Supporting Information for *Natural Gas versus Electricity for Solvent-Based Direct Air Capture*

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1. A Brief History of Solvent-Based Direct Air Capture (DAC)

The concept of DAC was first proposed as a climate change mitigation technology by Klaus Lackner in 1999 (Lackner, Ziock, and Grimes 1999). Since then, multiple types of DAC have been and are being developed, including solvent-based, solid sorbent-based, and mineralization-based. For solvent-based DAC, there have been multiple analyses that evaluate the cost of such a system. Some of the analyses presented in the literature are outlined in Table S 1 along with the varying economic assumptions and costs that compose these cost estimates. All these analyses use natural gas as the thermal energy resource in an oxy-fired calciner, further indicating the importance of analysing DAC integrated to varying energy resources.

Table S 1: Major Economic and Capital Differences Between Previously Reported Solvent-Based DAC Costs

	American Physical Society (2011)	Mazzotti et al., (2013)	Zeman (2014)	Keith et al. (2018)	NASEM (2019)
Net Removed Cost Projection [$/tCO$_2$]	641 – 891	510 – 568*	309 – 580†	168 – 232‡	199 – 357§
Plant Lifetime [years]	20	20	20	25	30
WACC¶	10.3%	10.3%	10.3%	5.5% and 11.7%	11.5%
Lang Factor	4.5 – 6#	4.5	4.5	3.2‖	1.5 – 4.5**
Capacity Factor	90%	90%	90%	90%	100%
Contactor Configuration	Counter-Flow	Counter-Flow	Counter-Flow	Cross-Flow	Cross-Flow
Packing Materials	Mellapak-250Y	Mellapack-250Y Mellapak-500Y Mellapak-CC	Mallapak-250Y PVC-Based	PVC-Based	Stainless Steel PVC-Based††
Solvent Solution	NaOH	NaOH	NaOH	KOH	KOH
Thermal Energy Resource	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Calciner Technology	Oxy-fired	Oxy-fired	Oxy-Fired	Oxy-fired	Oxy-fired

*The $510/tCO$_2$ value corresponds to a novel Sulzer packing material created specifically for carbon capture (Mellapak-CC). The high-end cost ($568/tCO$_2$) corresponds to the Mellapak-250Y packing.

† This range corresponds to varying scenarios presented by Zeman. The low-end cost ($309/tCO$_2$) corresponds to a scenario with an onsite NGCC facility with CCS combined with heat integration and PVC-based packing. The high-end cost corresponds to a base case scenario consistent with that presented in the APS report. with a different energy load (calculations for energy load are shown within the paper).

‡ The costs reported here are consistent with scenario A in the cited report at 7.5% and 12.5% annual capital recovery, respectively.

§The cost range reported here is based on the natural gas scenario in the report with electricity sourced from the grid.

¶Weighted Average Cost of Capital (WACC) from combined equity and debt capital

#For new technology such as DAC, a factor of 6 is used to account for uncertain scope and extra requirements of commercial scale plants. An installed factor of 4.5 was used for the optimistic case, where an installed factor of 6 was used for the realistic case.

‖ Costs reported in Keith et al. are based on engineering firm estimates using some results from pilot plant operation. The Lang factor presented here was back calculated as the ratio of the total installed cost (M$1,126.8) to the sum of the major equipment costs (M$347) (includes all equipment costs except other equipment and buildings).

**An installed factor of 1.5 was used for mature industrialized technologies (such as the slaker, causticizer, clarifier) and 4.5 for newer, less industrialized developments (such as the oxy-fired calciner).

††This report presents a range for the cost associated with the capital equipment required for the process. Here, PVC-based packing was used for the low-end contactor cost and stainless steel for the high-end cost.

2. System and Economic Assumptions

In the analysis, the following system and economic assumptions have been made consistently across all process scenarios (shown in Table S 2).

Table S 2: Table of baseline assumptions for analysis

Parameter	Assumed Value	Reasoning
Capacity [tCO_2/year]	1,000,000	Consistent with NASEM (2019)
Weighted Average Cost of Capital (WACC)	8.5%	
Economic Lifetime [years]	20	
Capital Recovery Factor (CRF)	0.1057	
Concentration of CO_2 in Air [ppmv CO_2]	400	Consistent with (National Academy of Sciences Engineering and Medicine 2019)
Capture Fraction from Air	VF: 50% HF: 75%	VF consistent with APS (2011). HF consistent with Keith et al. (2018)
Final Concentration of CO_2 Product	≥ 98%	Consistent with NASEM (2019)
Cost of Natural Gas [$/MBTU]	3.43	Consistent with NASEM (2019)
Capacity Factor for DAC Plant	90%	Availability from Keith et al. (2018)
Operational Hours [hours/year]	7,884	90%*365*24
Lead Time for DAC Plant [years]	3	
Lead Time factor for DAC Plant cost	1.16	Based on economic lifetime and discount rate

In this analysis, the discount rate reflects the weighted average cost of capital for the construction of the Direct Air Capture (DAC) complex. No terminal or salvage value of equipment at the end of the system's economic lifetime is included. An 8.5% weighted average cost of capital (WACC) has been assumed reflecting recent period values for the firms in the S&P 500.

The annual capital recovery factor in Table S 2 is calculated via the following equation.

$$CRF = \frac{[i(1+i)^n]}{[(1+i)^n-1]}$$

Here, i is the discount rate (between 0 and 1) represented by the WACC and n is economic lifetime in years. For this analysis:

$$CRF = \frac{[0.085(1+0.085)^{20}]}{[(1+0.085)^{20}-1]} = 0.10567$$

From this equation, the capital recovery factor as a fraction of the total capital cost is used to annualize the capital cost based on the plant lifetime and WACC.

3. The Cost of Direct Air Capture

Two scenarios for the capital and energetic requirements of solvent-based DAC were evaluated. The assumptions and modifications to the original analyses to homogenize boundary conditions are outlined in the following sections.

3.1. Horizontal Flow (HF) Case: Derived from *A Process for Capturing CO_2 from the Atmosphere* by Keith et al. (2018)

The costs presented in Keith et al. were modified to be consistent with the analysis presented in the study and represent the lower cost Horizontal Flow (HF) case of the analysis. The capital costs for the process are taken from Table 3 of Keith et al where the core units Total Direct Field Costs (TDFC) are uplifted to a full cost using the ratio of Total Project Cost to TDFC in the table. The core cost used in the present analysis includes the air contactor, pellet reactor, calciner-slaker, ASU, fines filter, other equipment, buildings and transformers. As an objective of the present study was to vary the energy resources used to power the DAC plant, costs for the power plant and steam turbine including an apportioned fraction of the indirect, engineering, contingency, and other project costs, have not been included.

The costs presented in the report include the CAPEX and OPEX for an air separation unit (ASU). The ASU separates oxygen (O_2) from an inlet air stream. This allows the calciner to be fed with pure oxygen, meaning the only products from the combustion will be CO_2 and H_2O, allowing a concentrated CO_2 stream to be recovered. In this analysis, there are multiple energy scenarios that do not require an ASU. Based on the information in the Keith et al. report, the values can be adjusted to represent scenarios with and without the presence of an ASU. To account for the difference between the system with and without the ASU, the total cost of the ASU equipment, including apportioned indirects, etc., is subtracted from the overall CAPEX and OPEX.

Additionally, the capital cost analysis was performed for two different calciner types. Case 1A co-captures CO_2 resulting from natural gas combustion with the CO_2 from the calcination reaction. Therefore, the compressor must be larger for Case 1A to account for increased CO_2 throughput. For all cases presented in this analysis, the CO_2 was assumed to be compressed to 150 bar for transportation (see Section 3.3). As a result, the capital costs are broken down in two tables. Table S 3 shows the cost breakdown for Case 1A and Table S 4 shows the capital cost breakdown for the remaining cases.

Table S 3: HF Case Capital costs for DAC for Case 1A

	Equipment [M$]	**Materials [M$]**	**Labor [M$]**	**Total Direct Field Cost [M$]**
Air Contactor	$114.2	$48	$50	$212.2
Pellet Reactor	$76.9	$28.4	$25.5	$130.7
Calciner-Slaker	$43.8	$18.1	$15.8	$77.7
Air Separation Unit	$38	0	$16.3	$54.3
CO_2 Compressor	$16.0	$1.4	$1.4	$18.43*
Steam Turbine	0	0	0	0
Power Plant	0	0	0	0
Fines Filter	$17.6	$7.1	$6.2	$30.9
Other Equipment	$85.6	$3.0	$2.2	$90.68
Buildings	$2.5		$4.2	$6.7
Transformer		$18.6	$1.2	$19.8
Totals	$394.5	$124.6	$122.8	$641.4
Indirect Field Costs				$81.4
Total Field Costs				$722.7
Engineering				$116.8
Other Project Cost				$44.3
Contingency				$144.6
Total Non-Field Cost				$305.6
Total Project Cost (with ASU)				**$1,028**

Table S 4: HF Case Capital Costs DAC for Case 1B – Case 5

	Equipment [M$]	**Materials [M$]**	**Labor [M$]**	**Total Direct Field Cost [M$]**
Air Contactor	114.2	48	50	212.2
Pellet Reactor	76.9	28.4	25.5	130.7
Calciner-Slaker	43.8	18.1	15.8	77.7
Air Separation Unit	38	0	16.3	54.3
CO_2 Compressor	13.1	1.4	1.4	15.9*
Steam Turbine	0.0	0.0	0.0	0.0
Power Plant	0.0	0.0	0.0	0.0
Fines Filter	17.6	7.1	6.2	30.9
Other Equipment	84.7	3.0	2.2	89.9
Buildings	2.5		4.2	6.7
Transformer		18.6	1.2	19.8
Totals	390.8	124.6	122.8	638.08
Indirect Field Costs				80.9
Total Field Costs				719.0
Engineering				116.2
Other Project Cost				44.1
Contingency				143.8
Total Non-Field Cost				304.0
Total Project Cost (without ASU)				**$936**

Further, the energy requirements for the system can be determined from the original analysis in Keith et al. In Keith et al the natural gas energy values are given as a lower heating value (LHV). To determine the cost of natural gas for the system, they were converted to the higher heating value

(HHV). The energy requirements and total capital costs for the varying cases is shown in Table S 5.

Table S 5: Energy Requirements and Capital Costs for the HF Case

	Electric [GJ/tCO$_2$ from air]	Thermal [GJ/tCO$_2$ from air]	Capital [M$]
Case 1A	1.5	5.8	$1,027
Case 1B – Case 5	0.95	5.8	$936

3.2. Vertical Flow (VF) Case: Modification of *Direct Air Capture of CO_2 with Chemicals* by American Physical Society (APS) (2011)

The costs presented in the APS report were modified to be consistent with the analysis presented in the study and make up the higher cost Vertical Flow (VF) DAC case of the analysis with two main modifications from later work. First, Zeman (2014) states that, as the result of a double count, there was 10% too much thermal energy assigned to the calciner. Adopting this change reduces the thermal requirements from 8 GJ/tCO$_2$ to 7.2 GJ/tCO$_2$. This has a further 10% impact on the electricity requirements of the system via the reduced oxygen requirement from the ASU. Second, Mazzotti et al. (Mazzotti et al. 2013) propose an optimized contactor configuration using a new packing Mellapak-CC. This reduces both the pressure drop over the contactor (and, subsequently, fan power) and the capital cost of the contactors. This results in a 0.10 MWh/t reduction in the fan power.

The APS report additionally assumed that the electricity for the DAC system was provided by the grid and accounts for both the cost and emissions of grid electricity. In the VF DAC system evaluated here, we substituted the energy generating infrastructure outlined in Case 1A through Case 5 in place of the grid.

Similar to the HF case analysis above, only the core DAC units for the process were included. The core units from the APS report are the air contactor, crystallizer, separator-crystal, leacher, separator-leacher, calciner and ASU. A Lang factor of 4.5 was used to multiply the bare major equipment cost to arrive at a fully built-up cost for the system. Additionally, this analysis was carried out for the system with and without the ASU.

Similar to the HF case, two compression configurations must be evaluated to account for increased throughput from the co-capture of CO_2 in Case 1A. For all cases presented in this analysis, the CO_2 was assumed to be compressed to 150 bar for transportation (see Section 3.3). Therefore, the capital costs are broken down in two tables. Table S 6 shows the cost breakdown for Case 1A using the higher cost scenario and
Table S 7 shows the capital cost breakdown for the remaining cases.

Table S 6: VF Case Capital costs for DAC for Case 1A

	APS Report [M$]	Adjusted [M$]	Installed Cost [M$]
Air Contactor	$290	$260	$1,170
Prec, Leacher, Filter	$25	$25	$112.5
Calciner	$120	$120	$540
ASU	$15	$15	$67.5
Compressor	$31	$30	$136.7
Total	**$481**	**$450**	**$2,027**

Table S 7: VF Case Capital Costs for DAC for Case 1B – Case 5

	APS Report [M$]	Adjusted [M$]	Installed Cost [M$]
Air Contactor	$290	$260	$1,170
Prec, Leacher, Filter	$25	$25	$113
Calciner	$120	$120	$540
Compressor	$31	$24	$110
Total	**$466**	**$429**	**$1,933**

Further, the energy requirements for the system can be determined from the original analysis. This includes the modifications from Zeman and Mazzotti et al. The energy requirements and total capital costs for the varying cases is shown in Table S 8.

Table S 8: Energy Requirements and Capital Costs for the VF Case

	Electric [GJ/tCO_2 from air]	Thermal [GJ/tCO_2 from air]	Capital [M$]
Case 1A	1.7	7.2	$2,027
Case 1B – Case 5	1.2	7.2	$1,933

3.3. Compression

The compression energy in this analysis is based on the compression energy in Keith et al., which compresses the resulting high-purity CO_2 stream to 150 bar. Here, the compressor compresses 171 t/h at a CO_2 concentration of 97.12% equivalent to 166 tCO_2/h. This indicates a compressor electricity requirement of 0.13 MWh/tCO_2.

We must note that the size of the compressor varies between the alternative energy cases. In Case 1A, the CO_2 from calciner natural gas combustion is co-mingled with the CO_2 from carbonate decomposition. Case 1A requires a lower bound of 5.52 – 6.84 mmBTU/tCO_2 of thermal energy and the emissions associated with natural gas is 117 lbCO_2/mmBTU (53.2 kgCO_2/mmBTU). This results in 293 – 363 kgCO_2/tCO_2 from calciner natural gas being captured in addition to the 1 $MtCO_2$/year being captured from the plant. This means that the compressor in Case 1A processes 1.29 – 1.36 $MtCO_2$/year whereas Cases 1B thorough 9 process 1 $MtCO_2$/year. Therefore, using the 90% plant capacity factor, Case 1A requires a compressor energy of 21.7 – 22.9 MW while Cases 1B through 9 require a compressor energy of 16.8 MW.

3.4. Technical Readiness Distinctions between the HF and VF DAC Cases

3.4.1. Air Contactor

The most significant design difference between the HF and VF DAC cases is the Air Contactor. In the HF case, based on the publication by Keith et al, the Air Contactor design is based on a cross flow cooling tower. In the VF case based on the APS report, the air contactor is a series of enclosed, counterflow absorption columns/reactors as used in the chemical process industry. Another distinction is the HF case using lower cost PVC plastic based structural packing and the VF case using more costly steel based structural packing.

The cooling tower like Air Contactor in the lower cost case is more open to the environment than the counterflow columns used in the higher cost case. The use of a partially enclosed cross flow contactor using caustic solution to carry out a chemical reaction is novel, and thus lower technology readiness than the Air Contactor in the higher cost case.

In Keith et al, the issue of airborne liquid losses (drift) from the pilot plant air contactor was investigated and results indicated that airborne caustic levels next to the pilot unit were below OSHA acceptable levels (Keith et al. 2018). It is unclear whether this acceptable environmental performance will translate to the open sided cross-flow forced air commercial scale unit described in Keith et al. The reason is that the pilot plant air contactor was of a different design than the commercial unit in the cost analysis. The pilot unit was based on an SPC Marley induced draft cooling tower. In this type of cooling tower, a fan on the top of the unit draws air through the sides which contain the liquid and packing. The air then passes through drift eliminators before entering a central void area below the fan which induced the flow, and the air exits vertically. The propose commercial scale contactor has fans on the side to move the air through the packing and drift eliminators in a straight-line path before exiting horizontally on the opposite side. This design suggests wind born drift losses may be increased versus what was experienced in the pilot unit.

Similarly, the forced air, straight through horizontal path with low pressure drop as described in Keith et al. may have operational challenges. Wind gusts in excess of the fan driven air velocity in the direction of either of the contactor faces could present operational and/or absorber performance problems.

Wind can also cause forced air cooling towers to experience some air recirculation. For DAC, this means wind can result in some air with already depleted CO_2 re-entering the contactor, lowering capture quantities.

The open design of the forced air contactor introduces other potential issues which contribute to a low TRL. Some of these issues were raised in Chapter 6 of the book "Geo-Engineering Climate Change: Environmental Necessity or Pandora's Box?" (Launder and Thompson 2010):

- Freezing temperatures can result in icing problems at the air intake and/or solidification of the liquid sorbent and possible precipitation of caustic.
- Particles in the air may enter the absorber which may need to be filtered. In addition, these solids may dissolve in the caustic solution or react to form films/foam, leading to operational problems.

These factors contribute to technical and operational uncertainty for the Air Contactor in the HF case.

3.4.2. Fluid Bed Calciner

The second major innovation in the HF case versus the VF case is the use of a fluid bed calciner to convert the small spherical pellets of $CaCO_3$ formed in the pellet reactor to CaO. The VF case utilizes a kiln calciner similar to that used in the paper/pulp industry. Below are some traits of fluid bed reactions which could lead to possible operability issues suggesting a lower technology readiness level (TRL) with the HF case fluid bed calciner.

- **Attrition Losses** – in the fluid bed, ceramic-like and softer particles will both crack open and also attrite away the surface by grinding on each other. The very fine particles formed present both a potential source of physical losses and handling challenges.
- **Incomplete reaction** – A trade off in the choice of using a fluid bed versus a fixed bed configuration for chemical reactions is the relative importance of temperature control/heat

management (better in fluid bed) versus obtaining complete reaction/conversion of the feedstock (easier to manage in a fixed bed). In a fluid bed because of the back mixing of already reacted gas with the incoming natural gas and oxygen, it is possible some natural gas will also be in the effluent of a commercial scale fluid bed reactor along with the CO_2 and water vapor. A small amount of methane in the product CO_2, may or may not be an issue. Natural gas in the effluent can be minimized by increasing the surplus oxygen, but oxygen breakthrough with the CO_2 will increase.

- **Could a fluid bed calciner use electric resistance heating?** With electric heating recycle CO_2 or steam would likely be used as the fluidizing medium. Since the decomposition to CaO is endothermic and equilibrium limited, if CO_2 is used as a fluidizing medium, increasing the partial pressure of CO_2 is likely to increase calciner energy requirements. Alternatively, using steam may present some challenges recovering the CaO.

In summary, while the HF DAC case is economically attractive, the presence of lower TRL unit operations increases the possibility of operability issues resulting in decreased annual CO_2 capture and increasing costs relative to the higher TRL unit operations in the VF DAC case.

3.5. Lang Factor Analysis

In the present work, a factor of 4.5 was used to arrive at the full cost for the VF DAC case. In Keith et al., a Lang factor is not used, but a full project cost was built up from the major equipment using estimates of indirect costs and contingencies. A proxy Lang Factor can be back calculated from the data presented in Keith et al (Table 3). Here, the total major equipment cost is M$347, which corresponds to the bare equipment cost of the air contactor, pellet reactor, calciner-slaker, ASU, compressor, steam turbine, power plant, and fines filter. The total project cost is M$1,127. These values back calculate to a Lang Factor of 3.2. If we take this same logic and apply it to the cost values in Table S 3 and Table S 4 the implicit Lang factors are ~3.5.

4. EIA 2020 *Annual Energy Outlook* Data

The capital and operating expenses for five of the energy resource types considered in this analysis were obtained from the EIA Cost and Performance Characteristics of New Generating Technologies in the *Annual Energy Outlook* 2020 (U.S. Energy Information Administration (EIA) 2020). These energy types include wind, advanced NGCC, NGCC with CCS, advanced nuclear, geothermal and solar energy. Additional information presented here includes CAPEX and OPEX information related to battery storage (Fu, Feldman, and Margolis 2018). This information is outlined in Table S 9 below.

Table S 9: Unscaled CAPEX and OPEX parameters for wind, advanced NGCC, NGCC with CCS, advanced nuclear, solar energy and battery storage from the EIA Annual Energy Outlook (2020) and small modular nuclear energy from Black et al. (2019)

	Wind	**NGCC w/ CCS**	**Advanced Nuclear**	**Small Modular Nuclear**	**Solar**	**Geothermal**	**Battery Storage**
Overnight Cost [$/kW]	$1,319	$2,569	$6,317	$3,605	$1,331	$2,680	$1,383
Plant Size [MW]	200	377	2,156	685	150	50	50
Base Plant Cost [M$]	163.8	968.5	13,619.5	2,469	199.7	134.0	69.2
Battery Capacity [MWh]	-	-	-		-	-	200
Lead Time [Years]	3	3	6	5	2	4	1
Final Heat Rate [BTU/kWh]	-	7493	10461	-	-	-	-
Variable O&M [$/MWh]	$0.00	$5.82	$2.36	$2.36*	$0.00	$1.16	$0.00
Fixed O&M [$/kW/year]	$26.22	$27.48	$121.13	$121.13*	$15.19	$113.29	$24.70
Base Plant Annual Fixed O&M [$M]	$5.24	$10.36	$261.16	$261.16*	$2.28	$5.66	$1.24
Efficiency (Thermal or Round Trip)	-	46%	33%	-	-	-	85%

*Assumed the same as Advanced Nuclear

An in-depth outline of each energy system evaluated in the EIA is provided in the *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies* (U.S Energy Information Administration (EIA) 2020). Brief descriptions of each technology, from the referenced report (U.S Energy Information Administration (EIA) 2020) and consistent with the data provided in Table S 9, are provided in the following paragraphs.

Solar Photovoltaic (PV) This case details a nominal 150 MW_{AC} solar PV facility with single-axis tracking, using 195 MW_{DC} of 1,500-V monocrystalline PERC modules with independent row trackers. The system is composed of 487,500 individual 400-watt, 1500-V monocrystalline solar modules with PERC architecture. The modules are connected in series to one another. The

strings are each composed of 30 modules and connect to each other in parallel to form large solar arrays. The solar arrays make up the bulk of the facility.

Onshore Wind This Great Plains region onshore wind project is based on a 200 MW total project capacity. The turbine nameplate capacity, rotor diameter, and hub height can affect project cost and performance, among other parameters. This onshore wind configuration assumes 71 wind turbines with a nominal rating of 2.8 MW, a 125-meter rotor diameter, and a 90 m hub height.

Nuclear PWR This case is a pressurized water reactor nuclear plant designed by Westinghouse (AP1000 – where AP stands for 'Advanced Passive'). This has been designed to include fewer components (i.e. wiring, piping, valves). This system uses a traditional steam cycle, similar to combined cycle unit, for a capacity of 2,156 MW. Each generator is a 60-Hz machine rated at approximately 1,250 MW on average with an output voltage of 24 kV.

Geothermal The EIA geothermal system has a 50 MW base plant size and uses a binary cycle. The use of a binary cycle rather than flash would typically be considered for geothermal production temperatures of 350°F or less; this system assumes a 300ºF geothermal reservoir temperature. One geothermal production well typically has the potential to convert the well's thermal power into ~3 MW of electric power. This has 17 production wells and 10 injections wells, between the typical range of a 2:1 to 1:1 ratio of production wells to injection wells.

Capacity Factors

The capacity factors of the DAC complex will be impacted by the energy resource used. For dispatchable power, NGCC with CCS, geothermal and nuclear, a net 90% capacity factor results from the assumption used for the DAC section. For intermittent sources, to achieve the 90% capacity factor for the DAC complex, battery storage is included. This battery storage is based on the daily capacity factor, reflective of the daily availability of intermittent energy resources. The battery storage requirement is determined by the use of a best-in-class daily capacity factor for solar (35.2%) and wind (52%) given the flexibility in placement of DAC plants (NREL 2019). The different energy source scenarios do not consider/include the potential impact of unanticipated outages, for example periods of cloud cover or still winds.

5. Scaling Process Equipment

The cost data provided by the EIA, as well as the cost data provided for the additional process equipment must be scaled from the original reference plant size to fit the energy needs of the DAC plant. To do this, the following scaling relationship is used.

$$\text{New Cost} = \text{Base Cost}^{*} \left(\frac{\text{New Plant Size}}{\text{Base Plant Size}}\right)^{\alpha}$$

Here, the base cost is the reference cost (in either dollars or $/kW), the base plant size is the base production of the plant that corresponds to the base cost, the new plant size is the requirements to power the DAC plant, and α is a scaling factor. The scaling factors used in this analysis are presented in Table S 10. The base and new plant size units depend on what plant type is being scaled. For example, the solar energy alternatives will be scaled based on the MW capacities for the plant.

Table S 10: Equipment Scaling Factors

Process Type	Scaling Factor (α)
Natural Gas Power	0.7
Solar Power	0.95
Utility Scale Battery Storage	0.95
Nuclear (Large Pressurized Water Reactor)	0.6
Nuclear (Small Modular Nuclear Reactors)	0.7
Wind Energy	0.95
Geothermal	0.95

6. Seasonality of Solar Electricity

The fuel and/or power consumed by a complex capturing CO_2 from the air utilizing a high temperature calciner will desire continuous 24/7 operation due to long start-up ramps. If this continuous operation is an imperative, then using an intermittent energy source like solar power presents a challenge to continuous operation of the air capture plant. However, combining solar power generation with battery storage should enable continuous operation.

Given the air capture complex energy requirement, the daily capacity factor for the solar power generation will determine the nameplate solar capacity needed and the amount of battery storage. The NASEM report included an example with a best-in-class solar average daily capacity factor of 35.2% (Bolinger and Seel 2018). This percentage is equivalent to an average of 8.45 peak sun hours per day. Therefore, batteries need to supply the air capture complex an equivalent of 15.55 hours a day. A hypothetical case assuming these percentages can be constructed and represents a good proxy for a plant located near the equator.

Assuming a Northern Hemisphere location, in a practical sense the continuous operation imperative for the air capture complex would require the solar electricity power block to be sized large enough to provide enough energy to power the complex around the winter solstice. As an illustration, assume the solar power block with the 35.2% average capacity factor was in sunny South-Central Arizona (e.g. near Phoenix). The daily average incident radiation would be ~8.97 kWh per square meter per day. However, the seasonal low point is only 6.14 kWh per square meter per day, dropping the effective daily capacity factor from the annual average of 35.2% to 24.1% around the winter solstice (Honsberg and Bowden 2017). If the solar power block is sized based on the lower winter solstice daily capacity, it will produce excess electricity over and above that needed for the air capture complex nearly every day of the year outside of the annual low point.

In this analysis two different daily capacity factors are used to size the solar power generation and battery storage capacity: a daily capacity factor in the NASEM report that does not account for the seasonal availability of solar electricity to construct a near the equator proxy case (35.2%) and using a seasonal low adjusted daily capacity factor (24.1%) based on the NASEM case (U.S. Energy Information Administration (EIA) 2020; Bolinger and Seel 2018; Honsberg and Bowden 2017). This more practical example for a US location could export surplus solar electricity most of the year. These cases are used in the analysis for alternatives using solar electricity sources.

It is important to note that these cases illustrate the high impact of seasonality and illustrate that solar based DAC complexes are probably best placed near the equator to minimize seasonality impacts and lower capital cost.

7. Direct Emissions from Energy Usage

With each type of energy resource, there are emissions associated with the production and usage of these resources. The emissions for energy resources related to electricity production are shown in Table S 11.

Table S 11: Emissions Intensities by Electricity Source

Energy Resource	Emissions Intensity	Source/Notes
Wind	0	(U.S. Energy Information Administration (EIA) 2020)
Advanced NGCC	344 gCO_2/kWh[a]	(U.S. Energy Information Administration (EIA) 2020)
NGCC with CCS	38 gCO_2/kWh[a]	(U.S. Energy Information Administration (EIA) 2020) Assuming 90% Capture
Advanced Nuclear	0	(U.S. Energy Information Administration (EIA) 2020)
Solar	0	(U.S. Energy Information Administration (EIA) 2020)
Geothermal	26 gCO_2/kWh	(U.S. Energy Information Administration (EIA) 2016; U.S. Department of Energy (DOE) n.d.) Average for all generation, varies by region

[a] This value is calculated using the heat rate for the NGCC presented in Table S 9 using the following equation.

$$\text{Emissions}\left[\frac{gCO_2}{kWh}\right]=\text{Final Heat Rate}\left[6370\ \frac{BTU}{kWh}\right]*\frac{MBTU}{10^6 BTU}*\text{Emissions}\left[119\ \frac{lbCO_2}{MBTU}\right]*454\left[\frac{gCO_2}{lbCO_2}\right]$$

[b] This value is calculated using the heat rate for the NGCC with CCS presented in Table S 9 using the following equation. Here, 90% CO_2 capture is assumed.

$$\text{Emissions}\left[\frac{gCO_2}{kWh}\right]=\text{Final Heat Rate}\left[7124\ \frac{BTU}{kWh}\right]*\frac{MBTU}{10^6\ BTU}*\text{Emissions}\left[119\ \frac{lbCO_2}{MBTU}\right]*454\left[\frac{gCO_2}{lbCO_2}\right]*0.1$$

8. Embodied Emissions

The embodied emissions estimates used for each process operation are outlined in the following sections. Results from the embodied emissions analysis for each alternative case is presented in Section 16.

8.1. Power Section

8.1.1. Embodied Emissions of Energy Production and Batteries

The embodied emissions for energy resources and lithium ion storage batteries are taken from *Renewable Electricity Futures Study* values from Volume 1, Table C-1 of the study (National Renewable Energy Laboratory (NREL) 2012) and presented in Table S 12. These emissions are reported in one-time upstream emissions indicating emissions that result as a part of the construction process before the energy resource is utilized. Ongoing non-combustion emissions refer to emissions that are continuous but are not related to the combustion of fossil or other fuel sources. One-time downstream emissions include system retirement and emission occurring after the system is decommissioned.

Table S 12: Embodied emissions rates for varying energy resources and lithium ion batteries.

Technology	**One-Time Upstream Emissions [tCO_{2e}/MW]**	**Ongoing Non-Combustion Emissions [$kgCO_{2e}$/MWh]**	**One-Time Downstream Emissions [tCO_{2e}/MW]**
Nuclear (National Renewable Energy Laboratory (NREL) 2012)	350	10.6	175
Geothermal (National Renewable Energy Laboratory (NREL) 2012)	836	9.7	0
PV Solar (National Renewable Energy Laboratory (NREL) 2012)	1630	0	37.8
Onshore Wind (National Renewable Energy Laboratory (NREL) 2012)	619	1.41	22.4
Nat Gas Combined Cycle (NGCC) with CCS (National Renewable Energy Laboratory (NREL) 2012; O'Donoughue et al. 2014)	180	9	6.3
	[tCO_{2e}/MWh]	**[$kgCO_{2e}$/MWh]**	**[tCO_{2e}/MWh]**
Li Ion Storage Batteries. (Romare and Dahllöf 2017)	190	0	15

To calculate the embodied emissions associated with NGCC with CCS, the baseline embodied emissions of natural gas were used as previously described (National Renewable Energy Laboratory (NREL) 2012), however the emissions were adjusted using O'Donoughue et al. (2014). Here, the ratio of the median values for both NGCC and NGCC with CCS from O'Donoughue et al. were used to develop one-time values for NGCC with CCS based on the embodied emissions for NGCC in the *Renewable Electricity Futures Study*. For these cases the one-time GHG

emissions associated with plant construction and where available the one-time GHG emissions associated with plant decommissioning were applied evenly over the 20-year economic plant life.

8.2. Natural Gas

An analysis by Alvarez et al was used to determine the supply chain emissions from natural gas (Alvarez et al. 2018). In addition to a relatively small amount of CO_2 generated from the energy used for production and distribution, the bulk of embodied emissions result from upstream methane leakage. The authors arrive at 2.3% loss of natural gas production in the supply chain assuming that 90% of natural gas is methane. Information regarding these emissions that were used in this analysis are presented in Table S 13, with the exception that only emissions up to and including primary distribution were included, i.e. the local distribution and oil refining/transportation values were not included for the DAC case analysis.

Table S 13: 2015 Methane emissions from the Natural Gas Supply Chain (Data from (Alvarez et al. 2018))

Stage	Methane [Tg/year]
Production	7.6
Gathering	2.6
Processing	0.72
Trans/Storage	1.8
Local Distribution	0.44
Oil Refining/Trans	0.034
Total	13.194

To calculate the impact of these emissions on a per tonne CO_{2e} basis the GWP20 of 86 was used and a GWP100 of 32 was used. Using this information, the upstream emissions resulting solely from upstream methane leakage are 0.036 tCO_{2e}/GJ for GWP20 and 0.013 tCO2e/GJ for GWP100. When including supply chain CO_2 leakage, these numbers come out to 0.041 tCO_{2e}/GJ for GWP20 and 0.018 tCO_{2e}/GJ for GWP100. These values were used to determine the embodied emissions for alternatives using natural gas.

8.3. Direct Air Capture Section

The embodied emissions associated with solvent-based DAC can only be roughly approximated as integrated demonstration or industrial-scale DAC facilities have yet to be built. To approximate the one-time embodied GHG emissions from DAC plant construction, the values estimated for an SMR plant were based on data from *Critical Materials Requirements for Petroleum Refining* for the metal material requirements (Wells 1966), the ICE Database V3.0 (Circular Ecology 2019) for the embodied emissions within the metal materials, and Olivetti et al (2013) to determine the embodied emissions of motors, and Wei et al (2017) for the transformers. These estimates were multiplied by the ratio of the capital costs of the VF and HF DAC plants relative to the SMR plant to determine the embodied emissions of the DAC facility. This analysis assumed that capital cost was directly proportional to the embodied emissions of the system. This was repeated for the cases with and without the ASU, as well as for the varying compression capital costs between Case 1A and the other cases. The relationship used is illustrated below:

$$\text{Embodied Emissions } [tCO_2] = \frac{\text{DAC CAPEX [M\$]}}{\text{SMR CAPEX [M\$]}} * \text{SMR Embodied Emissions}[tCO_2]$$

The embodied emissions for the DAC facility are approximations developed by adjusting the calculated embodied emissions associated with a large chemical processing unit operation with known materials of construction, in this case a refinery steam-methane reformer (SMR), by using the capital cost ratios to estimate the embodied emissions of the DAC facility (see Supporting Information Section 8.3 and Methods section). For example, the SMR facility producing 205,000 kg H_2/day uses 845 tonnes of carbon steel (Wells 1966). Using a coefficient of 1.7 kg CO_2/kg carbon steel results in 1,436 tCO_2/facility (Circular Ecology 2019). The SMR facility has a capital cost of $278 million (Gandrik et al. 2010) and the emissions are scaled to the capital cost of the lower cost case ($1,023 million) to give a DAC facility embodied carbon steel emissions of 0.00026 tCO_2/tCO_2 from air over the system lifetime (20 million tCO_2 capture). Including all embodied emissions for SMR the HF DAC facility has embodied emissions of between 0.00088 tCO_2/tCO_2 (electric kiln) and 0.00096 tCO_2/tCO_2 (natural gas kiln) and the VF DAC facility has embodied emissions of 0.0021 tCO_2/tCO_2 for both the electric kiln and natural gas kiln.

While this approach results in consistent DAC facility embodied emissions across all the alternatives presented here, it is only an approximation and, may not correspond directly to the embodied emissions of DAC facility. As the impacts of the calculated embodied emissions for the DAC facilities are small, significant errors in the embodied emissions estimate for the DAC facility would not materially impact the calculated cost of the net CO_2 captured. For reference, similar analysis on using DAC for Fischer-Tropsch fuel production estimated the embodied emission for DAC as 0.04 tCO_2/tCO_2 using a non-fossil energy resource and 0.14 tCO_2/tCO_2 when using a fossil-based energy resource. The authors similarly used a SMR facility as a proxy (Liu et al. 2020). However, additional research into the embodied emissions associated with DAC is desired. The complete results from the embodied emissions analysis are presented in Section 17.

9. Incremental Cost of Flue Gas CO_2 Capture from a NGCC Using the EIA Data

The incremental cost of carbon capture of 90% of the CO_2 emissions from natural gas combustion flue gas on a NGCC was calculated using the EIA *Annual Energy Outlook* data (U.S. Energy Information Administration (EIA) 2020). The data from the EIA report used to calculate the incremental CCS cost is shown in Table S14.

Table S14: EIA Data Used to Calculation the Incremental Cost of Carbon Capture and Storage from a NGCC Power Plant (U.S. Energy Information Administration (EIA) 2020)

	Advanced NGCC	**Advanced NGCC with CCS**	**Difference***
Size [MW]	1083	377	
Lead Time [Years]	3	3	
Base Overnight Cost [$/kW]	$954	$2,470	$1,516
Technical Optimization Factor	1	1.04	
Total Overnight Capital Cost [$/kW]	$954	$2,569	$1,615
Variable O&M [$/MWh]	$1.86	$5.82	$3.96
Fixed O&M [$/kW/yr]	$12.15	$27.48	$15.33
Final Heat Rate [BTU/kWh]	6370	7124	754
Base CO_2 Emissions [lbs/mmBTU]	117	117	

* The difference is calculated based on the NGCC subtracted from the NGCC with CCS (i.e. Difference = Advanced NGCC – NGCC)

The incremental cost of CCS for this system is divided into four main parts: the capital cost, the fixed operating and maintenance costs, the variable operating and maintenance costs, and the natural gas costs. Each of these costs will be summed to determine the overall incremental cost of CCS for the NGCC system on a per tonne CO_2 captured basis.

This calculation serves as a baseline comparison for the applicability of the EIA data used here to develop the capture cost values from air. The cost of flue gas capture was calculated at \$85/tCO_2 using the economic assumptions of this work with the EIA data. For comparison, costs have been reported from \$58 – 138/tCO_2 avoided for post-combustion NGCC carbon capture (Rubin, Davison, and Herzog 2015; Irlam 2017). The details of this calculation are provided in the Supporting Information Section 9.

For perspective, the cost of CO_2 capture from air using the HF DAC case with natural gas energy of \$230/tCO_{2e} is nearly 2.5 the cost estimate of the point source capture. In contrast, the concentration difference between the air (~400 ppm CO_2) is 100 times more dilute than flue gas from a NGCC plant (4-5% CO_2).

The complete calculation for the incremental cost of capture is presented in **Appendix A**.

10. Case 1A: Natural Gas with Combustion Calciner

This scenario represents a base case that aligns with the natural gas alternative presented in the Solvent section of Chapter 5 of the NASEM 2019 report (National Academy of Sciences Engineering and Medicine 2019). The major underlying assumptions for this case are outlined here:

- Natural gas provides all of the thermal energy for the system. The natural gas is combusted inside the calciner allowing for co-capture with the resulting CO_2 stream.
- Natural-gas derived electricity with carbon capture (NGCC-CCS) provides all of the electricity requirements for the system. Approximately 90% of natural gas electricity emissions are captured by a flue gas capture unit.
- An ASU is required for feeding pure oxygen to the natural gas Calciner (oxy-fired), with natural gas-produced CO_2 recovered with the air captured CO_2.
- A scaling factor of 0.7 is used to scale the plant size from the original EIA data to the desired size for this analysis.
- The NGCC power plant has a lead time of 3 years, corresponding to a lead time cost factor of 1.16.

A representative process flow diagram of this system is shown in Figure S 1.

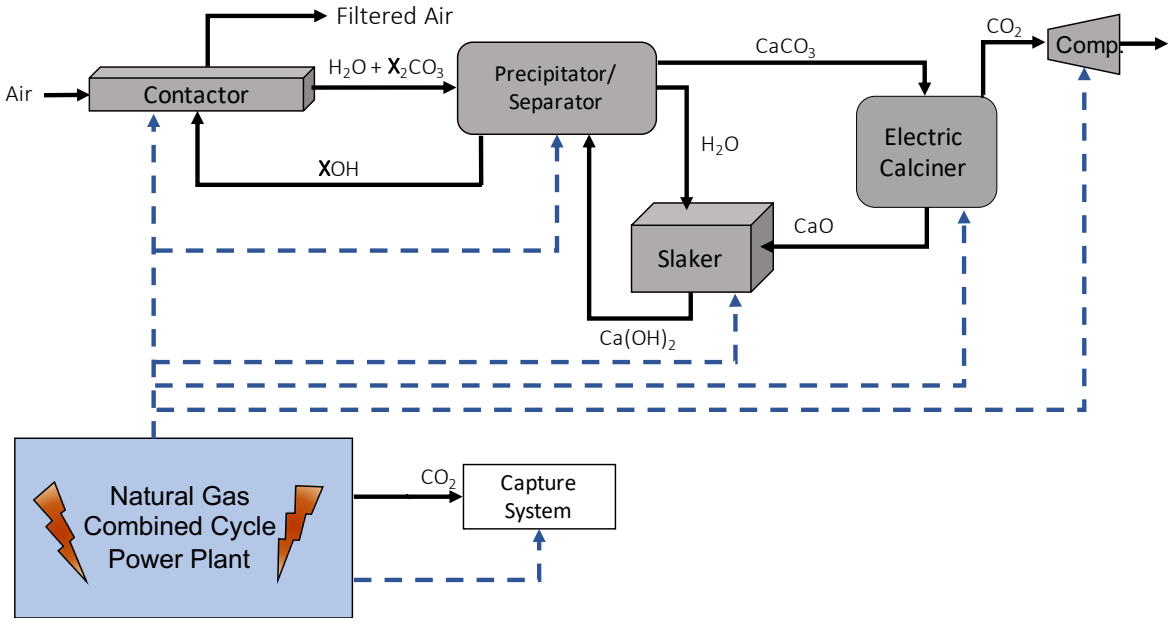

Figure S 1: Representative process diagram for the base case involving natural gas Calciner with an air separation unit and oxy-fired calciner (Case 1A). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used. The black arrows represent material flows. The dashed blue arrows represent electricity flows and the dashed red arrows represent thermal energy flows. The natural gas arrow is black with a dashed red arrow as well. This is meant to indicate the physical flow of natural gas into the reactor, which is also providing the thermal energy.

11. Case 1B: Electric Resistance Calciner Powered by Natural Gas Combined Cycle with Carbon Capture (NGCC- CCS) Electricity Production

This case explores the use of an electrical resistance Calciner for calcination, with the same efficiency assumption as a natural gas Calciner. Here, all of the system components are powered by electricity from a natural gas combined cycle with carbon capture (NGCC-CCS) facility. Major assumptions associated with this scenario are outlined below:

- Natural-gas derived electricity with carbon capture provides all of the electricity requirements for the system. Approximately 90% of natural gas electricity emissions are captured by a flue gas capture unit. Since the calciner in this scenario uses electricity, the only energy requirements to the DAC system are electricity.
- Capital and operating expenses for both the NGCC plant is consistent with those outlined in Table S 9.
- A scaling factor of 0.7 is used to scale the plant size from the original EIA data to the desired size for this analysis.
- The NGCC power plant has a lead time of 3 years, corresponding to a lead time cost factor of 1.16.

A representative process flow diagram of this system is shown in **Figure S 2**.

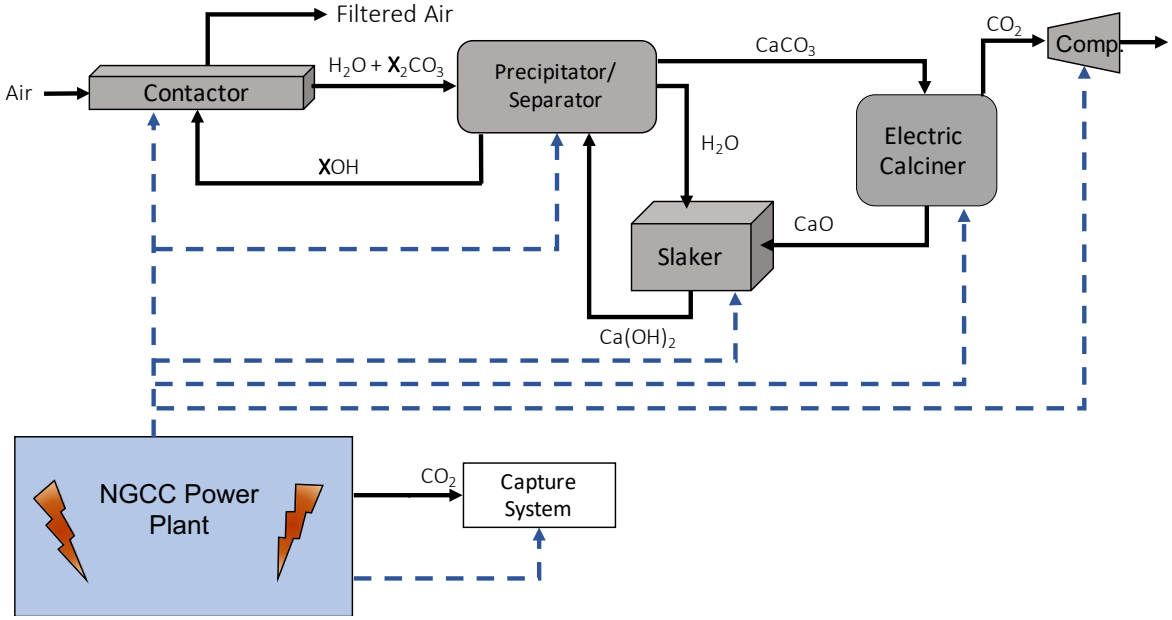

Figure S 2: Representative process diagram for the case involving an electrical resistance Calciner powered by NGCC electricity (Case 1B). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used.

12. Case 2: Electric Resistance Calciner Powered by Solar Electricity

This case explores the use of an electrical resistance Calciner for calcination, with the same efficiency assumption as a natural gas Calciner. Here, all of the system components are powered by electricity from a solar generating facility. To account for off-generating hours, batteries are sized to store excess solar electricity during generating hours to ensure continuous operation. Major assumptions associated with this scenario are outlined below:

- Photovoltaic (PV) solar-derived energy fulfills all electrical and thermal energy needs for the system.
- Lithium-ion battery storage and inverter are necessary for storing solar energy to keep the system continuously operating during off-generating hours.
- Capital and operating expenses for both the solar energy plant and the battery storage are consistent with those outlined in Table S 9.
- A scaling factor of 0.95 was used to scale the solar plant size from the original EIA data to the desired size for this analysis.
- A scaling factor of 0.95 was used to scale the battery storage size from the original EIA data to the desired size for this analysis.
- A round trip efficiency of 85% is used to account for losses associated with battery storage (Fu, Feldman, and Margolis 2018). These losses include losses within the battery itself and the energy necessary to maintain the climate control in the utility scale battery modules.
- The solar power plant construction has a lead time of 2 years, corresponding to a lead time cost factor of 1.13.

Additionally, a representative diagram of Case 2A and 2B is outlined in Figure S 3.

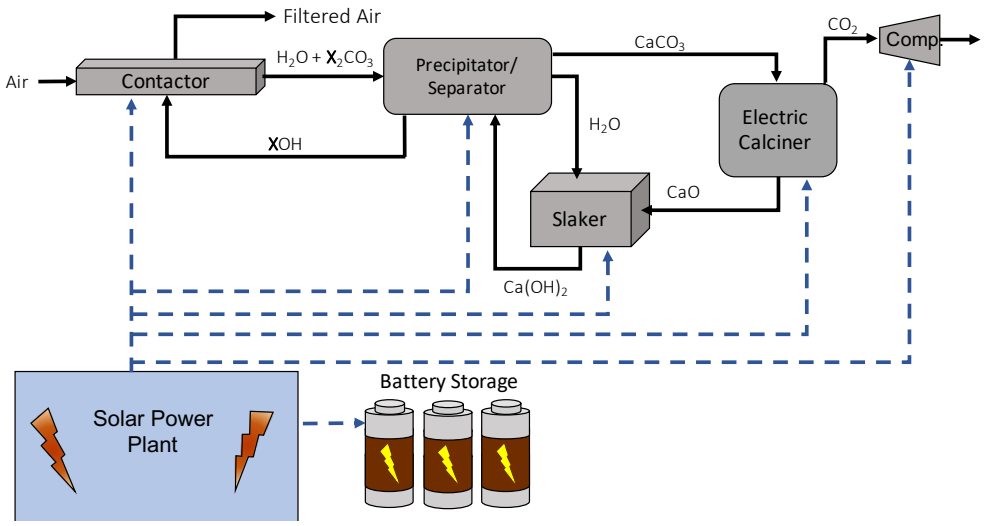

Figure S 3: Representative process diagram for the case involving an electrical resistance Calciner powered by solar electricity (Case 2A and 2B). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used.

This case can be further divided into two cases: (A) a hypothetical case with a best-in-class average annual daily capacity factor with no adjustment for solar seasonality, (B) the high daily capacity factor case that has been adjusted to size the power capacity to allow continuous DAC plant operation around the winter solstice.

12.1. Case 2A: Best-in-class Annual Average (No Seasonality)

The daily capacity factor of this system is 35.2% as used in the NASEM report (Bolinger and Seel 2018; National Academies of Sciences Engineering and Medicine (NASEM) 2019) and developed in above Section 5. This case is hypothetical in that most days the solar and battery complex is either under sized or oversized relative to the demand of the DAC section. Placing the plant near the equator would minimize these deviations.

12.2. Case 2B: Adjusted for Solar Seasonality

The analysis in this case adjusts the solar capacity required to account for seasonality in the availability of solar electricity by sizing the solar and battery complex large enough to be able to operate the DAC complex during the winter solstice in central Arizona. An adjusted daily capacity factor for solar of 24.1% (Honsberg and Bowden 2017) is used to size the complex to fit the output around the winter solstice, as developed in above Section 5. Here, the excess energy is sold to the commercial grid at a rate of $60/MWh.

13. Case 3: Electric Calciner Powered by Wind Electricity

The third case presented involves the complex powered by wind electricity. To account for off-generating hours, batteries are sized to store excess solar electricity during generating hours to ensure continuous operation. Major assumptions associated with this scenario are outlined below:

- Wind-derived energy fulfills all electrical and thermal energy needs for the system.
- The daily capacity factor for wind power generation is a best-in-class 52% (NREL 2019).
- Lithium-ion battery storage is necessary for storing wind energy produced during generating hours to keep the DAC system continuously operating during non-generating hours.
- A scaling factor of 0.95 was used to scale the wind plant size from the original EIA data to the desired size for this analysis (see methodology in Section 5).
- A scaling factor of 0.95 was used to scale the battery storage size from the original EIA data to the desired size for this analysis.
- As in Case 2, round trip efficiency of 85% is used to account for losses associated with battery storage (Fu, Feldman, and Margolis 2018).
- The wind power plant has a lead time of 3 years, corresponding to a lead time cost factor of 1.16.
- As with solar, a best-in-class average daily capacity factor was used, which for wind is 52% (NREL 2019). Battery storage is used to allow the DAC complex to run continuously. As with solar, expected but unpredictable outages from, in this case, still periods, are not included.

Additionally, a representative diagram of Case 3 is outlined in Figure S 4.

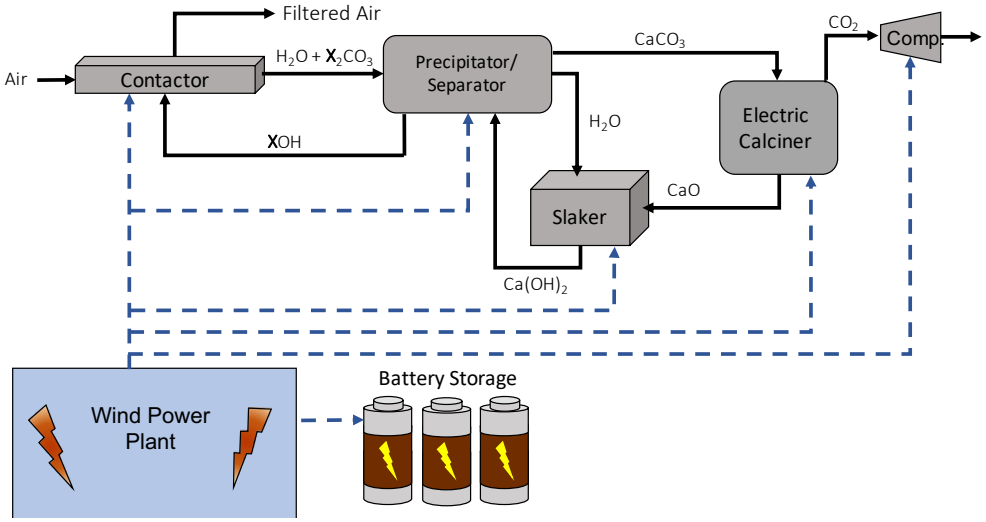

Figure S 4: Representative diagram for the case involving electrical resistance Calciner powered by wind electricity (Case 3). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used.

14. Case 4: Electric Calciner Powered by Nuclear Electricity

The fourth case in this analysis has all system components powered by nuclear electricity, including the Calciner. Since nuclear energy has a large on-line factor to meet the DAC energy requirements, no battery storage is needed in this scenario.

A representative diagram of Case 4 is outlined in Figure S 5.

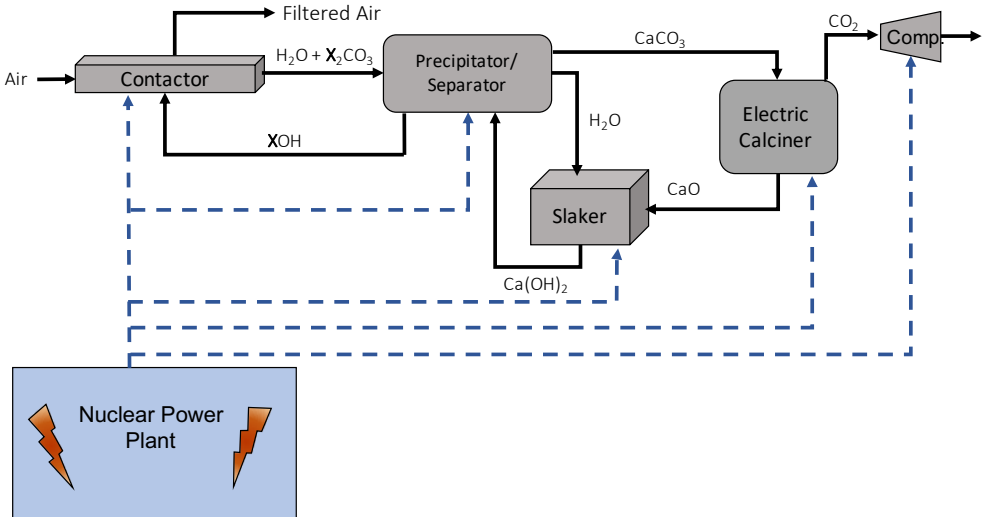

Figure S 5: Representative diagram for the case involving electrical resistance Calciner powered by nuclear electricity (Case 4). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used.

Additionally, this case is divided into two scenarios: (A) a scaled pressurized water rector (PWR) nuclear power plant based on data presented in the EIA report (U.S. Energy Information Administration (EIA) 2020) and (B) an alternative scenario that uses a cluster of small modular nuclear reactors to meet electricity and thermal energy requirements.

14.1. Case 4A: PWR Nuclear Power Scaled from EIA data

This analysis uses the nuclear capital and operating costs as outlined in the EIA report and shown in Table S 9. The nuclear power plant has a lead time of 6 years, corresponding to a lead time cost factor of 1.33. For this analysis the number of DAC plants are scaled to meet the base plant size presented in the EIA report (on account of the poor down scaling capabilities of PWR Nuclear facilities. A scale power factor of 0.6 would be needed which leads to very high capital cost per MW at small plant sizes). No scaling factor was used for the DAC facilities, although an alternative discussion in the text suggests an 0.85 scaling factor could appropriately represent the cost-savings associated with co-constructing multiple DAC facilities. Ultimately, this was analogous to 9, 1 MCO_2/year DAC facilities for the HF DAC scenario and 7, 1 $MtCO_2$/year DAC facilities for the VF DAC scenario.

14.2. Case 4B: Nuclear Energy from Small Modular Nuclear Reactors

This analysis uses the nuclear capital cost for a cluster of 12, 60Mwe gross power output NuScale l modular nuclear reactors resulting in a 685 MW net power output after accounting for electric consumption of the nuclear plant cluster as outlined in Black et al. (2019) The small modular

nuclear reactors allow smaller plants to be built compared to conventional nuclear reactors which average ~3.5 GW in size (Sandalow et al. 2018). Smaller power plants are better suited to power individual DAC facilities. The cost values for the small nuclear reactors in this analysis are scaled from the base 685 MW using a 0.7 exponential scaling factor assumption reflective of the modular design. The data for the capital cost of the small modular nuclear reactors is shown below in Table S 9. The nuclear power plant has a lead time of 5 years, corresponding to a lead time cost factor of 1.27.

Since operational information for these small modular nuclear reactors is not widely available (due to the novelty of the technology), the EIA data for advanced nuclear operating costs has been used in this analysis. Literature on these reactors indicates that they have the potential to reduce replacement power costs, however, they also indicate that the price of fuel inputs may be greater (Lokhov, Sozoniuk, and Rothwell 2016). Additionally, NuScale states a lower operating cost than conventional nuclear power generation (NuScale 2019).

15. Case 5: Electric Resistance Calciner Powered by Geothermal Electricity

This case explores the use of an electrical resistance calciner for calcination, with the same efficiency as a natural gas calciner. Here, all of the system components are powered by electricity from a geothermal generating facility. Major assumptions associated with this scenario are outlined below:

- Geothermal-derived energy fulfills all electrical and thermal energy needs for the system.
- Capital and operating expenses for the geothermal energy plant is consistent with Table S 9.
- A scaling factor assumption of 0.95 was used to scale the geothermal plant size from the original EIA data to the desired size for this analysis.
- The solar power plant has a lead time of 4 years, corresponding to a lead time cost factor of 1.21.

Additionally, a representative diagram of Case 5 is outlined in Figure S 6.

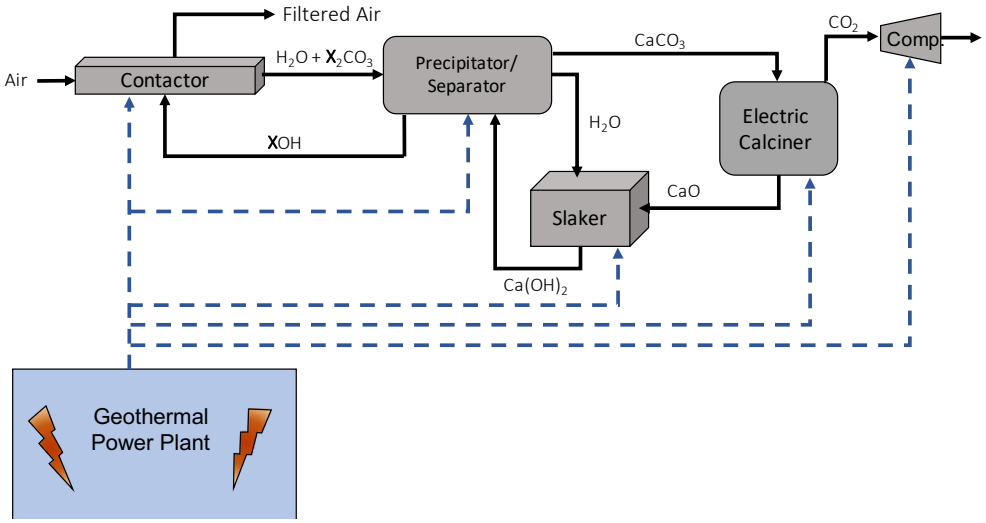

Figure S 6: Representative diagram for the case involving electrical resistance calciner powered by geothermal electricity (Case 5). Here, **X** represented sodium (Na) or potassium (K) depending on the solvent used.

16. Methane Supply Chain Leakage

The complete tabulation of the take-back parameters for each net removed cost presented in Table 1 in the main text are outlined in Table S 15.

Table S 15: Cost multiplier, net removed costs for emissions resulting directly from energy generation and from upstream methane leakage.

	Methane Leakage Rate	Alt	GWP	Direct Emissions [tCO_2/tCO_2]	Methane Leakage [tCO_{2e}/tCO_2]	x [tCO_{2e}/tCO_2]	Cost Mult $\left[\frac{1}{1-x}\right]$	Net Removed Cost [$/$tCO_2$]
Case 1A Natural Gas Thermal	0.2%	HF	GWP 20	0.014	0.027	0.041	1.0	230
			GWP 100	0.014	0.010	0.024	1.0	230
		VF	GWP 20	0.017	0.032	0.049	1.1	420
			GWP 100	0.017	0.012	0.029	1.0	410
	2.3%	HF	GWP 20	0.014	0.31	0.32	1.5	330
			GWP 100	0.014	0.11	0.13	1.1	260
		VF	GWP 20	0.017	0.37	0.39	1.6	650
			GWP 100	0.017	0.14	0.16	1.2	470
	3.7%	HF	GWP 20	0.014	0.49	0.51	2.0	450
			GWP 100	0.014	0.18	0.20	1.2	280
		VF	GWP 20	0.017	0.60	0.62	2.6	1,030
			GWP 100	0.017	0.22	0.24	1.3	520
Case 1B Natural Gas Electric	0.2%	HF	GWP 20	0.072	0.032	0.12	1.1	340
			GWP 100	0.072	0.012	0.089	1.1	330
		VF	GWP 20	0.090	0.054	0.14	1.2	580
			GWP 100	0.090	0.020	0.11	1.1	550
	2.3%	HF	GWP 20	0.072	0.50	0.58	2.4	720
			GWP 100	0.081	0.19	0.26	1.4	410
		VF	GWP 20	0.090	0.63	0.72	3.5	1,730
			GWP 100	0.090	0.23	0.32	1.5	730
	3.7%	HF	GWP 20	0.072	0.81	0.88	8.6	2,620
			GWP 100	0.072	0.30	0.37	1.6	480
		VF	GWP 20	0.090	1.0	1.1	N/A	Undefined: No Net Capture
			GWP 100	0.090	0.37	0.46	1.9	920

17. Direct and Embodied Emissions Analysis for Alternative Cases

Table S 16 displays the direct and embodied emissions comparison for each case in the main text. The method for calculating the embodied emissions and relevant references are outlined in Section 8. Table S 17 shows the one minus the take back parameter, x, which gives insight into the removal efficiency of the joint DAC and energy system. This is additionally provided for each of the three methane leakage rates discussed in the main text.

Table S 16: Gross and net removed cost including direct and embodied emissions for each alternative case (not including emissions from upstream methane leakage in the natural gas supply chain)

		Gross Capture Cost from Air [$/$tCO_2$]	Direct Emissions [tCO_2/tCO_2 removed]	Embodied Emissions [tCO_2/tCO_2 removed]	Net Removed Cost Including Direct & Embodied Emissions [$/$tCO_2$]
Case 1A Natural Gas	HF	$220	0.014	0.005	$230
	VF	$390	0.017	0.007	$400
Case 1B Natural Gas Electric	HF	$300	0.072	0.020	$330
	VF	$490	0.090	0.026	$560
Case 2A Solar (Annual Avg)	HF	$430	0	0.102	$480
	VF	$660	0	0.127	$750
Case 2B Solar (Seasonal Minimum)	HF	$460	0	0.147	$530
	VF	$690	0	0.183	$840
Case 3 Wind	HF	$360	0	0.053	$380
	VF	$570	0	0.066	$610
Case 4A Nuclear PWR	HF	$400	0	0.027	$410
	VF	$620	0	0.035	$640
Case 4B Modular Nuclear	HF	$370	0	0.027	$380
	VF	$570	0	0.035	$590
Case 5 Geothermal	HF	$250	0.049	0.029	$270
	VF	$440	0.061	0.037	$480

Table S 17: Embodied Emissions Impact Across Alternative Cases, including Fugitive Methane Emissions using a value of 2.3% from Alvarez et al. (2018) and a value of 3.7% from Zhang et al. (2020)

	Without Natural Gas Leakage		Alvarez et al. (2.3%) GWP100		Alvarez et al. (2.3%) GWP20		Zhang et al. (3.7%) GWP100		Zhang et al. (3.7%) GWP20	
	Net tCO_{2e} removed per tCO_2 removed from air (1-x)									
	HF	VF	HF	VF	HF	VF	HF	VF	HF	VF
1A	0.981	0.977	0.823	0.784	0.631	0.549	0.754	0.699	0.444	0.322
1B	0.904	0.884	0.647	0.562	0.330	0.169	0.533	0.420	0.023	-0.212
2A	0.898	0.873	0.898	0.873	0.898	0.873	0.898	0.873	0.898	0.873
2B	0.853	0.817	0.853	0.817	0.853	0.817	0.853	0.817	0.853	0.817
3	0.947	0.934	0.947	0.934	0.947	0.934	0.947	0.934	0.947	0.934
4A	0.973	0.965	0.973	0.965	0.973	0.965	0.973	0.965	0.973	0.965
4B	0.973	0.965	0.973	0.965	0.973	0.965	0.973	0.965	0.973	0.965
5	0.921	0.902	0.921	0.902	0.921	0.902	0.921	0.902	0.921	0.902

18. Comparing Cost Across Alternative Cases

Table S 18 displays a cross-case cost comparison from the cases. In this table, the natural gas emissions for 2.3% and 3.7% methane leakage are applied in addition to the embodied emissions for the DAC and energy system. Additionally, CO_2 emissions from the natural gas supply chain emissions are included in these estimates. These values differ from those displayed in Table 1 of the main text as the embodied emissions of energy generation, DAC, and CO_2 leakage in the methane supply chain are included in addition to the direct emission and methane leakage emissions.

Table S 18: Cost Comparison of the Alternative Scenarios Presented in this Analysis (Undefined indicates no net CO_2 capture)

					No Embodied Natural Gas		**With Alvarez et al Embodied Natural Gas (2.3%)**(Alvarez et al. 2018)				**With Zhang et al Embodied Natural Gas (3.7%)**(Zhang et al. 2020)			
			Direct Emissions Only		**Direct & Embodied Emissions**		**Direct, Embodied & Natural Gas GWP100**		**Direct, Embodied & Natural Gas GWP20**		**Direct, Embodied & Natural Gas GWP100**		**Direct, Embodied & Natural Gas GWP20**	
Case Number	**Gross Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]		**Net Removed Cost** [$/tCO$_2$]	
	HF	**VF**	**HF**	**VF**	**HF**	**VF**	**HF**	**VF**	**HF**	**VF**	**HF**	**VF**	**HF**	**VF**
1A	$220	$390	$230	$400	$230	$400	$270	$500	$350	$720	$300	$560	$500	$1,230
1B	$300	$490	$330	$540	$330	$570	$470	$880	$920	$2,920	$570	$1,170	13,080	Undefined
2A	$430	$660	$430	$660	$480	$750	$480	$750	$480	$750	$480	$750	$480	$750
2B	$460	$690	$460	$690	$530	$840	$530	$840	$530	$840	$530	$840	$530	$840
3	$360	$570	$360	$570	$380	$610	$380	$610	$380	$610	$380	$610	$380	$610
4A	$400	$620	$400	$620	$410	$640	$410	$640	$410	$640	$410	$640	$410	$640
4B	$370	$570	$370	$570	$380	$590	$380	$590	$380	$590	$380	$590	$380	$590
5	$250	$440	$270	$470	$270	$480	$270	$480	$270	$480	$270	$480	$270	$480

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Appendix A: Calculation Breakdown for Determining the Increment Cost of Point-Source CO_2 Capture from the EIA Data

Amount of CO_2 Captured:
All the calculated values must be put on a per tonne CO_2 captured basis. However, to do this, the amount of CO_2 captured from the system must be determined. The base CO_2 emissions from the NGCC plant with CCS is 117 lbs CO_2/mmBTU which is equivalent to 53.12 kg CO_2/mmBTU. Using the heating rate, the amount of CO_2 emissions per megawatt-hour can be determined:

$$CO_2 \text{ Emission } \left[\frac{\text{kg } CO_2}{\text{MWh}}\right] = 53.12 \frac{\text{kg}CO_2}{\text{mmBTU}} * 7493 \frac{\text{BTU}}{\text{kWh}} * 10^3 \frac{\text{mmBTU}}{\text{BTU}} = 338.4 \frac{\text{kg } CO_2}{\text{MWh}}$$

Assuming a 90% capture efficiency, the amount of CO_2 captured can be calculated:

$$CO_2 \text{ Captured } \left[\frac{\text{kg } CO_2}{\text{MWh}}\right] = 338.4 \frac{\text{kg } CO_2}{\text{MWh}} * 0.9 = 304.6 \frac{\text{kg}CO_2}{\text{MWh}}$$

The additional 10% of emissions are released from the process. This is equivalent to:

$$CO_2 \text{ Emitted } \left[\frac{\text{kg } CO_2}{\text{MWh}}\right] = 338.4 \frac{\text{kg } CO_2}{\text{MWh}} * 0.1 = 33.8 \frac{\text{kg}CO_2}{\text{MWh}}$$

The captured CO_2 for the CCS system can then be determined using the size of the NGCC plant in MWh. Here, the size in MWh is equivalent to the operational hours from Table S 2 (7884 hours/year) times the plant size in MW (377 MW).

$$\text{Size [MWh]} = 7884 \frac{\text{hours}}{\text{year}} * 377 \text{ MW} = 2{,}972{,}268 \text{ MWh}$$

$$\text{Total Captured } CO_2 \text{ [t}CO_2\text{]} = \frac{\text{Size [MWh]} * CO_2 \text{ Captured } \left[\frac{\text{kg } CO_2}{\text{MWh}}\right]}{10^3 \frac{\text{kg } CO_2}{\text{t}CO_2}}$$

$$\text{Total Captured } CO_2 \text{ [t}CO_2\text{]} = \frac{2{,}972{,}268 \text{ [MWh]} * 304.6 \left[\frac{\text{kg } CO_2}{\text{MWh}}\right]}{10^3 \frac{\text{kg } CO_2}{\text{t}CO_2}} = 1{,}012{,}269 \text{ t}CO_2$$

Capital Cost:
To determine the incremental capital cost of the system, the total cost for each base facility must be calculated:

$$\text{Total CAPEX [M\$]} = \frac{\text{Size [MW]} * \text{Total Overnight cost } \left[\frac{\$}{\text{kW}}\right] * 10^3 \left[\frac{\text{kW}}{\text{MW}}\right]}{10^6 \left[\frac{\$}{\text{M\$}}\right]}$$

$$\text{Total CAPEX NGCC [M\$]} = \frac{1083\ [\text{MW}] * \$954\ \left[\frac{\$}{\text{MW}}\right] * 10^3\left[\frac{\text{kW}}{\text{MW}}\right]}{10^6\ \left[\frac{\$}{\text{M\$}}\right]} = \text{M\$1,033.2}$$

$$\text{Total CAPEX NGCC with CCS [M\$]} = \frac{377\ [\text{MW}] * \$2{,}569\ \left[\frac{\$}{\text{MW}}\right] * 10^3\left[\frac{\text{kW}}{\text{MW}}\right]}{10^6\ \left[\frac{\$}{\text{M\$}}\right]} = \text{M\$968.5}$$

Since the two power plants are not of the same size, one must now be scaled for direct comparison. This scaling uses the same relationship as presented in Section 5. Here, the advanced NGCC (1,083 MW) is scaled to the size of the advanced NGCC with CCS (377 MW) using a scaling factor of 0.7.

$$\text{Scaled NGCC CAPEX} = \text{M\$1,033.2} * \left(\frac{377\ \text{MW}}{1083\ \text{MW}}\right)^{0.7} = \text{M\$493.6}$$

From here, the incremental capital cost can be determined.

$$\text{Incremental CAPEX [M\$]} = \text{Total CAPEX NGCC with CCS - Scaled NGCC CAPEX [M\$]-}$$

$$\text{Incremental CAPEX [M\$]} = \text{M\$968.5 - M\$493.6=M\$474.9}$$

This incremental capital cost can be used to determine the annualized capital cost. First, a lead time factor must be applied to account for the time it takes to build the NGCC plant. For both plants, this lead time is 3 years which corresponds to a cost factor of 1.155.

$$\text{CAPEX (including lead time) [M\$]} = \text{M\$474.9} * 1.155 = \text{M\$548.5}$$

From here the capital recovery factor can be used to determine the annual capital recovery. This factor can be found in Table S 2.

$$\text{Annual CAPEX [M\$]} = 0.105671 * \text{M\$548.5} = \text{M\$57.96}$$

Finally, the CAPEX can be put on a per tonne CO_2 captured basis using the 1,012,269 tCO_2 calculated in the previous section.

$$\text{Annual CAPEX}\ \left[\frac{\$}{\text{tCO}_2\ \text{Captured}}\right] = \frac{\text{M\$44.64} * 10^6\ \frac{\$}{\text{M\$}}}{1{,}012{,}269\ \text{tCO}_2\ \text{Captured}} = \frac{\mathbf{\$57.26}}{\mathbf{tCO_2\ Captured}}$$

Fixed OPEX:
Similar to the CAPEX, to determine the incremental fixed OPEX of the system, the total cost for each base facility must be calculated:

$$\text{Total Fixed OPEX [M\$]} = \frac{\text{Size [MW]} * \text{Fixed O\&M} \left[\frac{\$}{\text{kW*year}}\right] * 10^3 \frac{\text{kW}}{\text{MW}}}{10^6 \frac{\$}{\text{M\$}}}$$

$$\text{Total NGCC Fixed OPEX [M\$]} = \frac{1083 \text{ [MW]} * 12.15 \left[\frac{\$}{\text{kW*year}}\right] * 10^3 \frac{\text{kW}}{\text{MW}}}{10^6 \frac{\$}{\text{M\$}}} = \text{M\$13.16}$$

$$\text{Total NGCC with CCS Fixed OPEX [M\$]} = \frac{377 \text{ [MW]} * 27.48 \left[\frac{\$}{\text{kW*year}}\right] * 10^3 \frac{\text{kW}}{\text{MW}}}{10^6 \frac{\$}{\text{M\$}}} = \text{M\$10.36}$$

The NGCC must then be scaled to the size of the NGCC with CCS.

$$\text{Scaled NGCC CAPEX} = \text{M\$13.16} * \left(\frac{377 \text{ MW}}{1083 \text{ MW}}\right)^{0.7} = \text{M\$6.29}$$

From here, the incremental fixed OPEX can be determined.

$$\text{Incremental Fixed OPEX [M\$]} = \text{Total Fixed OPEX NGCC with CCS} - \text{Scaled NGCC Fixed OPEX [M\$]}$$

$$\text{Incremental Fixed OPEX [M\$]} = \text{M\$10.36} - \text{M\$6.29} = \text{M\$4.07}$$

Finally, the fixed OPEX can be put on a per tonne CO_2 captured basis using the 1,012,269 tCO_2 calculated previously.

$$\text{Fixed OPEX} \left[\frac{\$}{\text{tCO}_2 \text{ Captured}}\right] = \frac{\text{M\$6.73} * 10^6 \frac{\$}{\text{M\$}}}{1{,}012{,}269 \text{ tCO}_2 \text{ Captured}} = \frac{\mathbf{\$6.97}}{\mathbf{tCO_2 \text{ Captured}}}$$

Variable OPEX:
The incremental variable OPEX can be directly from Table S14 as it is not dependent on the scale of the energy facility.

$$\text{Incremental Variable OPEX} \left[\frac{\$}{\text{MWh}}\right] = \text{Variable OPEX NGCC with CCS} \left[\frac{\$}{\text{MWh}}\right] - \text{Variable OPEX NGCC} \left[\frac{\$}{\text{MWh}}\right]$$

$$\text{Incremental Variable OPEX} \left[\frac{\$}{\text{MWh}}\right] = 5.82 \left[\frac{\$}{\text{MWh}}\right] - 1.86 \left[\frac{\$}{\text{MWh}}\right] = 3.96 \left[\frac{\$}{\text{MWh}}\right]$$

This cost can then be used to determine the total variable OPEX for the CCS section.

$$\text{Total Variable OPEX [M\$]} = \frac{\text{Incremental Variable OPEX} \left[\frac{\$}{\text{MWh}}\right] * \text{Size [MWh]}}{10^6 \left[\frac{\$}{\text{M\$}}\right]}$$

$$\text{Total Variable OPEX [M\$]} = \frac{3.96\left[\frac{\$}{\text{MWh}}\right] * 2{,}972{,}268\ [\text{MWh}]}{10^6\ \left[\frac{\$}{\text{M\$}}\right]} = \text{M\$11.7}$$

Finally, the variable OPEX can be put on a per tonne CO_2 captured basis using the 1,012,269 tCO_2 calculated previously.

$$\text{Variable OPEX}\ \left[\frac{\$}{\text{tCO}_2\ \text{Captured}}\right] = \frac{\text{M\$11.7} * 10^6 \frac{\$}{\text{M\$}}}{1{,}012{,}269\ \text{tCO}_2\ \text{Captured}} = \frac{\mathbf{\$11.63}}{\mathbf{tCO_2\ Captured}}$$

Natural Gas Cost:
Assuming a natural gas cost of $3.43/mmBTU and an incremental natural gas requirement of 3.41 mmBTU/tCO_2 captured, the cost of natural gas can be calculated as:

$$\text{Incremental Natural Gas Cost}\ \left[\frac{\$}{\text{tCO}_2}\right] = \$3.43\ \left[\frac{1}{\text{mmBTU}}\right] * 3.41\ \left[\frac{\text{mmBTU}}{\text{tCO}_2\ \text{Captured}}\right] = \frac{\$11.70}{\text{tCO}_2\ \text{Captured}}$$

Total Incremental Cost of CCS for a NGCC:
The total incremental cost of CCS for the NGCC is equivalent to the sum of the four components in accordance with:

$$\text{Incremental CCS Cost}\ \left[\frac{\$}{\text{tCO}_2\ \text{Captured}}\right] = (\text{CAPEX} + \text{Fixed OPEX} + \text{Variable OPEX} + \text{Natural Gas Cost})\ \left[\frac{\$}{\text{tCO}_2\ \text{Captured}}\right]$$

$$\text{Incremental CCS Cost}\ \left[\frac{\$}{\text{tCO}_2\ \text{Captured}}\right] = \frac{\$57.26}{\text{tCO}_2\ \text{Captured}} + \frac{\$4.02}{\text{tCO}_2\ \text{Captured}} + \frac{\$11.63}{\text{tCO}_2\ \text{Capture}} + \frac{\$11.70}{\text{tCO}_2\ \text{Captured}}$$

$$\mathbf{\text{Incremental CCS Cost} = \frac{\$84.61}{tCO_2\ Captured}}$$