage basin	Built late & far from CO_2 storage basin	Built early & near CO_2 storage basin	Built late & near CO_2 storage basin
Example	2nd bar from left side of Figure S3A	23rd bar from right side of Figure S3A	13th bar from left side of Figure S3A	1st bar from right side of Figure S3A
Total levelized cost ($/t$CO_2$)	122.17	63.64	111.58	52.88
Capture capex ($/t$CO_2$)	78.01 (64% of total)	27.57 (43% of total)	78.01 (70% of total)	27.57 (52% of total)
Capture opex ($/t$CO_2$)	16.99 (14% of total)	11.31 (18% of total)	16.99 (15% of total)	11.31 (21% of total)
Transport cost ($/t$CO_2$), including	27.17 (22% of total)	24.74 (39% of total)	16.58 (15% of total)	13.91 (26% of total)
Main trunk transport ($/t$CO_2$)	22.65	21.08	15.06	13.91
Feeder line transport ($/t$CO_2$)	4.52	3.66	1.52	0.00

5. System sensitivity to Allam-cycle generator's learning curve

We conducted a sensitivity analysis to see how changes in the input parameters to the power-plant investor's financial model would change system-wide NPV. We focus on the shape of Allam-cycle generators' learning curve because this turns out to have a major impact on the NPV results both individually and collectively.

In this work, we applied a log-linear learning curve to model the initial decrease in the capital cost of Allam-cycle generators with cumulative installed capacity. Here we call the learning curve that is used in our analysis the "original learning curve" and investigate 9 variations of it, changing one component of the curve at a time. Specifications of the original learning curve and its 9 variations are given in Table S8, and their shapes are plotted in Figure S4A. We did not investigate a learning case variation with lower FOAK capital cost because the FOAK capital cost in the original learning curve, unlike values of other elements that were taken from the third party,[50,51] was only available from NET Power. We believed that represents the most optimistic estimate of Allam-cycle generator's FOAK capital cost. The range of NOAK capital costs in Table S8 is close to estimates reported in the literature.[12-14] This indicates our sensitivity model covers the likely range of the learning curve. The NPV results corresponding to the three financing scenarios (i.e., base case, Scenario 1, and Scenario 2), each calculated using the original learning curve and its 9 variations, are plotted in Figure S4B.

Table S8. Specifications of the original learning curve (case 0) and its 9 variations (cases 1-9).

Case		FOAK capital cost ($/kW)	Learning rate	Learning onset (GW)	Learning end (GW)	Simultaneous Allam-cycle deployment outside of our system	Resulting NOAK capital cost ($/kW)
0	Original learning curve	1850	10%	10	100	100%	1304
1	No outside deployment	1850	10%	10	100	0%	1304
2	Double outside deployment	1850	10%	10	100	200%	1304
3	Large learning rate	1850	15%	10	100	100%	1078
4	Small learning rate	1850	5%	10	100	100%	1560
5	Early learning onset	1850	10%	5	100	100%	1173
6	Late learning onset	1850	10%	15	100	100%	1386
7	High FOAK	2220	10%	10	100	100%	1564
8	Early learning end	1850	10%	10	75	100%	1449
9	Late learning end	1850	10%	10	125	100%	1226

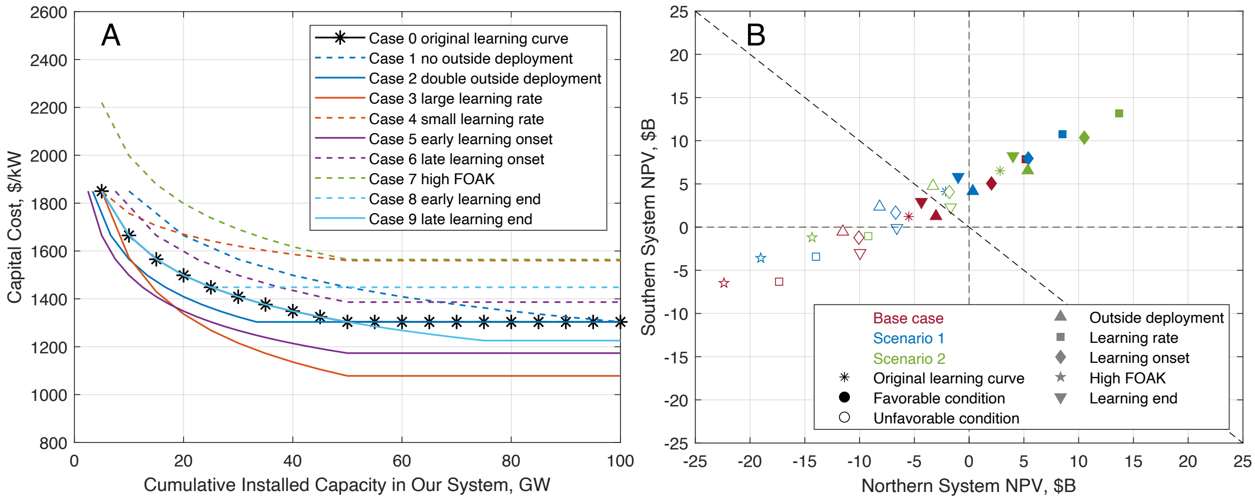

Figure S4. (A) Shape of the original learning curve and its 9 variations. (B) System-wide NPV evaluated using the original learning curve and its 9 variations under three financing scenarios (i.e., base case, Scenario 1, and Scenario 2). The horizontal and vertical dash lines indicate an NPV of zero. The region to the right of the diagonal contains cases whose system-wide NPV is positive when considering both Northern and Southern systems. NPV is in 2020 dollars.

Figure S4B plots NPV results corresponding to the three financing scenarios listed in Table 2 in the main text. The horizontal and vertical axes show NPV results of the Northern and Southern systems, respectively. NPV results of different financing scenarios are shown in different colors and variations of the learning curve are indicated by different marker shapes. Within each variation, a solid marker refers to a favorable change of the learning curve (e.g., higher learning rate, earlier learning onset, and later learning end) and a hollow marker refers to an unfavorable change of the learning curve. Markers in the upper right quadrant indicate the corresponding cases have positive NPV in both Northern and Southern systems. Cases whose markers are located to the right of the diagonal have positive NPV for the overall pipeline system (considering both Northern and Southern systems) and are deemed to be economically viable.

Figure S4B shows that higher learning rate (solid square markers) and earlier learning onset (solid diamond markers) improve system-wide NPV the most because they lead to lower NOAK capital cost. Also, a 20% higher FOAK capital cost would make the system significantly less economical, as seen by the three hollow stars in the left region of Figure S4B. This illustrates the importance of FOAK capital cost in our analysis. We also observe that in a favorable financing scenario, some unfavorable variations of the learning curve can still give the overall system a positive NPV. For example, the green hollow upward-pointing triangle, green hollow downward-pointing triangle, and green hollow diamond are in the economically viable region. Finally, we note that none of the learning curve variations investigated here can give all Northern generators positive individual NPV, because every result shown in Figure S4B involves at least one generator with a negative individual NPV. Therefore, the policy options considered in Sections 4.2 and 4.3 of the main text need to be applied to enable the pipeline system to be developed.

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