Supplementary Materials

To quantify gross and net sequestration potential and associated costs of BECCS, supply chain logistics and power generation were modeled. County-level potential biomass resources at specified years and prices were drawn from [1], and potential saline basins where BECCS is possible are delineated from geologic assessments [2] following Baik, *et al.* [3]. Sites suitable for power generation and BECCS within saline basins were modeled with Oak Ridge Siting Analysis for power Generation Expansion (OR-SAGE). Costs and emissions of biomass logistics and power generation were modeled with (BILT) and (IECM) respectively. Modeling assumptions regarding biomass resources, sequestration basins, BECCS locations, CO_2 supply chain emissions, injection wells and CO_2 storage, and power generation assumptions are described below. Detailed outputs are available at doi: 10.11578/1647453

1. CO_2 budget assumptions for the feedstock supply chain

Assumptions of CO_2 emissions from biomass production, harvest, pre-processing, transportation, estimated potential changes in soil organic carbon, and power generation are derived from various sources [4-7] and are shown in Table S1. Power for densification to make pellets is assumed to come from BECCs and is not burdened with CO_2 emissions.

Table S1. Summary of CO_2 emissions by feedstock and logistics step used in this analysis (energy cane and eucalyptus, comprising about 1% of supplies, assume emissions same as for switchgrass and poplar, respectively).

	CO_2				
		CO_2 emitted			
Feedstock	**CO_2 captured (kg CO_2 / dry tonne of biomass)[1]**	**Production and harvest (kg CO_2 / dry tonne of biomass)[2]**	**Power Gen (kg CO_2 / dry tonne of biomass)[3]**	**Transportation (kgs of CO_2 / dry tonne-km)[4]**	**Form**
Barley straw	1,205	73.0	133.90	0.1587	Pellet
				0.1785	Raw
Biomass sorghum	1,205	107.7	133.90	0.1587	Pellet
				0.1785	Raw
Corn stover	1,205	54.3	133.90	0.1587	Pellet
				0.1785	Raw
Hardwood, lowland logging residues	966	5.2	107.40	0.1586	Pellet
				0.2380	Raw
Hardwood, lowland whole trees	966	14.4	107.40	0.1586	Pellet
				0.2380	Raw
Hardwood, upland logging residues	966	5.3	107.40	0.1586	Pellet
				0.2380	Raw
Hardwood, upland whole trees	966	14.7	107.40	0.1586	Pellet
				0.2380	Raw
Miscanthus	1,326	84.9	147.40	0.1569	Pellet
				0.1680	Raw
Mixedwood logging residues	966	5.2	107.40	0.1586	Pellet
				0.2380	Raw
Mixedwood whole trees	966	15.2	107.40	0.1586	Pellet
				0.2380	Raw
Oats straw	1,205	42.9	133.90	0.1587	pellet
				0.1785	raw

Table S1. Summary of CO_2 emissions by feedstock and logistics step used in this analysis (continued).

Feedstock	CO_2				
	CO_2 captured (kg CO_2 / dry tonne of biomass)[1]	CO_2 emitted			
		Production and harvest (kg CO_2 / dry tonne of biomass)[2]	Power Gen (kg CO_2 / dry tonne of biomass)[3]	Transportation (kgs of CO_2 / dry tonne-km)[4]	Form
Pine	1,715	123.5	191.00	0.1586	pellet
				0.2380	raw
Poplar	966	64.1	107.40	0.1586	pellet
				0.2380	raw
Softwood, natural logging residues	966	5.2	107.40	0.1586	pellet
				0.2380	raw
Softwood, natural whole trees	966	14.7	107.40	0.1586	pellet
				0.2380	raw
Softwood, planted logging residues	966	5.4	107.40	0.1586	pellet
				0.2380	raw
Softwood, planted whole trees	966	16.6	107.40	0.1586	pellet
				0.2380	raw
Sorghum stubble	1,205	60.5	133.90	0.1587	pellet
				0.1785	raw
Switchgrass	1,326	61.3	147.40	0.1569	pellet
				0.1680	raw
Wheat straw	1,205	47.8	133.90	0.1587	pellet
				0.1785	raw
Willow	966	129.5	107.40	0.1586	pellet
				0.2380	raw

[1,3] Output from IECM [4].
[2] From Canter, Qin, Cai, Dunn, Wang and Scott [5], data for Figure 4.13 (b) downloaded from https://bioenergykdf.net/billionton2016vol2.
[4] Derived from [6] and [7]

2. Biomass resources

Table S2. Biomass resources (tonnes) by resource category, near-term (2020) scenario at specified prices ($ per tonne at farmgate or forest roadside). Base-case scenario for agricultural resources, and medium housing, low-energy demand for forestland resources. County-level data from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county.

Resource category	Resource	$44	$66	$88	$110
Crop residues	Barley straw	100,126	371,552	411,612	422,247
	Corn stover	24,169,531	90,583,596	100,795,046	103,177,816
	Oats straw	3,700	4,831	4,913	4,959
	Sorghum stubble	270,588	638,072	644,634	633,657
	Wheat straw	6,265,866	13,206,634	14,402,050	14,110,967

Table S2. Biomass resources (tonnes) by resource category, near-term (2020) scenario. Base-case scenario for agricultural resources, and medium housing, low-energy demand for forestland resources. County-level data from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county (continued).

Resource category	Resource	$44	$66	$88	$110
Logging residues	Hardwood, lowland logging residues	3,345,816	3,345,816	3,345,816	3,345,816
	Hardwood, upland logging residues	3,408,801	3,408,801	3,408,801	3,408,801
	Mixedwood logging residues	3,646,180	3,646,180	3,646,180	3,646,180
	Softwood, natural logging residues	5,231,772	5,231,772	5,231,772	5,231,772
	Softwood, planted logging residues	1,543,822	1,543,822	1,543,822	1,543,822
Whole trees	Hardwood, lowland whole trees	115,691	9,916,418	16,853,238	16,853,238
	Hardwood, upland whole trees	15,122	23,262,146	32,152,170	32,152,170
	Mixedwood whole trees	288,452	2,558,992	3,040,484	3,040,484
	Softwood, natural whole trees	427,998	16,076,980	19,456,943	19,456,943
	Softwood, planted whole trees	254,435	16,371,436	16,554,214	16,554,214
Grand Total		49,087,902	213,957,315	279,583,114	301,511,860

Table S3. Biomass resources (million tonnes) by resource category, long-term (2040) scenario. Reported by price ($ per tonne) at farmgate or forest roadside, i.e., after harvest but before delivery. Base-case scenario for agricultural resources, and medium housing, low-energy demand for forestland resources, from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county. County-level data from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county.

Resource category	Resource	$44	$66	$88	$110
Crop residues	Barley straw	382,389	516,298	567,344	588,206
	Corn stover	40,317,600	139,628,155	150,873,234	150,219,306
	Oats straw	6,016	7,394	6,902	6,849
	Wheat straw	11,146,108	18,928,318	17,915,401	17,958,335
	Sorghum stubble	771,932	955,544	1,045,769	980,226
Herbaceous energy crops	Energy cane	-	303,224	1,517,418	4,032,408
	Miscanthus	5,902,093	145,108,830	265,896,008	298,022,193
	Biomass sorghum	810,715	17,539,242	52,848,030	86,650,139
	Switchgrass	24,530,179	145,646,218	124,675,827	109,509,816

Table S3. Biomass resources (million tonnes) by resource category, long-term (2040) scenario. Reported by price ($ per tonne) at farmgate or forest roadside, i.e., after harvest but before delivery. Base-case scenario for agricultural resources, and medium housing, low-energy demand for forestland resources, from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county. County-level data from USDOE [1] downloaded from https://bioenergykdf.net/bt16-2-download-tool/county (continued)

Resource category	Resource	$44	$66	$88	$110
Logging residues	Hardwood, lowland logging residues	4,207,060	4,207,060	4,207,060	4,207,060
	Hardwood, upland logging residues	3,086,554	3,086,554	3,086,554	3,086,554
	Mixedwood logging residues	2,448,788	2,448,788	2,448,788	2,448,788
	Softwood, natural logging residues	7,433,366	7,433,366	7,433,366	7,433,366
	Softwood, planted logging residues	1,682,057	1,682,057	1,682,057	1,682,057
Whole trees	Hardwood, lowland whole trees	-	8,313,025	22,033,214	22,033,214
	Hardwood, upland whole trees	-	14,242,664	27,289,494	27,289,494
	Mixedwood whole trees	34,517	2,160,734	2,332,032	2,332,032
	Softwood, natural whole trees	-	15,472,124	19,785,994	19,785,994
	Softwood, planted whole trees	-	14,868,874	14,934,793	14,934,793
Woody energy crops	Eucalyptus	-	849,640	566,630	470,314
	Pine	-	107,618	15,468	3,468
	Poplar	7,694,059	40,691,264	37,467,006	42,242,718
	Willow	6,552,853	22,773,745	12,815,431	6,949,884
Grand Total		117,006,286	606,970,735	771,443,821	822,867,213

3. Selecting sequestration basins and potential BECCS locations

OR-SAGE was used to identify areas within or near potential sequestration basins that meet specified BECCS siting constraints. Siting was also constrained post hoc considering the saline basins for CCS that have been assessed by the USGS. These geological formations have been categorized as Storage Assessment Units (SAU)s according to capacity, depth and location for the continental US and Alaska. (U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team 2013). The assessed formations are a subset of NOGA 2003, further constrained to have depths to the top of the SAU between 3000 and 13000 ft (914-3962) deemed both accessible and also sufficiently deep to prevent inadvertent release (Brennan et al. 2010; USEPA 2010). EPA 2010) Further criteria used in the analysis are given in Brennan et al. (2010) and include factors such as permeability and salinity of the formation water, amongst others.

The majority of SAUs have surface projection data provided on the USGS website linked to the assessment report. However, about a third of the formations are not published. For these sites, we had to return to the original NOGA maps and compare them with the GIS model described earlier. Details of SAU selection are given in the Appendix. The overlaying grid has a resolution of 15 square km, which means that the sites for BECCS power plants will be within 15 km of an injection site, namely those sites that are co-located with the GIS constraints the SAU assessments in USGS 2013. In addition, the power plants are constrained to be at least 50 miles (80 km) apart, as this appears to be the distance in our simulations at which point plant proximity does not constrain our results. Future scenarios could relax this constraint and expand the geographic region for BECCS, taking into account transportation costs.

The result of the OR-SAGE model is a set of spatial areas that satisfy the criteria listed in Table 3. These areas are then discretized by overlaying a 15 meter x 15 meter grid, which results in a set of 4,061 potential power plant sites (Figure S1).

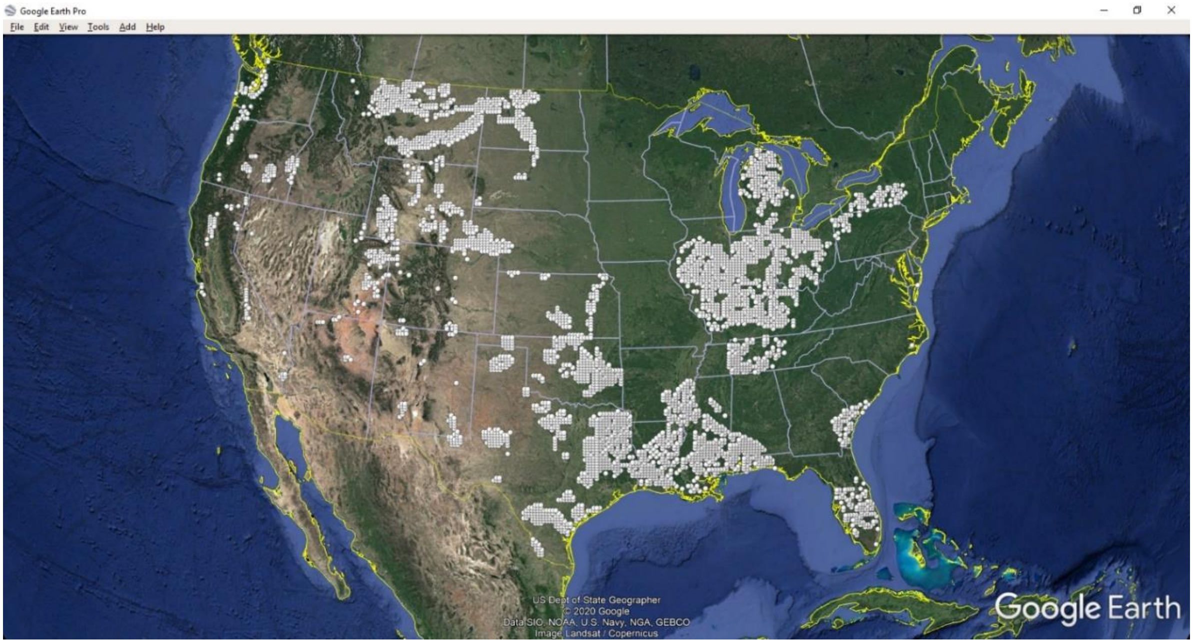

Figure S1. BECCS sites as selected in OR-SAGE.

These locations do not take into account the capability of the underlying geological formations to sequester the CO_2. The 2013 USGS storage assessment analysis [2] provides information for a number of areas that could support sequestration (Figure S2).

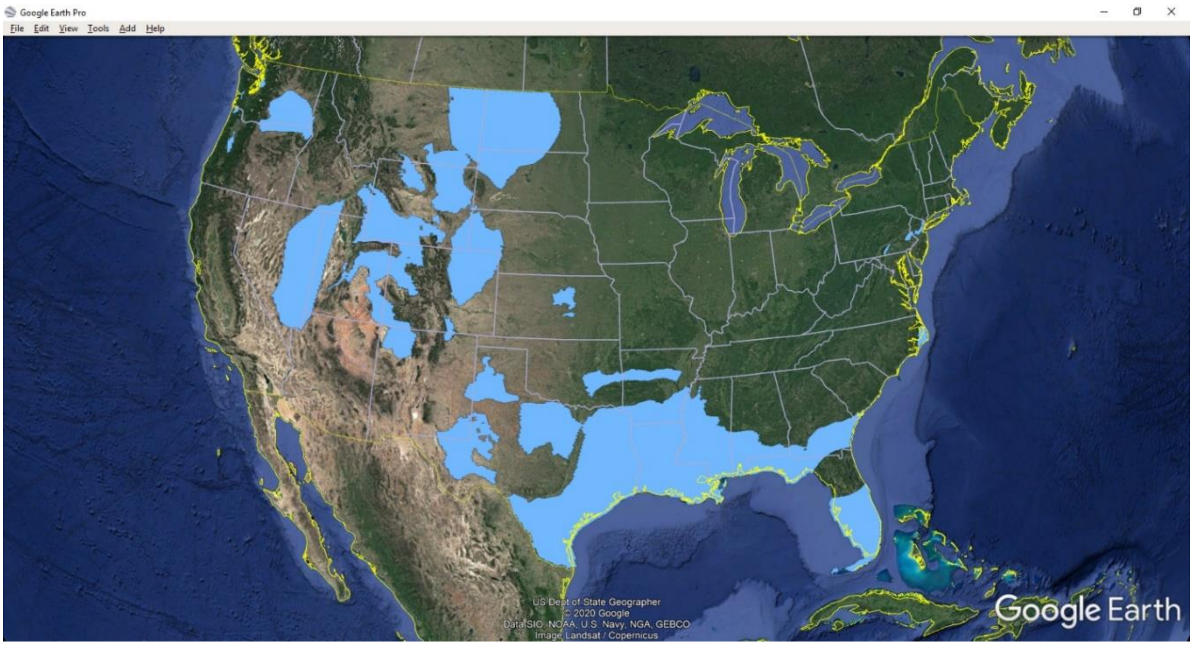

Figure S2. Basins identified in the USGS storage assessment [2].

For several of the areas, the assessment information has not been published. The province information from the USGS National Assessment of Oil and Gas Online [8] was used to provide geographical regions that could be used until the storage assessment unit is published. The suitable areas were selected based on mean formation depth, from 900 to 3700 m, and on having sufficient permeability as indicated by the presence of extractable oil or natural gas. Hydrocarbon production is accompanied by the extraction of formation water, or brine, which provides a medium for capturing CO_2 below ground. Gas-only producing formations have lower permeabilities than mixed oil and gas producing formations, but are considered viable for CO_2 capture (USGS 2013). The depth criteria have been established to ensure that injection sites are sufficiently deep to prevent leakage to the surface, but are not so deep as to make the injection of CO_2 difficult and the cost prohibitive. The resulting areas are shown in Figure S3. This still did not provide information for the Illinois Basin, and so for that basin, the area chosen for storage was from the following formations: Post-New Albany, Hunton, and Middle and Upper Ordovician Carbonate (Figure S4). The potential power plant sites from Figure S1 were then overlaid onto these regions to determine which sites would allow for sequestration without the need for piping the CO_2 to reach a suitable sequestration point. This resulted in 2,857 suitable sites (Figure S5). However, running BILT (a mixed integer programming model) on this many sites would overwhelm the model and preclude it from running to optimality in many cases, so this set was further reduced by thinning. The desired result of this thinning process was to obtain a subset of sites that spanned the same regions as the original set, but would allow BILT to run in a reasonable amount of time.

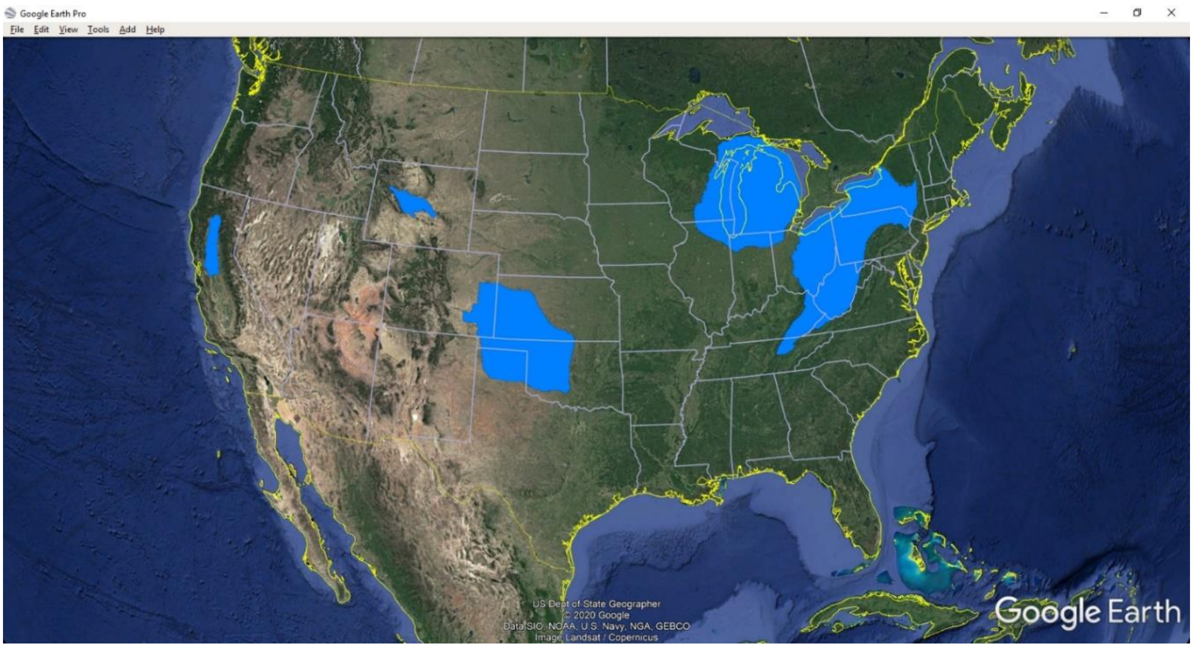

Figure S3. Basins identified in the USGS National Assessment of Oil and Gas Online [8].

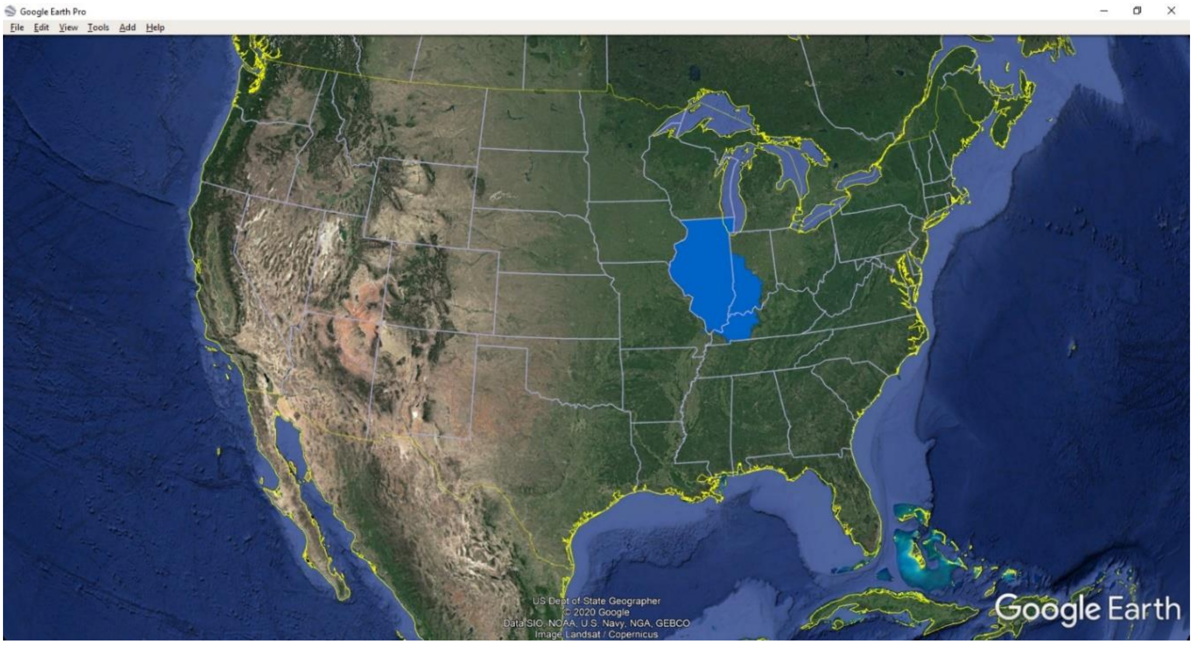

Figure S4. Post-New Albany, Hunton, and Middle and Upper Ordovician Carbonate formations.

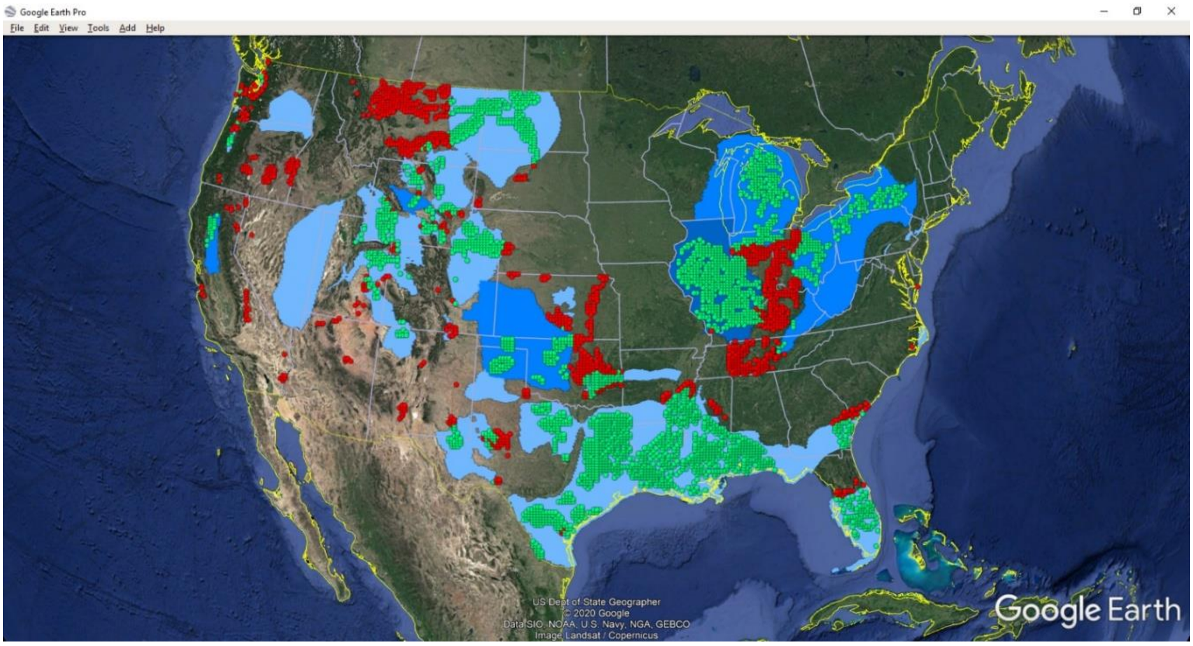

Figure S5. Potential power plant sites from Figure S1 overlaid potential sequestration basins.

The algorithm used to develop this smaller subset of potential power plant sites began by choosing the site that was located the furthest from any other site. This site was placed in set *S*. At each iteration of the process, the algorithm chose the site not in *S* that was the furthest from any site that was already in *S*. The process stopped when the site to be added was within a distance, *d*, from a site already in *S*. Larger values of *d* resulted in smaller subsets, and smaller values of d in larger subsets. The subset of 72 sites that results from a value of $d = 160$ km is shown in Figure S6. R-esults for $d = 121$ km and $d = 80$ km are shown in Figure S7 and Figure S8 producing 103 and 173 sites respectively. When BILT is run, by giving it more potential sites to choose among, the greater the confidence that it has chosen an optimal. Thus, the simulation of $d = 80$ km was used in the analysis.

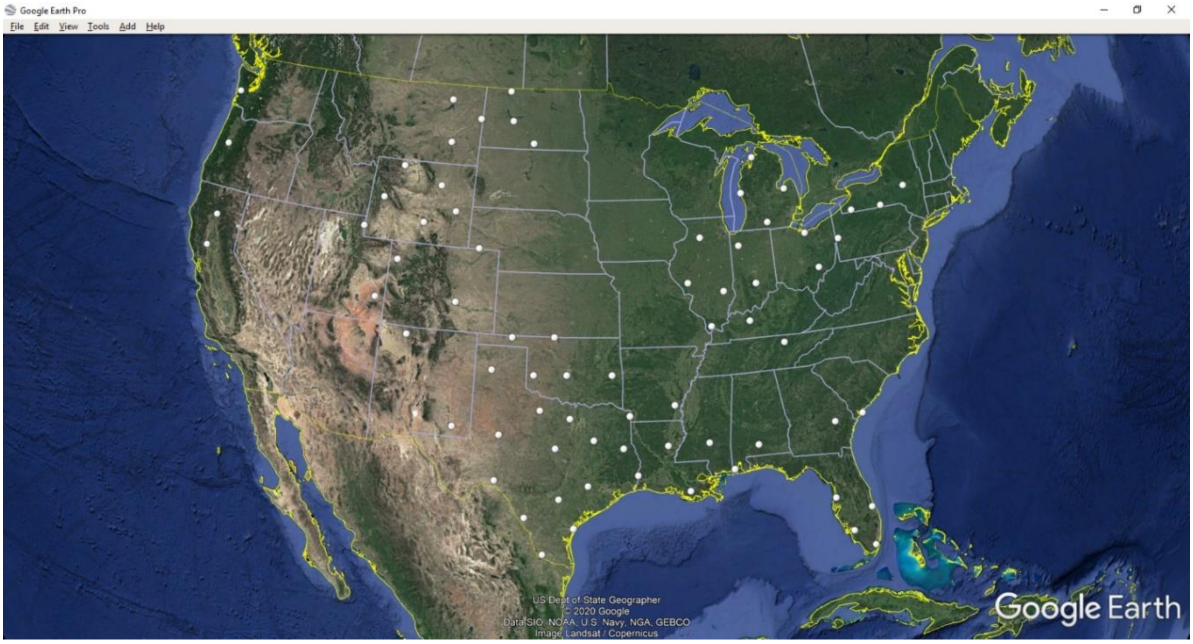

Figure S6. Potential sites thinned to distances of 160 km.

For d = 75 miles, the resulting set has 103 sites, and is shown here:

Figure S7. Potential sites thinned to distances of 121 km (103 sites).

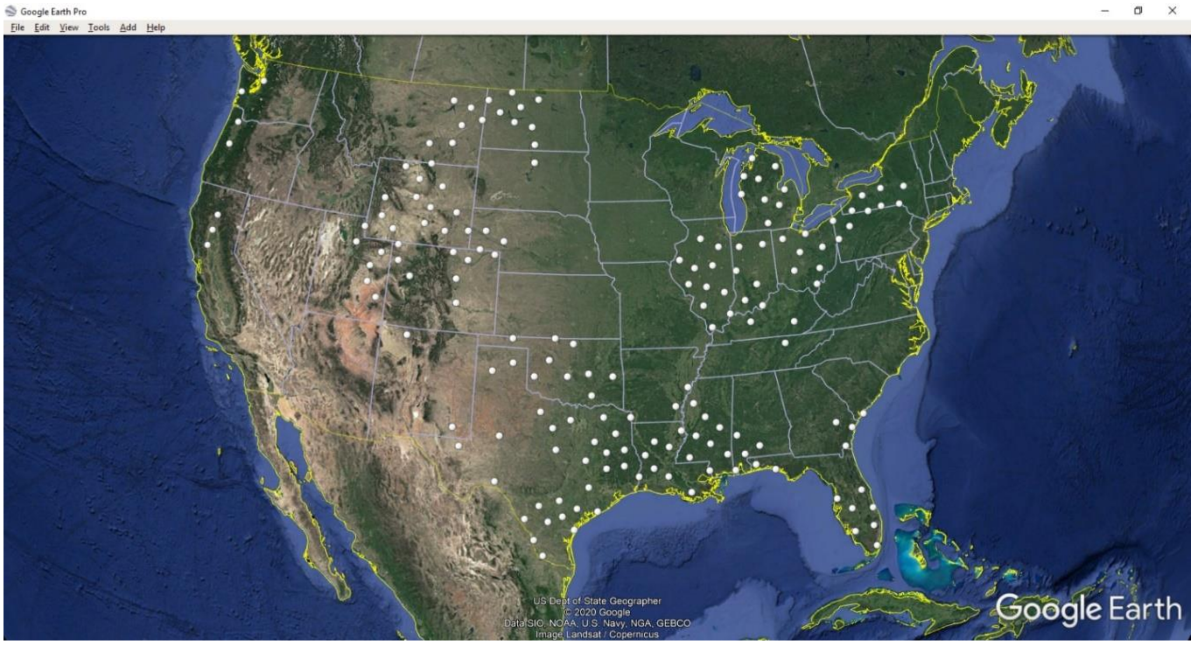

Figure S8. Potential sites thinned to distances of 80 km (173 sites).

4. Injection wells and underground storage of CO_2

CO_2 is typically injected as a supercritical fluid to increase its density to 600 kg/m^3, which reduces its buoyancy in the formation and increases the capacity of the formation. CO_2 captured from power production is compressed to a supercritical state and is transported to the injection site by pipeline, tanker truck, or ships.

The Environmental Protection Agency defined rules for injection wells for geologic sequestration of CO_2, Class VI wells, in 2010 [9] under the Safe Drinking Water Act (SWDA). The document provides minimum requirements that address: siting, construction, operation, testing, monitoring and closure. These requirements are to protect underground sources of drinking water. CO_2 has attributes that lead to specific requirements for underground injection: CO_2 is buoyant, mobile within the subsurface, corrosive when wet, and is a good solvent for a number of contaminants. CO_2 is expected to be injected in large volumes proximate to gas generation, larger than has been demonstrated in Enhanced Oil Recovery operations. Although all of these factor into costs of injection, for the purposes of the report, the geographical location relative to biopower installations and the capacity and injection rate are the factors that will be used to compare CCS from biopower versus that from other sources (steel and cement production, gas or coal fired generation. Injection of CO_2 into oil fields for advanced oil recovery are governed by a separate set of rules.

The costs of injection of CO_2 into sedimentary rocks has been estimated as \$7-13 t/CO_2 (2013 dollars) in the US. The range arises from attributes of the formation (depth, etc.) as well as land use, the number of injection wells, and requirements for monitoring.

i) Locations:

Underground injection is regulated by individual states. Those that have primacy under the SDWA can issue their own Class VI permits. Otherwise the Class VI permits are directed to the EPA regional authority, listed in Table S4. In certain states and tribal territories, tribal authorities authorize the permit. Although states have the opportunity to apply for primacy, it appears that this is being handled by the federal agency for all states except North Dakota [10]. The ND rule was approved on April 24, 2018. North Dakota made the application to support the bioenergy industry in general in the state, and specifically Red Trail Energy in development of CCS at its ethanol facility in Richardton. The application was supported by industry and academics alike [11], including the Energy and Environmental Research Center at the University of North Dakota, the Center for Carbon Removal and the Plains CO_2 Reduction (PCOR) Partnership.

Table S4. Responsibility for Class VI injection wells (November 2018).

EPA Region	States	Contacts
R1	CT, ME, MA, RI, NH, VT	No class VI wells
R2	NJ, NY, Puerto Rico, US Virgin Is.	Nicole Kraft, kraft.nicole@epa.gov, 212-637-3093
R3	PA, VA, WV, 7 tribes	Nobody specific for class VI
R4	AL, FL, GA, KY, MS, NC, SC, TN, 6 tribes	Larry Cole, cole.larry@epa.gov, 404-562-9474
R5	IL, IN, MN, OH, WI, 35 tribes	Andrew Greenhagen, greenhagen.andrew@epa.gov, 312-353-7648
R6	AR, LA, NM, OK, TX, 66 tribes	Brian Graves, graves.brian@epa.gov, 214-665-7193
R7	IA, KS, MO, NE	R7_uic_program@epa.gov
R8	CO, MT, ND, SD, UT, WY, 26 tribes	EPA except for ND, EPA contact is Wendy Cheung, cheung.wendy@epa.gov, 303-312-6242 latter is ND Industrial Commission, https://www.dmr.nd.gov/oilgas/
R9	AZ, CA, HI, NV, Pacific territories	Nobody specific for class VI
R10	AK, ID, OR, WA	Nate Fischer, natefischer@idwr.idaho.gov, Derek Sandoz, Sandoz.derek@deg.state.or.us Mary Shaleen Hansen, maha461@ecy.wa.gov

ii) Types:

EPA regulations cover Class VI wells, as well as those Class I, II, or V, wells that are converted to Class VI wells for geologic sequestration. Because of the physical and chemical nature of CO_2, regulations have been imposed for site characterization, well construction materials and ruggedness over the lifetime of the well.

CO_2 is injected in a permeable formation: sandstone or carbonate (dolomite, limestone), or mixtures. Downhole, the CO_2 will move and eventually be trapped by physical and geochemical processes that have been reviewed by Benson and Cole (2008) [12]. Injected CO_2 will rise in the formation until it contacts an impermeable layer. It will also reside in formation pores, perhaps as individual bubbles or droplets separated from the main plume by capillary forces. CO_2 can also dissolve into groundwater or hydrocarbons, and can reprecipitate as carbonate minerals. Finally, CO_2 can adsorb to organic-rich lithography displacing methane or other hydrocarbons, which is the reason why it is used for EOR. The nature of the reservoir will determine the relative rates of these processes and the suitability for long-term CO_2 sequestration. Attributes that either are advantageous or disadvantageous are given in

Table **S5**.

Assessment of the reservoirs was done using multi-scale physical models covering time scales from milliseconds to thousands of years. Data for these models have come laboratory experiments, which are not on the same scale, and model results have to be extrapolated beyond where they can be validated. Data on the subsurface geology is typically very scanty, requiring a geostatistical approach. Development of better tools to model CCS is ongoing, but because the models are not fully predictive, monitoring of CCS wells is of great importance.

Table S5. Attributes of Geologic Reservoirs for CO_2 Sequestration.

Advantageous	Disadvantageous
Being close to source of production (harvested forest residues associated with paper production, crop stover and agriculture residue, organic waste, and marginal farmland designated for energy crops)	Being far from production
Injection layer is porous – allows rapid injection rate (~1 million tonnes /year)	A tight formation, unless hydraulically fractured shales, means that injection rate is much lower.
Capacity 50-100 million tonnes/project	Lower capacity reduces economic feasiblity
Intact caprock (e.g., shale)	Migration pathways upwards: faults, fractures
Few penetrations from surface to disposal strata	Legacy wells that may have improper construction or inadequate plugging
Dry formation	Wet, allows CO_2 to dissolve, producing a corrosive solution that will flow with groundwater. Leaching of heavy metals is also possible
Dissolved CO_2 beneficial if it happens under conditions favorable to the formation of stable carbonate minerals	
Far away from drinking water reservoirs	Proximity to drinking water reservoirs may lead to contamination (with CO_2) because of the pressures used for injection. However, unlike fossil-energy produced CO_2, bioenergy plants will not co-produce H_2S or mercury compounds.
Deep formation (>800 m)	Shallow formation (<800m)
In situ mineralization (olivine, pyroxene), basaltic lavas and ultramafic rocks	Long distance from suitable formation, availability of rock formation. Changes in properties of the rock formation during injection create uncertainty: permeability, surface area, and changes in reaction rate through passivation.

Currently, biomass resources are concentrated around the eastern, western, and northern perimeter of the US, the upper Midwest and northern prairies (ND) and in states along with Mississippi River. The question is where these sources of biomass are close to areas acceptable for CO_2 injection. Some of these technologies have been developed for CCS of CO_2 from coal production funded by the US Department of Energy [13], particularly in saline aquifers and in advanced oil recovery [14].

Table S6. Operating CCS in 2018.

Bioenergy process (or other as noted)	Location/geology	Amount (million tonnes/year)
CO_2 (g) from ethanol (ADM)	Decatur, IL Mt. Simon Sandstone saline formation	0.9-1.0 starting in 2017
Biochar	Soil amendment - dispersed	39-77 t/y US 1.9-7.3 t/y Canada
Water saturated CO_2	Wallula, WA In-situ mineralization (828-886m)	977 tons
Fossil energy production	US depleted oil reserves, EOR	64 21 (from captured atmospheric CO_2)

iii) Injection rates

The injection rate will depend on the trapping mechanism for CO_2. There are four known phenomena that retain CO_2 underground [15].

1. Cap rock prevents migration of buoyant CO_2
2. The injected CO_2 dissolves into the formation brine. The brine becomes denser than non-CO_2 brines but CO_2 can migrate with groundwater.
3. Mineralization provides the most stable retention of CO_2; however, it make take ~10,000s of years to complete. Storage can last for 100,000s of years
4. Residual trapping is a process that takes place over days to months that can hold CO_2 over tens of years. Residual trapping depends on the relative permeability of CO_2 and residual gas saturation, or the fraction trapped in pore spaces.

Successful injection of CO_2 will require a reservoir of sufficient permeability, for instance 1 million tonnes/year. If the formation cannot handle the influx of CO_2 the pressure will rise beyond accepted levels and may result in a geomechanical deformation. The injection rate will be important if a reactive process needs to take place, such as in-situ mineralization. For the Wallula injection site, the CO_2 mineralization rate was 0.04 wt%/year, but this will depend on the characteristics of the formation.

iv) Injection capacities

A review by Dooley (2008) [16] estimated the geologic sequestration capacity in the US could be over 3500 Gt CO_2 with 95% of the largest conventional stationary sources only 50 miles from appropriate injection sites. The EPA assumes that CCS injection will be to depths greater than 800 m to maximize capacity and longevity of storage. According to the negative emissions report, the US consumes 100 EJ primary energy annually, or about the equivalence of 6.5 Gt CO_2. However, 1 Gt dry biomass is equivalent to 1.4 Gt CO_2 and 14 EJ according to the National Academies of Sciences, Engineering, and Medicine [17]. If the US was to assume its share of the IEA mandate for geologic sequestration, that would be ~2.1 Gt CO_2 sequestered annually by 2050, or CO_2 from the burning of 1.4 Gt biomass. The estimates for BECSS production in 2050 range from 522-1,500 million tonnes/year. A more realistic value for storage capacity of CO_2, with minimal effect on current land or water use is 6-17 Gt CO_2 by 2040. Enhanced oil recovery could take 30 Gt of CO_2. Hence, the ability to sequester CO_2 appears to comprise a small fraction of the overall capacity for CO_2 in the US subsurface.

Key to the viability of CO_2 injection though, is the proximity of the point of generation to the point of injection and the capacity of the proximate injection sites. The USGS assessed the framework for CO_2 injection across the US [18,19]. As part of this analysis, they considered the size of the formation, its porosity and permeability, and the presence of water or brine. These formations cover large areas of the US, but the distribution of capacity is not even. The mid continent and Alaska have much more capacity than coastal regions. The USGS also gives figures for the lands being federal, state, tribal, or privately owned, and the percentage off-shore. Who governs, owns access or has mineral rights to the land all affect the feasibility of injection, especially as sequestration sites may extend over 100 km^2. The USGS analysis found that formations off the Gulf Coast have the largest capacity for CO_2 injection, an estimated 1,800,000 million tonnes. The USGS estimates are highly dependent on the porosity and permeability of the formations, the porosity governing the capacity and the permeability governing the injection rate.

v) Costs

Costs have been evaluated for storage from ZEP 2019 [20]. Phases of storage include:

1. Exploration – not needed for DOGF, characterization, permitting, injection tests ($1m Euro)
2. Building facility – not needed for DOGF, development plan.
3. Injection, measure, monitor, and verify (4D seismic), highest risk
4. Closure – monitofring (targeted wells) and verification, liability fund. Decommissioning site

Storage costs are sensitive to the following: field capacity, well capacity (injectivity x lifetime of well), liability, well completion, depth, SACC, number observation wells, number exploration well. The variability in cost is mostly due to constraints in field capacity and well injectivity – the latter dictating the number of injectors. In general off-shore storage has been found to be more expensive, however, the brine reservoirs in the nearshore Gulf of Mexico have capacities that dwarf onshore formations. Well monitoring needs to cover well integrity, the injection of the CO_2, and its storage over the lifetime of the well, as well as groundwater quality in adjacent reservoirs during and after injection activities.

Regulations also ensure that injection sites have funds to cover monitoring and maintenance over the lifetime of the well. Record keeping is stipulated to assist emergency response if it is required and an ongoing environmental assessment of the area groundwater.

Various methods can be used to monitor CO_2 reservoirs [21]. Plumes of CO_2 injected underground can be followed by seismic imaging. Tracer gas, such as a freon, can be injected along with the CO_2. These non-natural gases can be detected at very low concentrations, to serve as a warning if the injected CO_2 has leaked into adjacent reservoirs, such as those that contain groundwater, or into monitoring wells. A water-soluble dye, fluorescein, has also been used. Monitoring C-12 to C-13 ratios gives an indication of the provenance of CO_2 in a formation or in an aquifer. CO_2 from biomass will have a different isotopic ratio than from burning fossil fuel.

Pressure sensors can be deployed in the injection well, as well as nearby monitoring wells. Pressure gives the response of the reservoir to the injected CO_2 as well as leakage into aquifers. Pressures that result in geomechanical events can be observed by interferometric synthetic aperture radar (In SAR) satellite images. Geophones that pick up seismic events can also be used as diagnostic tools. Induced seismicity can be problematic in certain injection sites.

4.1 Basin Capacities and Injection Costs.

Results from the BILT model gave locations of BECSS facilities with respect to possible injection sites located within 15 km of each power plant. These facilities have a range of sizes as has been discussed earlier, which translates to a range of CO_2 production values for capture and storage. The yearly average production of CO_2 for each of the BECCS facilities that were adjacent to a storage site were summed. Thus, the lifetime of the injection sites was computed based on this same production rate continuing indefinitely. The site lifetimes are show in **Table S7** below. Although the lower CO_2 projection scenarios produced much less CO_2 per annum, they also access far fewer sites. Thus, even the highest loadings of CO_2 can accommodate BECSS facility lifetimes of a few decades. The issue with the highest CO_2 production rates is that marginal injection sites are more likely to be accessed, for instance those with reduced permeability such as tight gas formations.

Table S7. Formation Lifetimes (years) as a Function of BECCS Scenario.

NOGA formation	10%	20%	30%	40%	50%	60%	70%	80%	90%	99%	100%
C5004						1338	1554	1202	798	1131	1002
C5020							236				1340
C5021											15157
C5022											892
C5030										49	51
C5031	3288		3241	6014	1680	1320	3409	2595	1945	1707	1628
C50310101		2612*									
C50310102		30547									
C5033							1403		671	1092	1037
C5034								1072		32	107
C5036											28698
C5037							13373				16094
C5039			450	450	225	148	75	87	50	57	50

Table S7. Formation Lifetimes (years) as a Function of BECCS Scenario (continued).

NOGA formation	10%	20%	30%	40%	50%	60%	70%	80%	90%	99%	100%
C5043	236	242		243	242	236	235	229	230	231	232
C5044			7339				7125	3486	3496	3434	3378
C5045		1852		625	460	455	455	455	455	608	459
C50475049	55875	23686	19015	15692	12395	10720	9383	7419	7995	7395	7075
C50490117	3303*										
C5050			18504	19587	18861	17614	18341	17792	2250	17194	23725
C5062		863	299	308	298	295	285	290	289	296	296
C5070		1644	1446	821	802	653	534	486	428	423	420
C5009							6470	406			6984
C5035							11696				
C5058	1712	1464	1415	1225	895	1011	876	870	875	874	876
C5063			3571	3585	3570	1720	1656	813	653	485	534
C5067		187	2161	805	773	424	304	270	209	181	170
C6401, 2, 4	4487	2287	2339	1689	1651	1193	1252	1089	1101	1088	1090

The cost of drilling an injection well has been based on those associated with oil and gas production, as these sites have been shown to have characteristics needed for CO_2 storage (USGS 2010). The cost of each well site has been determined using the formula provided by Lukawski, *et al.* [22], who fit API Joint Association Survey data between 1976 and 2009 and normalized costs to 2009 US$. We adjusted these 2009 costs to 2018 costs, as described elsewhere in this manuscript. The costs for each scenario are shown in the figure below. Although the overall drilling costs increase with the number of wells being drilled, and thus with the amount of CO_2 being injected, it is apparent that the costs for the 20-60% scenarios and the 70-90% scenarios are fairly flat. This suggests that the wells are equipped to accommodate higher production rates of CO_2, rather than more wells being drilled as one goes from 70-90% CO_2 for instance. Costs for drilling increase exponentially at 100% CO_2 production, as more marginal wells need to be accessed.

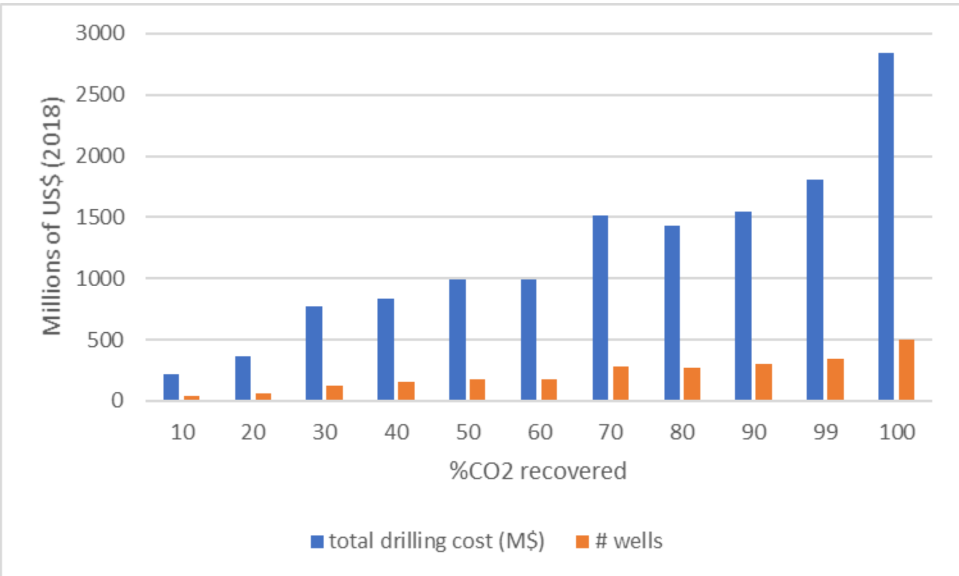

Figure S9. Injection cost and number of wells as a function of percent BECCS implemented.

4.2 *Coal retirement:*

Electric Utilities have been retiring hundreds of aging coal plants since 2010. The cost of building renewables, such as, wind (which has declined more than 40% in the same time period) and solar (which has declined more than 80% in the same time period), and having natural gas prices at historic lows as a result of the fracking boom is seeing coal plants being retired across the country. This has been further aggravated with the demand for electricity sharply falling in the spring of 2020, due to the nationwide shutdown to slow the spread of the Corona Virus.

With coal plants becoming more costly to operate than gas turbines and other renewables, utilities are pushing coal plants down the unit commitment dispatch stack. In the first four months of 2020, the US fleet of wind, solar and hydro generations have produced more electricity than coal on 90 separate days, shattering 2019's record of 38 days for the entire year. On May 1, 2020 in Texas and the ERCOT grid, wind generation supplied nearly three times as much electricity as coal did.

The latest report from DOE's Energy Information Administration (EIA) estimates that the US's total coal consumption will fall by nearly one quarter this year. Coal generation is estimated to provide just 19% of the nation's electricity in 2021, dropping for the first time below both Nuclear and Renewable generation. Renewables generation include – wind, solar, hydro, geothermal and biomass. Natural gas plants, which supplies 38% of the nation's electrical generation, is expected to hold the same output in the coming years due to low fuel prices.

EIA expects the US's emissions to fall an additional 11% (the largest drop in the last 70 years). This is driven partly by the new culture of "Work from Home" persisting, but more importantly because coal generation is being dispatched onto the grid less often. If coal does manage to beat expectations and rebound in the second half of the year, the dramatic shift in consumer behavior is unlikely to bring coal generation back into the mix. Duke Energy in the Southeast and Xcel Energy in the Midwest are in the process of retiring four dozen coal power plants by 2025 and no new coal facility are being built and commissioned. Coal is no longer considered "baseload" to the grid, a majority of which is covered by natural gas and nuclear generation. Natural gas additionally acts as a "hedge" to intermittent and uncertain generation resources such as wind and solar. For now, coal generation is expected to see a moderate rebound next year, as natural gas price keep low because of warm winter forecasts and reduced demand for gas heating.

5. Power generation assumptions

Power generation and associated CO_2 emissions, sequestration, costs, and power generation were modeled using the Integrated Environmental Control Model (IECM) [4]. Key modeling assumptions for the pulverized combustion (PC) system and the integrated gasification combined cycle (IGCC) system are described below. Using powerplant location, powerplant sizing, feedstock flow rates, and feedstock price outputs from the BILT model, the IECM model was used to calculate the following economic parameters: O&M costs (M$ per yr), annualized capital costs (M$ per yr), net power produced (MW), and revenue required to breakeven ($ per MWh). The chemical composition and energy density of the feedstock outputs from BILT were calculated by taking the weighted average of the composition and higher heating value data from the Phyllis biomass database [23].

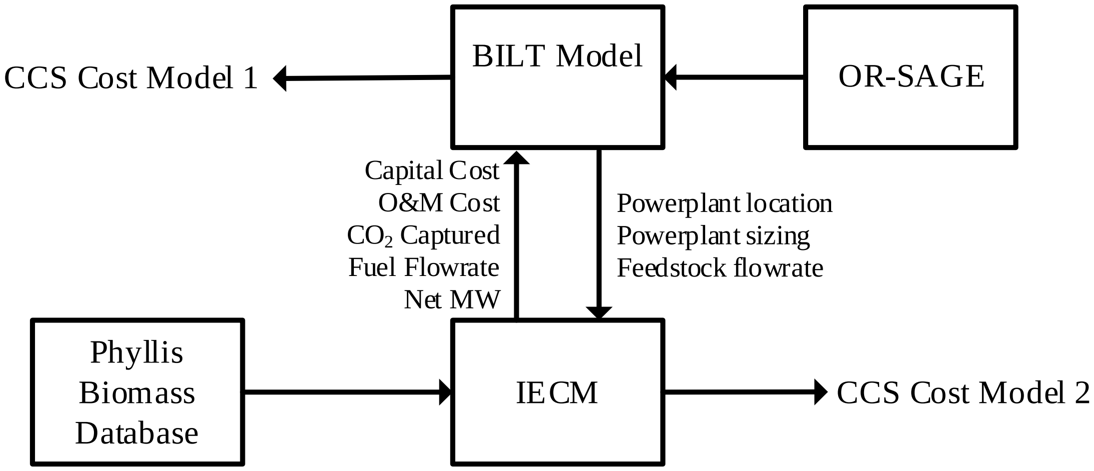

Figure S10. Logical pathway to BECCS cost calculations.

5.1 Pulverized Combustion

Pulverized coal (PC) powerplants can be converted to handle pelletized biomass feed [24]. Thus, the IECM was used to model PC powerplants running on pelletized biomass feed. The cost of building the powerplants is accounted for by IECM. The powerplants include the following emissions control technologies: post combustion CCS (using monoethanolamine, MEA), SOx and NOx control (using wet scrubbing and hot-side SCR), mercury control (using carbon injection), and particulates control (using cold-side electrostatic precipitation). The main units requiring specification in the base plant include the boiler, furnace, pulverizer, and steam cycle. Figure S11 presented below illustrates typical boiler performance on IECM.

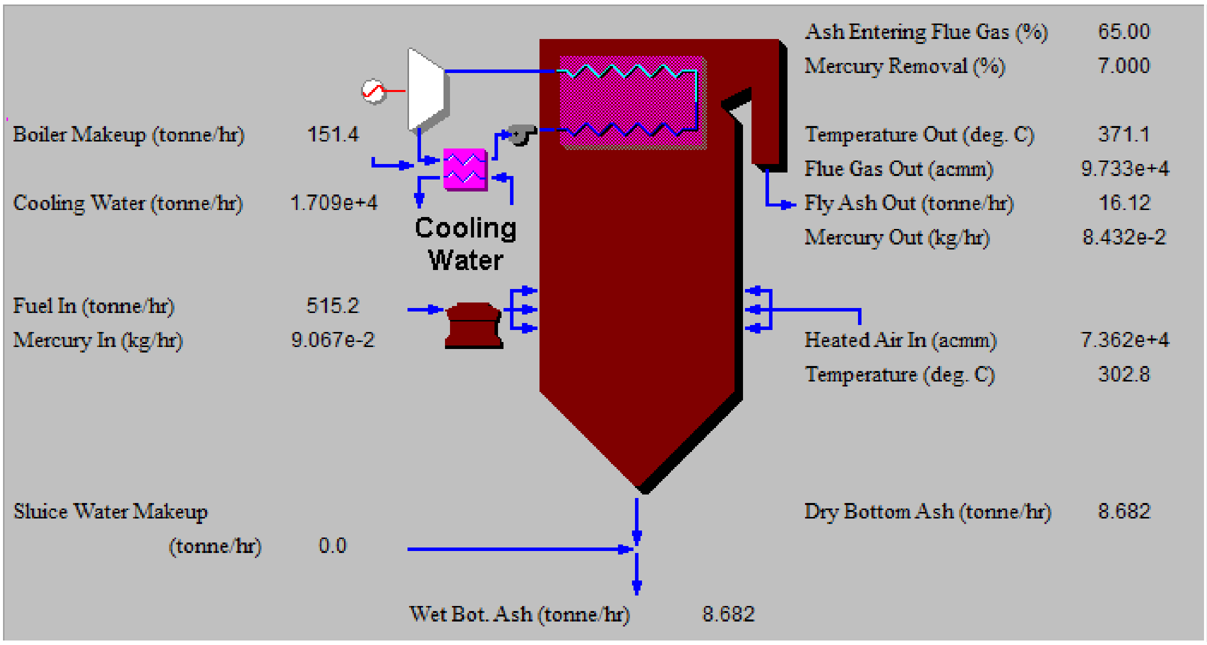

Figure S11. Example process flow diagram of a boiler on IECM [4].

The PC powerplants were modeled with the goal of capturing, transporting, and storing 90% of incoming CO_2 using chemical absorption with MEA. The capture was modelled using 30 wt% MEA which has a regeneration heat requirement of 4722 kJ/kg CO_2. The captured CO_2 is compressed to 13.79 MPa and then transported 100 km for storage in saline aquifers. Figure S12 illustrates typical performance of the absorption column containing MEA.

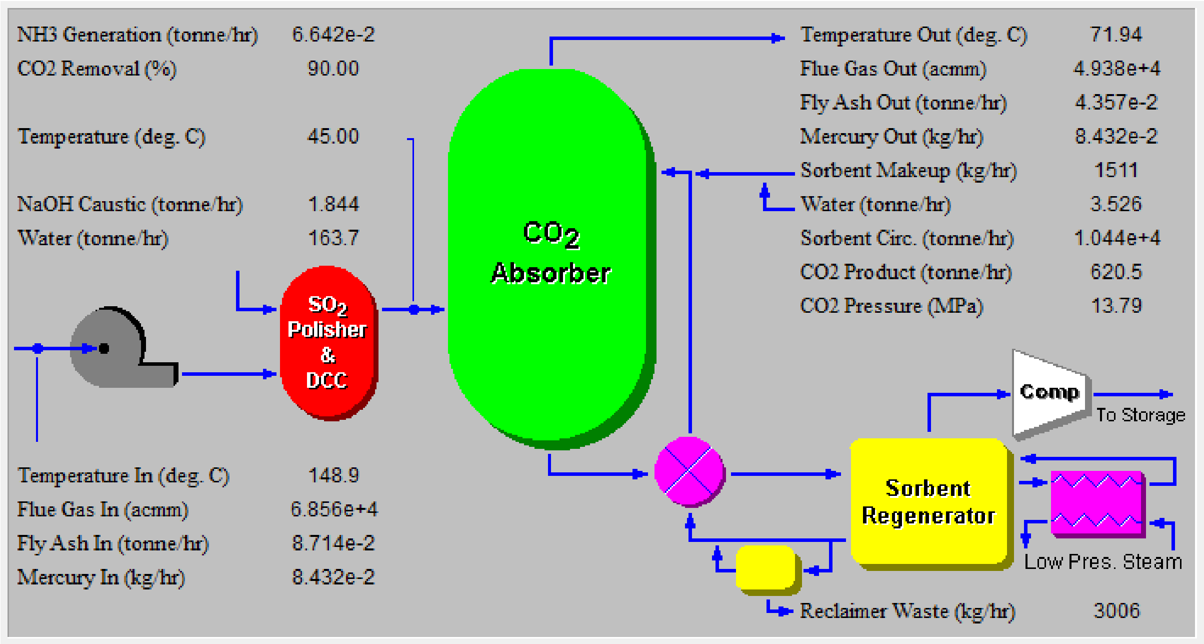

Figure S12. Example process flow diagram of CO_2 capture in a PC powerplant on IECM [4].

Values of parameters used in the simulations are shows in the tables below.

5.2 *Integrated gasification combined cycle*

Integrated Gasification Combined Cycle (IGCC) powerplants can run on pelletized and non-pelletized fuel [25]. IECM was used to simulate IGCC powerplants with pre-combustion CCS and H_2S control using Sour Shift + Selexol. The main units requiring specification in the base plant include the following: air separation unit, GE gasifier, sulfur removal unit (Selexol), CO_2 removal unit (Selexol), gas turbine (GE 7FB), air compressor, and combustor.

IGCC powerplants were modelled with 90% CO_2 removal and 94% H_2S removal in the Selexol process (Figure S13). The sour shift was favored over the sweet shift (in the sour shift, carbon is removed before sulfur) due to its lower steam demand [26]. Like with PC powerplants, the captured CO_2 is compressed to 13.79 MPa, transported 100 km and then stored underground.

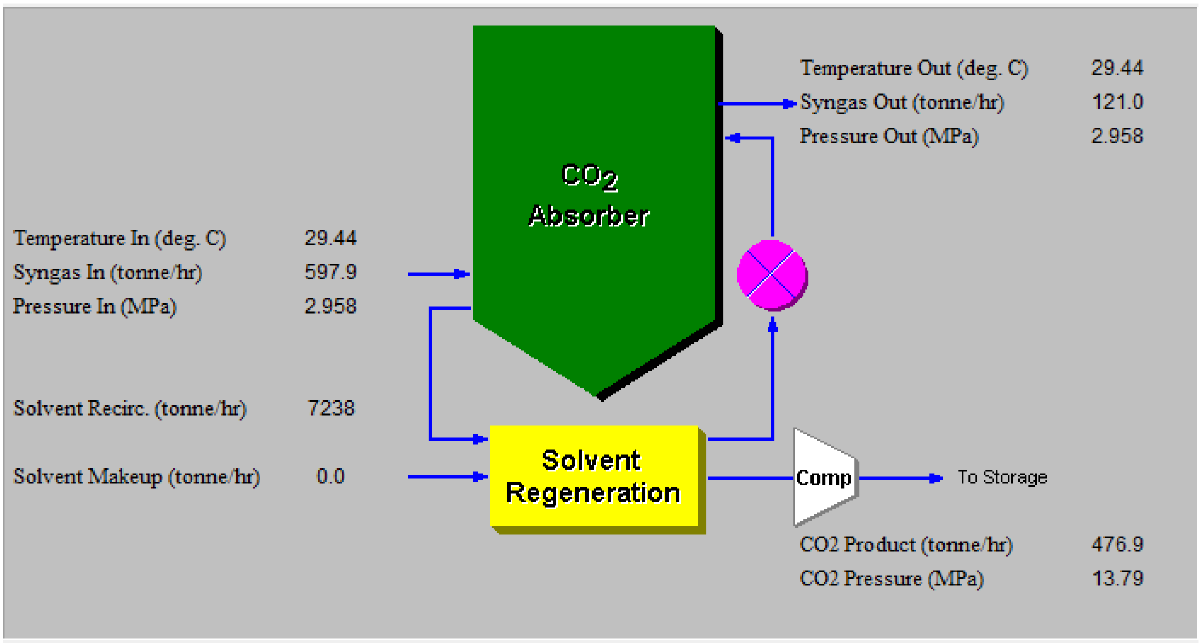

Figure S13. Example process flow diagram of the Selexol CO_2 capture process from IECM [4].

The BILT model and OR SAGE were used to determine the following key inputs for the IECM model: powerplant location, number of turbines, feedstock flowrates, and feedstock prices. The chemical composition and energy density of the fuel mixture was calculated by taking the weighted average of the composition and higher heating value data from the Phillys biomass database. In addition to the input fuel information, the IECM model also required detailed syngas composition leaving the gas separation unit [derived from 27,28-34]. This information can be found in Table S10, while Table S8 lists the values of parameters used to simulate IGCC powerplants in IECM.

Table S8. List of parameters used to simulate PC powerplants in IECM.

Variables	Value	Unit
Capacity factor	90%	
Ambient air temperature	18.89	C
ambient air pressure	0.10	MPa
relative humidity	50%	
water life cycle assesment enabled?	yes	
SO2 emission constraint	0.03	mg/kJ
NO2 emission constraint	0.22	mg/kJ
Particulate emission constraint	0.01	mh/kJ
Total mercury removal efficiency	70.00	
Total CO_2 removal efficienct	90.00	
tax on SO2	0.00	$/tonne
tax on NO2	0.00	$/tonne
tax on CO_2	0.00	$/tonne
Year costs reported	2017.00	
constant or current dollars	constant	
discount rate (before taxes)	0.07	
fixed charge factor	0.11	
plant or project book life	30.00	years
real bond interest rate	5.83%	
real preferred stock return	5.34%	
real common stock return	8.74%	
percent debt	45.00%	
percent equity (preferred stock)	10.00%	
oercebt equity (real stock)	45.00%	
federal tax rate	34.00%	
state tax rate	4.15%	
property tax rate	2.00%	
investment tax credit	0.00%	
as-delivered coal cost	0.00	$/tonne
natural gas cost	260.20	$/mscm
real escalation rate	0.00	%/yr
internal cost of electricity for component allocations	base plant	
internal electricty price	37.65	$/MWh
land cost use	3000.00	$/acre
total land requirement	0.52	acres/MWg
construction time	3.00	years
financing cost (%TCP)	0.00	
other owners costs (%TCP)	0.00	
activated carbon	2417.00	$/tonne
alum	407.70	$/tonne

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
ammonia	149.90	$/tonne
ccaustic	499.20	$/tonne
dibasic acid	639.30	$/tonne
flocculant polymer	4786.00	$/tonne
lime	110.30	$/tonne
limestone	25.39	$/tonne
MEA	2589.00	$/tonne
SCR catalyst	6003.00	$/cu m
Urea	559.40	$/tonne
Water	0.30	$/klitter
Hydrated lime	168.10	$/tonne
Taxes & insurance	0.00	
Operating labor rate	34.65	$/hr
Real escalation rate	0.00	%/yr
Gross Electrical Output		MWg
Unit type	Supercritical	
steam cycle heat rate (HHV)	1.09E+04	kJ/kWh
boiler firing type	tangential	
boiler efficiency	94%	
excess air for furnace	20	% stoich
leakage air at preheater	10	% stoich
gas temperature exiting economizer	371.1	deg C
gas temperature exiting air preheater	148.9	deg C
percent water in bottom ash sluice	0	
hydrated lime for so3 removal	1059	kg/kmol SO3
coal pulverizer	1.387	%MWg
steam cycle pumps	0.16	%MWg
forced/induced draft fans	3.891	%MWg
miscellaneuous	1.04	%MWg
steam energy added in Boiler	2680	kJ/kg
Boiler Blowdown	6%	
Miscellaneuos Steam Losses	0%	
Demineralizer Underflow	9%	
Cooling Water Temperature Rise	11.11	deg C
Auxiliary heat exchanger load	1%	
Percent ash entering flue gas stream	65%	
sulfur retained in flyash	25%	
percent of SOx as SO3	0.00056	
Preheater SO3 removal efficiency	10%	
Nitrogen Oxide emission rate	0.3049	mg/kJ
percent of NOx as NO	95%	
Concentration of Carbon in collected ash	0%	
percent of burned carbon as CO	0%	
Construction time	3.00	years
%PFC Allocated to Equipment	64%	%PFC
%PFC Allocated to Materials	2%	%PFC
General Facilities Capital	10%	%PFC
Engineering & Home Office Fees (E)	7%	%PFC
Process Contingency Cost (C)	2%	%PFC
Project Contingency Cost	10%	(%(PFC+E+C))

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Royalty Fees	0%	%PFC
Fixed Operating Cost	1	months
Variable Operating Cost	1	months
Miscellaneous Capital Cost	2%	%TPI
Inventory Capital	0%	%TPC
Financing Cost	0%	%TPC
Other Owner's Costs	0%	%TPC
% TCR Amortized	0%	
As-Delivered Coal Cost	0	($/tonne)
Waste Disposal Cost	11.7	($/tonne)
Water Cost	0.2983	($/kliter)
Hydrated Lime Cost	168.1	($/tonne)
Electricity Price (Internal)	37.65	($/MWh)
Number of Operating Jobs	20	
Number of Operating Shifts	4.75	(shifts/day)
Operating Labor Rate	34.65	($/hr)
Total Maintenance Cost	1.975	(%TPC)
Maintenance Cost Allocated to Labor	35	(%TMC)
Administrative & Support Cost	7	%total labor
Taxes & Insurance	0	%TPC
Actual NOx Removal Efficiency (%)	44.39%	
Maximum NOx Removal Efficiency (%)	50%	
Combustion Modifications	8.913	($/kw-gross)
Combustion Modifications	8.913	($/kw-gross)
% TCR Amortized (%)	0%	
Electricity Price (Internal)	37.65	($/MWh)
Combustion Modifications	1.50%	%TPC
Actual NOx Removal Efficiency	50%	
Maximum NOx Removal Efficiency	90%	
Particulate Removal Efficiency	0%	
Number of SCR Trains	2	
Number of Spare SCR Trains	0	
Number of Dummy Catalyst Layers	1	
Number of Initial Catalyst Layers	3	
Number of Reserve Catalyst Layers	0	
Catalyst Replacement Interval	1.00E+04	(hours)
Catalyst Space Velocity (1/hr)	4651	1/hr
Ammonia Stoichiometry	0.5089	
Steam to Ammonia Ratio (mol H2O/mol NH3)	19	(mol H2O/mol NH3)
Steam for Soot Ratio	6.78E-02	(lb-moles steam/cu m catalyst)
Total Pressure Drop Across SCR (cm H2O gauge)	22.86	
Oxidation of SO2 to SO3	0.63%	(vol%)
Hot-Side SCR Power Requirement (% MWg)	0.86%	
Space Velocity (1/hr)	2500	
Catalyst Replacement Interval (hours)	5694	
Ammonia Slip (ppmv)	2	
Temperature	644.4	(deg_K)
NOx Removal Efficiency (%)	80%	
NOx Concentration (ppmw)	500	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Minimum Activity (fraction)	0.5	
Reference Time (hours)	1.00E+04	
Activity at Reference Time (fraction)	0.85	
Ammonia Deposition on Preheater (%)	5%	
Ammonia Deposition on Fly Ash (%)	50%	
Ammonia in High Concentration Wash Water (mg/liter)	310	
Ammonia in Low Concentration Wash Water (mg/liter)	40	
Ammonia Removed from Wash Water (%)	67%	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	79.73%	
%PFC Allocated to Materials (%PFC)	0%	
General Facilities Capital (%PFC)	10%	
Engineering & Home Office Fees (E) (%PFC)	10%	
Process Contingency Cost (C) (%PFC)	7.12%	
Project Contingency Cost (%(PFC+E+C))	15%	
Royalty Fees (%PFC)	0%	
Months of Fixed O&M (months)	1	
Months of Variable O&M (months)	1	
Miscellaneous Capital Cost (%TPI)	2%	
Inventory Capital (%TPC)	0.50%	
Financing Cost (%TPC)	0%	
Other Owner's Costs (%TPC)	0%	
% TCR Amortized (%)	0%	
Catalyst Cost ($/cu m)	6003	
Ammonia Cost ($/tonne)	149.9	
Electricity Price (Internal) ($/MWh)	37.65	
Number of Operating Jobs (jobs/shift)	0.46	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65%	
Total Maintenance Cost (%TPC)	2%	
Maintenance Cost Allocated to Labor (% total)	40%	
Administrative & Support Cost (% total labor)	30%	
Taxes & Insurance (%TPC)	0%	
Particulate Removal Efficiency (%)	99.46	
Actual SO3 Removal Efficiency (%)	25	
Collector Plate Spacing (centimeters)	30.48	
Specific Collection Area (sq m/Macmm)	861.9	
Plate Area per T-R Set (sq m/T-R set)	2206	
Percent Water in ESP Discharge (%)	0	
Cold-Side ESP Power Requirement (% MWg)	0.2149	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	60.16	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	1	
Engineering & Home Office Fees (E) (%PFC)	5	
Process Contingency Cost (C) (%PFC)	0	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0	
Months of Fixed O&M (months)	1	
Months of Variable O&M (months)	1	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Miscellaneous Capital Cost (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Water Cost ($/kliter)	0.2983	
Waste Disposal Cost ($/tonne)	18.79	
Electricity Price (Internal) ($/MWh)	37.65	
Number of Operating Jobs (jobs/shift)	0.97	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	1.54	
Maintenance Cost Allocated to Labor (% total)	47.63	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	
System Used	MEA	
Auxiliary Gas Boiler?	None	
CO_2 Product Compressor Used?	Yes	
Compressor Type	6-stage	
Flue Gas Bypass Control	No Bypass	
Direct Contact Cooler (DCC) Used?	Yes	
SO_2 Polisher Used?	Yes	
SO2 Polisher Outlet Concentration (ppmv)	10	
Temperature Exiting DCC (deg. C)	45	
Maximum CO_2 Removal Efficiency (%)	90	
Absorber CO_2 Removal Efficiency (%)	90	
SO2 Removal Efficiency (%)	99.5	
SO3 Removal Efficiency (%)	99.5	
NO2 Removal Efficiency (%)	0	
HCl Removal Efficiency (%)	95	
Particulate Removal Efficiency (%)	50	
Maximum Train CO_2 Capacity (tonne/hr)	208.7	
Number of Operating Absorbers (integer)	3	
Number of Spare Absorbers	0	
Maximum CO_2 Compressor Capacity (tonne/hr)	299.4	
Number of Operating CO_2 Compressors (integer)	3	
Number of Spare CO_2 Compressors	0	
Amine Scrubber Power Requirement (% MWg)	19.16	
Sorbent Concentration (wt %)	30	
Lean CO_2 Loading (mol CO_2/mol sorb)	0.2	
Sorbent Losses (excluding acid gasses) (kg/tonne CO_2)	2.25	
Sorbent Recovered (kg/tonne CO_2)	0.1985	
Liquid-to-Gas Ratio (ratio)	3.741	
Ammonia Generation (mol NH3/mol sorb)	1	
Gas Phase Pressure Drop (MPa)	1.38E-02	
ID Fan Efficiency (%)	75	
Makeup Water for Wash Section (% raw flue gas)	0.8	
Activated Carbon Used (kg/tonne CO_2)	7.50E-02	
Regenerator Heat Requirement (kJ/kg CO_2)	4722	
Regenerator Steam Heat Content (kJ/kg steam)	3194	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Heat-to-Electricity Efficiency (%)	18.7	
Solvent Pumping Head (MPa)	0.2068	
Pump Efficiency (%)	75	
Percent Solids in Reclaimer Waste (%)	40	
Capture System Cooling Duty (t H2O/t CO_2)	104.3	
CO_2 Product Pressure (MPa)	13.79	
CO_2 Product Purity (vol %)	99.5	
CO_2 Compressor Efficiency (%)	80	
CO_2 Unit Compression Energy (kWh/tonne CO_2)	117.9	
CO_2 Transport Method	Pipeline	
CO_2 Storage Method	Geologic	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	76.64	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	10	
Engineering & Home Office Fees (E) (%PFC)	7	
Process Contingency Cost (C) (%PFC)	10	
Project Contingency Cost (%(PFC+E+C))	20	
Royalty Fees (%PFC)	0.5	
Months of Fixed O&M (Preproduction) (months)	1	
Months of Variable O&M (Preproduction) (months)	1	
Miscellaneous Capital Cost (Preproduction) (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Sorbent Cost ($/tonne)	2589	
Inhibitor Cost (% of MEA)	20	
Activated Carbon Cost ($/tonne)	2417	
Caustic (NaOH) Cost ($/tonne)	499.2	
Water Cost ($/kliter)	0.2983	
Reclaimer Waste Disposal Cost ($/tonne)	255.8	
Electricity Price (Internal) ($/MWh)	37.65	
CO_2 Transport Cost (Levelized) ($/tonne)	1.439	
CO_2 Storage Cost ($/tonne)	2.406	
Number of Operating Jobs (jobs/shift)	2	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	2.5	
Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	
Pipeline Region	Midwest US	
Total Pipeline Length (km)	100	
Net Pipeline Elevation Change (Plant->Inj.) (meters)	0	
Number of Booster Stations (integer)	0	
Compressor/Pump Driver	Electric	
Booster Pump Efficiency (%)	75	
Design Pipeline Flow (% plant cap)	100	
Design Pipeline Flow (tonne/yr)	5.44E+06	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Actual Pipeline Flow (tonne/yr)	4.90E+06	
Inlet Pressure (@ power plant) (MPa)	13.79	
Min Outlet Pressure (@ storage site) (MPa)	10.3	
Average Ground Temperature (deg. C)	5.6	
Pipe Material Roughness (centimeters)	4.57E-03	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	76.64	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	0	
Engineering & Home Office Fees (E) (%PFC)	0	
Process Contingency Cost (C) (%PFC)	0	
Project Contingency Cost (%(PFC+E+C))	0	
Royalty Fees (%PFC)	0	
Months of Fixed O&M (months)	0	
Months of Variable O&M (months)	0	
Miscellaneous Capital Cost (%TPI)	0	
Inventory Capital (%TPC)	0	
% TCR Amortized (%)	0	
Booster Pump Operating Cost (%PFC)	1.5	
Fixed O&M Cost ($/km-yr)	3100	
Reservoir Depth (meters)	1219	
Reservoir Thickness (meters)	304.8	
Reservoir Horizontal Permeability (mD)	100	
Reservoir Porosity (%)	12	
Storage Coefficient (%)	5.8	
Reservoir Surface Temperature (deg. C)	45.44	
Geographical Area for CO_2 Storage (sq km)	7.02E+04	
Performance Model	Law & Bachu	
Project Average Injection Rate (Mt CO_2/yr)	4.896	
Design Maximum Injection Rate per Well (Mt CO_2/yr)	6.12	
Monitoring Well Density		
Wells in Reservoir (sq km/well)	10.36	
Wells Above Seal (sq km/well)	5.18	
Wells that are Dual Completed (sq km/well)	10.36	
Wells Groundwater (Wells/Inj. Well)	3	
Wells Vadose Zone (Wells/Inj. Well)	3	
Dual Completed Wells in Reservoir (%)	100	
AOR Margin 3D (% of Plume)	30	
Regional Evaluation Duration (years)	1	
Site Characterization Duration (years)	1	
Permitting Duration (years)	1	
General Facilities Factor (%)	10	
Administrative Factor (E) (%)	10	
Process Contingency Factor (C) (%PFC)	20	
Project Contingency Factor (%(PFC+E+C))	20	
Miscellaneous Capital Cost (%TPI)	0	
% TCR Amortized (%)	0	
Operation Duration (years)	30	
Contingency Factor (%)	20	
Geophysical Survey: 3D Seismic ($/sq km)	6.18E+04	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Labor Rates		
Geologist ($/hr)	107.2	
Engineer ($/hr)	110.6	
Landman ($/hr)	75	
Miscellaneous Operations (%)	1	
PISC and Site Closure Duration (years)	50	
Well Seismic: VSP Tool Costs ($/well)	3.00E+05	
Miscellaneous PISC and Site Closure (%)	0.5	
Furnace Removal (total) (%)	7	
Cold-Side ESP (total w/o control) (%)	0	
Cold-Side ESP (oxidized) (%)	55.84	
Cold-Side ESP (elemental) (%)	55.84	
Wet FGD (oxidized) (%)	95	
Wet FGD (elemental) (%)	0	
Wet FGD (particulate) (%)	0	
Percent Increase in Speciation		
In-furnace NOx (oxidized) (%)	0	
SNCR (oxidized) (%)	0	
Hot-Side SCR (oxidized) (%)	35	
Carbon Injection Rate (*) (kg C/Macmm)	38.89	
Carbon Injection Power Reqmt (% MWg)	2.22E-02	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	63.82	
%PFC Allocated to Materials (%PFC)	2.46	
General Facilities Capital (%PFC)	5	
Engineering & Home Office Fees (E) (%PFC)	10	
Process Contingency Cost (C) (%PFC)	5	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0	
Fixed Operating Cost (months)	1	
Variable Operating Cost (months)	1	
Miscellaneous Capital Cost (%TPI)	2	
Inventory Capital (%TPC)	0.5	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Activated Carbon Cost (w. shipping) ($/tonne)	2417	
Disposal Cost ($/tonne)	18.79	
Electricity Price (Internal) ($/MWh)	37.31	
Number of Operating Jobs (jobs/shift)	0.175	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	1.48E-02	
Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	25	
Taxes & Insurance (%TPC)	0	
Reagent	Limestone	
Flue Gas Bypass Control	No Bypass	
Demister for Outlet Flue Gas	No Demister	
Maximum SO2 Removal Efficiency (%)	98	

Table S8. List of parameters used to simulate PC powerplants in IECM (continued).

Variables	Value	Unit
Scrubber SO_2 Removal Efficiency (%)	98	
Scrubber SO_3 Removal Efficiency (%)	50	
Particulate Removal Efficiency (%)	50	
Absorber Capacity (% acmm)	100	
Number of Operating Absorbers (integer)	1	
Number of Spare Absorbers	0	
Liquid-to-Gas Ratio (lpm/kacmm)	4.41E+04	
Reagent Stoichiometry (mol Ca/mol S rem)	1.03	
Reagent Purity (wt %)	92.4	
Reagent Moisture Content (wt %)	0	
Total Pressure Drop Across FGD (cm H_2O gauge)	25.4	
Temperature Rise Across ID Fan (deg. C)	7.778	
Gas Temperature Exiting Scrubber (deg. C)	62.33	
Gas Temperature Exiting Reheater (deg. C)	62.33	
Entrained Water Past Demister (% evap H_2O)	0.79	
Wet FGD Power Requirement (% MWg)	6.973	
Oxidation of $CaSO_3$ to $CaSO_4$ (%)	90	
Excess Air for Oxidation (% stoic)	0	
Excess Water for Oxidation (% stoic)	0	
Chloride Removal Efficiency (%)	90	
Construction Time (years)	3	
%PFC Allocated to Equipment (%PFC)	79.73	
%PFC Allocated to Materials (%PFC)	0	
General Facilities Capital (%PFC)	10	
Engineering & Home Office Fees (E) (%PFC)	10	
Process Contingency Cost (C) (%PFC)	2	
Project Contingency Cost (%(PFC+E+C))	15	
Royalty Fees (%PFC)	0.5	
Months of Fixed O&M (Preproduction) (months)	1	
Months of Variable O&M (Preproduction) (months)	1	
Miscellaneous Capital Cost (Preproduction) (%TPI)	2	
Inventory Capital (%TPC)	6.46E-02	
Financing Cost (%TPC)	0	
Other Owner's Costs (%TPC)	0	
% TCR Amortized (%)	0	
Bulk Reagent Storage Time (days)	60	
Limestone Cost ($/tonne)	25.39	
Lime Cost ($/tonne)	110.3	
Waste Disposal Cost ($/tonne)	14.47	
Electricity Price (Internal) ($/MWh)	37.31	
Number of Operating Jobs (jobs/shift)	6.67	
Number of Operating Shifts (shifts/day)	4.75	
Operating Labor Rate ($/hr)	34.65	
Total Maintenance Cost (%TPC)	4.467	
Maintenance Cost Allocated to Labor (% total)	40	
Administrative & Support Cost (% total labor)	30	
Taxes & Insurance (%TPC)	0	

Table S9. Complete list of parameters used to model IGCC powerplants on IECM.

Title	Value
Number of Gas Turbines	2
Gross Electrical Output (MWg)	630
Capacity Factor (%)	90
Process Water Demand Factor (l/MWh-net)	583
Ambient Air Temperature (Dry Bulb Average) (deg. C)	18.89
Ambient Air Pressure (MPa)	0.1014
Relative Humidity (Average) (%)	50
Ambient Air Humidity (kg H2O/kg dry air)	6.77E-03
Capital Cost Multipliers (ratio of Local/Default value)	
Construction Equipment Cost	1
Construction Materials Cost	1
Construction Labor Cost	1
Construction Labor Productivity	1
Seismicity Factor	1
Sulfur Dioxide (SO2) ($/tonne)	0
Nitrogen Oxide (Equivalent NO2) ($/tonne)	0
Carbon Dioxide (CO_2) ($/tonne)	0
Year Costs Reported	2017
Constant or Current Dollars?	Constant
Discount Rate (Before Taxes) (fraction)	7.09E-02
Fixed Charge Factor (FCF) (fraction)	0.1128
Plant or Project Book Life (years)	30
Real Bond Interest Rate (%)	5.83
Real Preferred Stock Return (%)	5.34
Real Common Stock Return (%)	8.74
Percent Debt (%)	45
Percent Equity (Preferred Stock) (%)	10
Percent Equity (Common Stock) (%)	45
Federal Tax Rate (%)	34
State Tax Rate (%)	4.15
Property Tax Rate (%)	2
Investment Tax Credit (%)	0
As-Delivered Coal Cost ($/tonne)	0
Auxiliary Gas Cost ($/mscm)	260.2
Real Escalation Rate (fuel) (%/yr)	0
Internal Cost of Electricity for Component Allocations	Base Plant
Internal Electricity Price ($/MWh)	10.76
Land Use Cost ($/acre)	3000
Total Land Requirement (acres/MWg)	0.517
Construction Time (years)	4
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
Activated Carbon Cost ($/tonne)	2417
Ammonia Cost ($/tonne)	149.9
Beavon-Stretford Catalyst Cost ($/cu m)	7151
Caustic (NaOH) Cost ($/tonne)	499.2
Claus Plant Catalyst Cost ($/tonne)	577.8
Glycol Cost ($/kg)	6.391
Shift Reactor Catalyst (Hi-T) ($/cu m)	2612

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
Shift Reactor Catalyst (Low-T) ($/cu m)	1.31E+04
Urea Cost ($/tonne)	559.4
Ionic Liquid Cost ($/tonne)	1.10E+04
Water Cost ($/kliter)	0.2983
Taxes & Insurance (%TPC)	0
Operating Labor Rate ($/hr)	34.65
Sulfur Byproduct Credit ($/tonne)	70.11
Real Escalation Rate (for all above) (%/yr)	0
Oxidant Composition	
Oxygen (O2) (vol %)	95
Argon (Ar) (vol %)	4.234
Nitrogen (N2) (vol %)	0.7657
Final Oxidant Pressure (MPa)	3.999
Maximum Train Capacity (tonne/hr)	550
Number of Operating Trains (integer)	1
Number of Spare Trains	0
Unit Separation ASU Energy (kWh/tonne)	6860
Total Cryogenic ASU Energy (% MWg)	1.53E-02
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	76.64
%PFC Allocated to Materials (%PFC)	0
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	5
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	2
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
Capital Cost Process Area	
Air Separation Unit (retro $/new $)	1
Final Oxidant Compression (retro $/new $)	1
Gasifier Area	
Gasifier Temperature (deg. C)	1343
Gasifier Pressure (MPa)	4.24
Total Water or Steam Input (mol H2O/mol C)	1.274
Oxygen Input from ASU (mol O2/mol C)	0
Total Carbon in Slag (%)	3

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
Sulfur Loss to Solids (%)	0
Coal Ash in Raw Syngas (%)	0
Percent Water in Slag Sluice (%)	0
Number of Operating Trains (integer)	1
Number of Spare Trains	1
Particulate Removal Efficiency (%)	100
Power Requirement (% MWg)	2.40E-06
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	63.82
%PFC Allocated to Materials (%PFC)	2.46
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	13.82
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	1
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Slag Disposal Cost ($/tonne)	17.73
Water Cost ($/kliter)	0.2983
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	4.225
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
COS to H2S Conversion Efficiency (%)	98.5
Sulfur Removal Unit	
H2S Removal Efficiency (%)	98
COS Removal Efficiency (%)	33
CO_2 Removal Efficiency (%)	0
Max Syngas Capacity per Train (tonne/hr)	225.2
Number of Operating Absorbers (integer)	2
Power Requirement (% MWg)	5.52E-02
Sulfur Recovery Efficiency (%)	95
Max Sulfur Capacity per Train (tonne/hr)	4.536
Number of Operating Absorbers (integer)	1
Power Requirement (% MWg)	6.89E-02
Tailgas Treatment	
Sulfur Recovery Efficiency (%)	99
Power Requirement (% MWg)	0.2097
Construction Time (years)	4

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
%PFC Allocated to Equipment (%PFC)	79.73
%PFC Allocated to Materials (%PFC)	0
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	79.73
%PFC Allocated to Materials (%PFC)	0
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Selexol Solvent Cost ($/kg)	6.391
Claus Plant Catalyst Cost ($/tonne)	577.8
Beavon-Stretford Catalyst Cost ($/cu m)	7151
Sulfur Byproduct Credit ($/tonne)	70.11
Sulfur Disposal Cost ($/tonne)	12.08
Sulfur Sold on Market (%)	90
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Total Maintenance Cost (%TPC)	1.961
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
COS Conversion System - Hydrolyzer (retro $/new $)	1
Sulfur Removal System - Selexol (retro $/new $)	1
Sulfur Recovery System - Claus (retro $/new $)	1
Tail Gas Treatment - Beavon-Stretford (retro $/new $)	1
Water-Gas Shift Reactor	
CO to CO_2 Conversion Efficiency (%)	95
COS to H2S Conversion Efficiency (%)	98.5

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
Steam Added (mol H2O/mol CO)	0.99
Maximum Train CO_2 Capacity (tonne/hr)	139.6
Number of Operating Absorbers (integer)	1
Number of Spare Absorbers	0
Thermal Energy Credit (% MWg)	3.87
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	76.64
%PFC Allocated to Materials (%PFC)	0
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	5
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
High Temperature Catalyst Cost ($/cu m)	2612
Low Temperature Catalyst Cost ($/cu m)	1.31E+04
Water Cost ($/kliter)	0.2983
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	1
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	1.969
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0
High Temperature Reactor (retro $/new $)	1
Low Temperature Reactor (retro $/new $)	1
Heat Exchangers (retro $/new $)	1
CO_2 Removal Efficiency (%)	90
H2S Removal Efficiency (%)	94
Max Syngas Capacity per Train (tonne/hr)	287.3
Number of Operating Absorbers (integer)	1
Number of Spare Absorbers	0
CO_2 Product Compressor Used?	Yes
Power Requirement (% MWg)	0
CO_2 Product Stream	
CO_2 Product Pressure (MPa)	13.79
CO_2 Compressor Efficiency (%)	80
CO_2 Unit Compression Energy (kWh/tonne CO_2)	0
CO_2 Transport Method	Pipeline
CO_2 Storage Method	Geologic
Construction Time (years)	4

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
%PFC Allocated to Equipment (%PFC)	76.64
%PFC Allocated to Materials (%PFC)	0
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	10
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Bulk Reagent Storage Time (days)	60
Glycol Cost ($/kg)	6.391
Waste Disposal Cost ($/tonne)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	2
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	4.902
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Gas Turbine/Generator	
Gas Turbine Model	GE 7FB
Number of Gas Turbines	2
Total Gas Turbine Output (MW)	0
Fuel Gas Moisture Content (vol %)	33
Turbine Inlet Temperature (deg. C)	1371
Turbine Back Pressure (MPa)	1.38E-02
Adiabatic Turbine Efficiency (%)	85.7
Shaft/Generator Efficiency (%)	98
Air Compressor	
Pressure Ratio (outlet/inlet) (ratio)	18.5
Adiabatic Compressor Efficiency (%)	87.5
Combustor	
Combustor Inlet Pressure (MPa)	1.875
Combustor Pressure Drop (MPa)	2.76E-02
Excess Air For Combustor (% stoich.)	0
HRSG Outlet Temperature (deg. C)	121.1
Steam Cycle Heat Rate, HHV (*1) (kJ/kWh)	9496
Cooling Water Temperature Rise (deg. C)	11.11
Auxiliary Heat Exchanger Load (*2) (%)	1.41
Total Steam Turbine Output (MWg)	0
Power Requirement (% MWg)	2
Construction Time (years)	4
%PFC Allocated to Equipment (%PFC)	63.82

Table S9. Complete list of parameters used to model IGCC powerplants on IECM (continued).

Title	Value
%PFC Allocated to Materials (%PFC)	2.46
(Remainder allocated to construction labor.)	
General Facilities Capital (%PFC)	15
Engineering & Home Office Fees (E) (%PFC)	10
Process Contingency Cost (C) (%PFC)	9.057
Project Contingency Cost (%(PFC+E+C))	15
Royalty Fees (%PFC)	0.5
Pre-Production Costs	
Months of Fixed O&M (months)	1
Months of Variable O&M (months)	1
Miscellaneous Capital Cost (%TPI)	2
Inventory Capital (%TPC)	0.5
Financing Cost (%TPC)	0
Other Owner's Costs (%TPC)	0
% TCR Amortized (%)	0
Electricity Price (Internal) ($/MWh)	10.76
Number of Operating Jobs (jobs/shift)	6.67
Number of Operating Shifts (shifts/day)	4.75
Operating Labor Rate ($/hr)	34.65
Total Maintenance Cost (%TPC)	1.472
Maintenance Cost Allocated to Labor (% total)	40
Administrative & Support Cost (% total labor)	30
Taxes & Insurance (%TPC)	0

Table S10. Syngas chemical composition of all feedstocks used.

	Barley Straw	Corn Stover	Hardwood	Miscanthus	Mixedwood	Oats Straw	Pine
1-C4H8	0.00	0.03	0.00	0.00	0.00	0.00	0.00
2-cis-C4H8	0.00	0.01	0.00	0.00	0.00	0.00	0.00
2-trans-C4H8	0.00	0.00	0.00	0.00	0.00	0.00	0.00
C2H2	0.00	0.19	0.00	0.00	0.00	0.00	0.00
C2H4	0.00	1.76	0.00	0.00	0.48	0.31	0.00
C2H6	0.00	0.00	0.00	0.00	0.00	1.23	0.00
C3H6	0.00	0.05	0.00	0.00	0.00	0.42	0.00
C3H8	0.00	0.17	0.00	0.00	0.00	0.01	0.00
CH4	0.31	6.43	1.30	3.90	3.59	8.53	4.79
CO	21.77	11.44	19.70	10.77	11.66	14.24	14.83
CO_2	0.42	9.95	11.90	9.84	7.13	8.55	14.20
COS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H2	18.42	11.30	9.10	17.50	19.15	8.70	8.19
H2O	0.93	0.00	0.00	0.00	0.00	0.00	0.00
H2S	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HCL	0.07	0.00	0.00	0.00	0.00	0.00	0.00
He	0.00	0.67	0.00	0.00	0.00	0.00	0.00
LHV	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NH3	0.00	0.00	0.00	0.00	0.00	0.00	0.00
O2	0.00	0.00	0.70	0.00	0.35	0.00	0.00

Table S10. Syngas chemical composition of all feedstocks used (continued).

	Barley Straw	Corn Stover	Hardwood	Miscanthus	Mixedwood	Oats Straw	Pine
N2	58.00	58.00	57.30	58.00	58.00	58.00	58.00
summation	99.92	100.00	100.00	100.00	100.35	100.00	100.00

	Poplar	Softwood	Sorghum	Switchgrass	Wheat Straw	Willow
1-C4H8	0.00	0.00	0.00	0.00	0.03	0.00
2-cis-C4H8	0.00	0.00	0.00	0.00	0.00	0.00
2-trans-C4H8	0.00	0.00	0.00	0.00	0.00	0.00
C2H2	0.00	0.00	0.00	0.00	0.13	0.00
C2H4	0.80	0.97	0.00	0.00	1.81	0.06
C2H6	0.04	0.00	0.42	0.00	0.00	0.07
C3H6	0.00	0.00	0.00	0.00	0.04	0.00
C3H8	0.00	0.00	0.00	0.00	0.34	0.03
CH4	3.61	5.88	4.11	3.90	6.85	1.51
CO	9.74	3.61	17.56	10.77	12.19	27.51
CO_2	8.74	2.35	14.06	9.84	9.24	3.79
COS	0.00	0.00	0.00	0.00	0.00	0.00
H2	19.07	29.19	5.24	17.50	10.67	8.30
H2O	0.00	0.00	0.00	0.00	0.00	0.00
H2S	0.00	0.00	0.00	0.00	0.03	0.00
HCL	0.00	0.00	0.00	0.00	0.00	0.00
He	0.00	0.00	0.00	0.00	0.67	0.00
LHV	0.00	0.00	0.00	0.00	0.00	0.00
NH3	0.00	0.00	0.00	0.00	0.00	0.00
O2	0.00	0.00	0.00	0.00	0.00	2.70
N2	58.00	58.00	58.61	58.00	58.00	56.00
Summation	100.00	100.00	100.00	100.00	100.00	99.97

Table S11. Chemical composition of non-pelletized feedstock.

Componenet	Moisture content	Ash content	C%	H%	N%	S%	O%	Cl ppm	LHV (MJ/kg)	HHV MJ/kg)
Barley Straw	10.00	4.50	41.85	5.03	0.47	0.11	37.51	5225.43	15.30	16.65
Corn stover	20.00	4.80	36.52	4.56	0.49	0.06	33.16	0.23	13.11	14.42
Hardwood	50.00	1.08	26.18	3.10	0.08	0.01	19.87	25.00	8.95	10.82
MixedWood	50.00	1.40	26.19	3.03	0.20	0.05	19.31	25.00	8.79	10.66
Oats Straw	10.00	6.18	42.27	4.82	0.54	0.09	36.97	7155.00	15.37	16.67
Pine	40.00	2.38	31.19	3.40	0.22	0.02	22.80	0.01	10.67	12.27
Poplar	40.00	1.06	29.28	3.58	0.17	0.03	25.86	0.02	10.04	11.54
Softwood	50.00	1.71	26.20	2.95	0.32	0.09	18.74	0.00	8.63	10.50
Sorghum	20.00	5.62	36.73	3.97	0.64	0.04	32.76	2293.33	13.10	14.47
Switchgrass	15.00	6.14	40.19	4.91	0.58	0.10	32.93	0.15	14.16	16.28
Miscanthus	15.00	6.14	40.19	4.91	0.58	0.10	32.93	0.15	14.16	16.28
Wheat Straw	10.00	4.99	41.36	5.05	1.00	0.10	36.83	3045.33	15.87	17.29
Willow	50.00	0.77	24.76	3.07	0.26	0.04	21.11	7.79	9.68	9.95

Table S12. Chemical composition of pelletized feedstock.

Component	Moisture (%)	Ash content (%)	C (%)	H (%)	N (%)	S (%)	O (%)	Cl (%)	LHV (MJ/kg)	HHV (kJ/kg)
Barley Straw	10.00	4.50	41.85	5.03	0.47	0.11	37.51	0.01	15.30	16830
Corn Stover	10	5.40	41.09	5.13	0.55	0.07	37.30	0.26	15.06	16566
Hardwood	10.00	1.35	47.13	5.58	0.15	0.01	35.77	0.00	18.06	19866
Miscanthus	9.00	6.57	43.03	5.25	0.63	0.10	35.25	0.00	15.33	16863
Mixedwood	10.00	2.22	47.14	5.45	0.36	0.09	34.75	0.05	17.78	19554.33
Oats Straw	10.00	6.18	42.27	4.82	0.54	0.09	36.97	0.01	15.37	16901.5
Pine	10.00	3.57	46.78	5.10	0.33	0.03	34.20	0.00	17.10	18810
Poplar	10.00	1.58	43.93	5.37	0.23	0.04	38.79	0.00	16.27	17901.4
Softwood	10.00	3.08	47.15	5.31	0.57	0.16	33.73	0.10	17.49	19242.67
Sorghum	10.00	6.33	41.32	4.47	0.73	0.04	36.86	0.00	15.04	16547.67
Switchgrass	9.00	6.57	43.03	5.25	0.63	0.10	35.25	0.00	15.33	16863
Wheat Straw	10.00	4.99	41.36	5.05	1.00	0.10	36.83	0.00	15.87	17453.33
Willow	10.00	1.39	44.57	5.52	0.47	0.04	38.00	0.00	15.97	17570.67

5.3 *Sensitivity analyses*

Sensitivity analyses were performed to identify parameters that the revenue required to breakeven was most sensitive to. The most sensitive parameters for both PC and IGCC are presented in Table S8 below and a complete list of parameters is shown in

Table **S14**. Sensitivity analyses were conducted by changing one input parameter by ±10% and measuring the change in an output variable, the revenue required to breakeven. Revenue required to breakeven was chosen as an apt output parameter since it provides a means of representing the total cost required to run a powerplant and the total power output. In future works, a multi-component sensitivity analysis will be performed by varying multiple parameters at once.

Sensitivity Analyses were evaluated using the following equation:

$$\text{Sensitivity} = \frac{\text{Revenue}_{\text{Base}} - \text{Revenue}_{\text{Sensitivty}}}{\text{Revenue}_{\text{Base}}} * 100 \quad (1)$$

Table S13. Most significant parameters determined from sensitivity analyses of pelletized pine. Parameters relevant to the CCS unit of the powerplant shown in bold.

PC	IGCC
Boiler Efficiency	Capacity Factor
Capacity Factor	Turbine Inlet Temperature
CO_2 Unit compression Energy	Feedstock Cost
Discount Rate	Plant or Project Book Life
Feedstock Cost	Total Carbon in Slag
Gas Phase Pressure Drop	
MEA Cost	
Plant or Project Book Life	
Regenerator Heat Requirement	
Sorbent Concentration	
Sorbent Losses	

Table S14. List of PC parameters tested in sensitivity analyses.

Fuel Cost	60
Capacity factor	90.00
Ambient air temperature	18.89
relative humidity	50.00%
discount rate (before taxes)	0.07
plant or project book life	30.00
land cost use	3000.00
total land requirement	0.52
construction time	3.00
activated carbon	2417.00
MEA	2589.00
SCR catalyst	6003.00
boiler efficiency	90.00
excess air for furnace	20.00
leakage air at preheater	10.00
Percent ash entering flue gas stream	65.00%
Sorbent Concentration (wt %)	30.00
Lean CO_2 Loading (mol CO_2/mol sorb)	0.20
Sorbent Losses (excluding acid gasses) (kg/tonne CO_2)	2.25
Sorbent Recovered (kg/tonne CO_2)	0.20
Gas Phase Pressure Drop (MPa)	0.01
ID Fan Efficiency (%)	75.00
Activated Carbon Used (kg/tonne CO_2)	0.08
Regenerator Heat Requirement (kJ/kg CO_2)	4722.00
Regenerator Steam Heat Content (kJ/kg steam)	3194.00
Pump Efficiency (%)	75.00
Percent Solids in Reclaimer Waste (%)	40.00
CO_2 Product Pressure (MPa)	13.79
CO_2 Compressor Efficiency (%)	80.00
CO_2 Unit Compression Energy (kWh/tonne CO_2)	117.90
Construction Time (years)	3.00
Sorbent Cost ($/tonne)	2589.00
Inhibitor Cost (% of MEA)	20.00
Activated Carbon Cost ($/tonne)	2417.00
Caustic (NaOH) Cost ($/tonne)	499.20
Water Cost ($/kliter)	0.30
Number of Operating Jobs (jobs/shift)	2.00
Number of Operating Shifts (shifts/day)	4.75
Total Pipeline Length (km)	100.00
Booster Pump Efficiency (%)	75.00
Design Pipeline Flow (tonne/yr)	5439000.00
Actual Pipeline Flow (tonne/yr)	4896000.00
Inlet Pressure (@ power plant) (MPa)	13.79
Min Outlet Pressure (@ storage site) (MPa)	10.30
Average Ground Temperature (deg. C)	5.60
Pipe Material Roughness (centimeters)	0.00
Construction Time (years)	3.00
Booster Pump Operating Cost (%PFC)	1.50
Fixed O&M Cost ($/km-yr)	3100.00
Reservoir Depth (meters)	1219.00
Reservoir Thickness (meters)	304.80

Table S14. List of PC parameters tested in sensitivity analyses (continued).

Reservoir Horizontal Permeability (mD)	100.00
Reservoir Porosity (%)	12.00
Storage Coefficient (%)	5.80
Reservoir Surface Temperature (deg. C)	45.44
Geographical Area for CO_2 Storage (sq km)	70190.00
Project Average Injection Rate (Mt CO_2/yr)	4.90
Design Maximum Injection Rate per Well (Mt CO_2/yr)	6.12
Operation Duration (years)	30.00
Miscellaneous Operations (%)	1.00
PISC and Site Closure Duration (years)	50.00
Well Seismic: VSP Tool Costs ($/well)	300000.00
Miscellaneous PISC and Site Closure (%)	0.50

Table S15. List of IGCC parameters tested in sensitivity analyses.

Parameter	Base Case
Capacity Factor (%)	90
Ambient Air Temperature (Dry Bulb Average) (deg. C)	18.89
Ambient Air Pressure (MPa)	0.1014
Relative Humidity (Average) (%)	50
Plant or Project Book Life (years)	30
Total Delivered Cost (as-fired) ($/tonne)	55.39
Oxygen (O2) (vol %)	95
Gasifier Temperature (deg. C)	1343
Gasifier Pressure (MPa)	4.24
Oxygen Input from ASU (mol O2/mol C)	0.4257
Total Carbon in Slag (%)	3
H2S Removal Efficiency (%)	98
Max Syngas Capacity per Train (tonne/hr)	225.2
Sulfur Recovery Efficiency (%)	95
H2S Removal Efficiency (%)	94
CO_2 Product Pressure (MPa)	13.79
Turbine Inlet Temperature (deg. C)	1371
HRSG Outlet Temperature (deg. C)	121.1

Table S16. Modeled LCOE and CO_2 emissions for the BECCs plants used to calculate CAC.

	PC 2040		**IGCC 2020**		**IGCC 2040 Conventional**		**IGCC 2040 Pellets**	
Scenario	$LCOE_{CCS}$	E_{CCS}	$LCOE_{CCS}$	E_{CCS}	$LCOE_{CCS}$	E_{CCS}	$LCOE_{CCS}$	E_{CCS}
1	144.49	1.37	141.12	-0.46	157.57	-0.96	131.80	-0.88
2	144.71	1.41	165.48	-0.55	139.39	-0.88	148.42	-0.90
3	145.04	1.42	151.97	-0.47	139.19	-0.86	131.26	-0.82
4	147.24	-1.43	176.16	-0.55	152.78	-0.90	144.16	-0.85
5	155.10	-1.42	173.68	-0.53	151.35	-0.89	147.72	-0.89
6	165.75	-1.41	176.93	-0.52	166.83	-0.93	149.73	-0.86
7	166.89	-1.42	162.65	-0.51	168.10	-0.91	161.96	-0.89
8	167.50	-1.40	165.33	-0.46	168.60	-0.88	168.54	-0.89
9	177.30	-1.40	184.19	-0.49	177.73	-0.86	180.00	-0.88
10	194.56	-1.35	216.67	-0.49	198.20	-0.84	195.35	-0.84
11	195.29	-1.34	219.09	-0.73	194.00	-0.85	195.97	-0.87

Table S17. Modeled LCOE and CO_2 emissions for the coal [35] and IGCC [36] reference plants used to calculate CAC.

		PC Coal Reference Case			NGCC Reference Case		
	Scenario	**$LCOE_{Base}$**	**$E_{Supply\ Chain}$**	**E_{Base}**	**$LCOE_{Base}$**	**$E_{Supply\ Chain}$**	**E_{Base}**
PC 2040 Pellets	1	43.00	0.061	0.82	61.96	0.025	0.36
	2	43.23	0.061	0.82	61.96	0.025	0.36
	3	43.12	0.061	0.82	61.96	0.025	0.36
	4	43.05	0.061	0.82	61.96	0.025	0.36
	5	43.00	0.061	0.82	61.96	0.025	0.36
	6	43.18	0.061	0.82	61.96	0.025	0.36
	7	43.17	0.061	0.82	61.96	0.025	0.36
	8	43.33	0.061	0.82	61.96	0.025	0.36
	9	43.64	0.061	0.82	61.96	0.025	0.36
IGCC 2020 Conventional	1	58.40	0.061	0.83	63.76	0.025	0.36
	2	58.40	0.061	0.83	63.76	0.025	0.36
	3	58.40	0.061	0.83	63.76	0.025	0.36
	4	58.40	0.061	0.83	63.76	0.025	0.36
	5	57.03	0.061	0.83	63.61	0.025	0.36
	6	56.15	0.061	0.83	63.52	0.025	0.36
	7	55.09	0.061	0.83	63.41	0.025	0.36
	8	55.54	0.061	0.83	63.45	0.025	0.36
	9	55.74	0.061	0.83	63.47	0.025	0.36
IGCC 2040 Conventional	1	58.40	0.061	0.83	63.76	0.025	0.36
	2	57.95	0.061	0.83	63.71	0.025	0.36
	3	56.07	0.061	0.83	63.51	0.025	0.36
	4	55.69	0.061	0.83	63.47	0.025	0.36
	5	53.32	0.061	0.83	63.21	0.025	0.36
	6	53.55	0.061	0.83	63.24	0.025	0.36
	7	51.91	0.061	0.82	63.05	0.025	0.36
	8	51.16	0.061	0.82	62.97	0.025	0.36
	9	50.41	0.061	0.82	62.88	0.025	0.36
IGCC 2040 Pellets	1	57.53	0.061	0.83	63.67	0.025	0.36
	2	56.65	0.061	0.83	63.57	0.025	0.36
	3	55.81	0.061	0.83	63.48	0.025	0.36
	4	55.17	0.061	0.83	63.42	0.025	0.36
	5	53.04	0.061	0.83	63.18	0.025	0.36
	6	52.07	0.061	0.82	63.07	0.025	0.36
	7	51.45	0.061	0.82	63.00	0.025	0.36
	8	50.51	0.061	0.82	62.89	0.025	0.36
	9	49.81	0.061	0.82	62.82	0.025	0.36

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