Princeton's Net-Zero America study

Annex I: CO_2 Transport and Storage Infrastructure transition analysis

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1 Introduction

All five of the core Net-Zero America (NZA) scenarios rely on substantial CO_2 capture, utilization and storage (CCUS) with 0.7 to 1.76 gigatonnes of CO_2 per annum being variously captured at cement plants, gas- and biomass-fired power generators, natural gas reforming units, biomass derived fuels and hydrogen production facilities, and in some cases direct from the atmosphere. Four of those five scenarios rely on large-scale geological sequestration (storage) of captured CO_2. The requirement for geological storage ranges from almost 1 to 1.7 gigatonnes of CO_2 per annum, servicing more than one thousand capture facilities distributed across the nation.

This appendix H describes the downscaling, siting and cost modelling for CO_2 transport and storage infrastructure in order to permanently sequester captured CO_2 streams identified in EER model outputs. The detailed downscaling of CO_2 transport and storage systems was undertaken for the E+ and E-B+ scenarios. Table 1 highlights the source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2050 under E+ and E-B+ scenarios. CO_2 flows in other NZAP scenarios are provided for comparison in Table 1. Table 20 through Table 25 provide source/sink flows being tracked as part of CO_2 pipeline sizing and siting for E+ and E-B+ scenarios from 2020 – 2050.

Table 1 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2050 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	**REF**	**E+**	**E-B+**	**E+B+**	**E+RE+**	**E+RE+B+**	**E-**	**E+RE-**	**E+RE-B+**
Biomass to hydrogen	0.0	642.1	964.2	843.2	181.8	470.1	573.4	611.8	633.0
Biomass to other hydrocarbons	0.0	88.8	54.3	0.5	241.1	53.0	104.1	28.8	0.9
Cement and lime manufacturing	0.0	138.4	138.4	138.4	138.4	138.4	138.4	138.4	138.4
Electricity generation (Biomass and fossil)	0.3	162.3	517.5	230.5	0.6	0.5	211.5	734.5	841.9
Subsurface carbon sequestration	-0.3	-929.1	-1361.0	-1160.0	0.0	0.0	-1484.3	-1649.5	-1697.0
ATR to hydrogen	0.0	29.1	3.6	13.4	0.0	0.0	8.6	148.4	92.4
DAC	0.0	0.1	0.1	0.0	127.3	0.0	723.2	8.7	0.0
Power-to-liquids	0.0	-131.6	-317.0	-65.9	-648.4	-648.5	-274.8	-20.9	-9.5
Power-to-gas methanation	0.0	0.0	0.0	0.0	-40.7	-13.5	0.0	0.0	0.0

CO_2 sinks listed in Table 1 include carbon sequestration in geological formations, or in synthetized liquid and gaseous hydrocarbons.

Downscaling efforts focused on siting and sizing CO_2 pipelines to connect point sources listed in the top half of Table 1, which are constrained to be located according to the geographic distribution of feedstocks, or energy demand, to suitable geologic formations for permanent subsurface storage. It was assumed that there will be considerably more flexibility in siting decisions for CO_2 sources and sinks listed in the bottom half of the table, and that the facilities serving those industries are able to utilize the proposed CO_2 transport infrastructure. For that reason, those facilities will not appear on NZAP maps.

The downscaling and siting of each of the CO_2 sources listed in the top half of Table 1 are described in detail in the appendices noted in Table 2.

Table 2 Appendices detailing the downscaling and siting of CO_2 sources in this analysis

Source	**Appendix**
BECCS to hydrogen	G. Siting bioconversion facilities
BECCS to other liquids	G. Siting bioconversion facilities
Cement and lime manufacturing	J. Cement industry scenario
Electricity generation - BECCS	G. Siting bioconversion facilities
Electricity generation - fossil	F. Siting thermal power plants

1.1 Overview of downscaling approach

CO_2 transport and storage infrastructure transition requirements were developed and downscaled according to the following sequence:

1. Notional CO_2 transport and storage cost curve for use in RIO energy systems model.

    1.1 The most prospective CO_2 storage basins selected based on practicable storage capacity (sustainable annual injection rates) estimates after Teletzke *et al*. (2018) [1].

    1.2 Notional capacity-cost curve for CO_2 transport and storage established using expert judgement and industry consultation (BP, ExxonMobil, Occidental), assuming shared transport infrastructure.

2. Downscaling CO_2 captured from point sources

    2.1 Rio Model chooses CCS to mitigate emissions from facilities in the power generation, fuels production and industry sectors across 14 E-Grid regions, where economically competitive for scenarios that allow CCS.

    2.2 Point sources for each sector downscaled temporally through the transition and geospatially across each of the 14 E-Grid regions to state/county level (see Appendices F, G and J).

3. Siting and costing CO_2 pipeline infrastructure

    3.1 Notional CO_2 transmission corridors located 'by eye' through creating catchment zones for major clusters of point sources in place in 2050, then realigned to nearest existing ROWs.[1]

[1] Existing ROWs include natural gas, NH3 and CO_2 pipelines, railways, interstate highways, and > 220kV electricity transmission lines, as mapped in Edwards and Celia, (2018) [2].

3.2 Point source downscaling (2.2) repeated to locate all point sources within 200 km of transmission lines.

3.3 Spur lines located to connect point sources to transmission lines using minimum distance and following existing ROWs.[1]

3.4 Transmission and spur line infrastructure sizing and cost estimates based on FE/NETL CO_2 Transport Cost Model.

4. Deployment schedules and unit cost estimates for CO_2 transport infrastructure

4.1 Pipeline build program developed in 5-year timesteps to deliver CO_2 transport capacity in advance of CCS requirement.

4.2 Spur lines deployment scheduled concomitantly with point sources/capture facilities.

4.3 Levelized cost of CO_2 transport established based on capital cost estimates, build schedules, and temporal profiles of CO_2 captured, using in-house discounted cash flow model.

4.4 CO_2 transport cost curves calculated for different potential capacity charge arrangements.

5. Development schedules and cost estimates for CO_2 injection infrastructure

5.1 Basin-wide precompetitive characterization and stakeholder engagement.

5.2 Appraisal and permitting of injection sites.

5.3 Estimation of unit costs of storage - levelized cost of development, and ongoing injection.

6. CO_2 transport and storage unit costs and supply curve (for high level comparison with notional capacity-cost curve used in step 3)

2 Notional CO_2 transport and storage cost curve

A key determinant in the potential scale of CCS and the pace at which deployment can be expanded is the finding, permitting, and development of subsurface geologic storage capacity. CO_2 storage resources are potentially available in depleted oil and gas reservoirs, deep saline sedimentary formations, deep saline basalt formations and coal seams [3].

While much of the possible CO_2 geologic storage is expected to occur in onshore areas, a significant amount of injection could occur offshore [4]. In fact, offshore storage may be less exposed to land access challenges, public opposition, permitting difficulties, containment uncertainties associated with legacy wells (a significant issue for most onshore basins which have seen extensive oil & gas extraction), and treatment/disposal of extracted formation water when managing reservoir pressure.

While the geologic storage resource potential is very large in the US, CO_2 storage reserves, or investable, rate-matched CO_2 storage capacity profiles remain **highly uncertain**. This discussion is consistent with the CO_2 Storage Resources Management System recently introduced by the Society of Petroleum Engineers [5].

This appendix describes two potential estimates for US CO_2 storage reserves in 2050 – base case and optimistic.

2.1 Static-based CO_2 Storage Assessments

There are many published estimates of the potential CO_2 storage *resource* in the US and other regions [6]–[8]. The USGS (Figure 1) refers to such estimates as *Technically Accessible Storage Resources.*

These estimates are based on gross, static pore volumes adjusted using a notional efficiency factor.

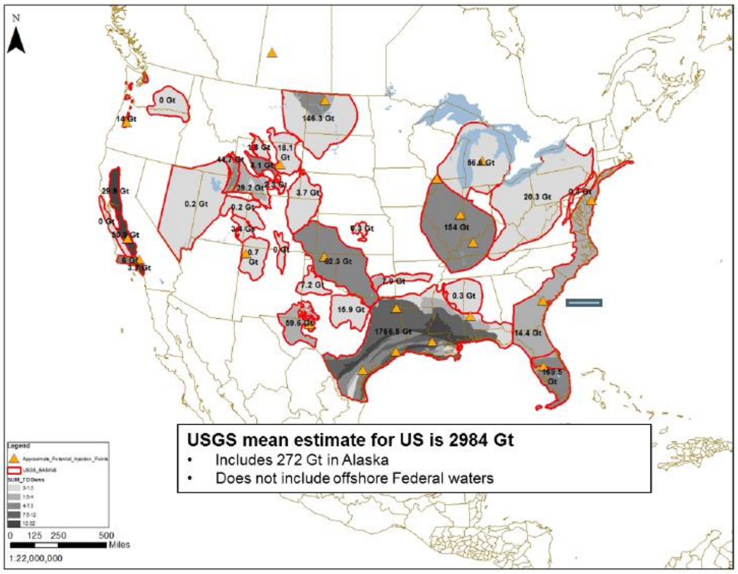

Figure 1 USGS assessment of Technically Accessible CO_2 Storage Resources. - US Onshore and State Waters. Darker shading represents increasing storage density (Mt per square mile) - after Teletzke et al. (2018) [1]

2.2 CO_2 storage resources, reserves and rate-matched, injection profiles

Static CO_2 storage assessments are not analogous to reserves. They might be considered more analogous to 'original oil in place' which are 'corrected pore volume' estimates. They assume all technical measures will be applied to achieve full utilization of accessible pore space and that injection rates and timeframes as well as costs are not important.

Reserves data are inherently dynamic assessments (with an economic filter) - they are related to pore volumes via "recovery factors" which are also published [Recovery factor (RF) in oil & gas production is the fraction of original oil in place, which can be economically produced]. Such recovery factors, however, do not correlate well with resource or reserves size but tend to be related to reservoir complexity, dependent on thickness, permeability, lateral and vertical heterogeneity, geomechanical features, etc. The average RF from mature oilfields around the world is typically between 20% and 40% whereas a typical RF from gas fields is between 80% and 90% [9]. In turn, standard reserves estimates correlate with *peak* production rate, but not with production decline rate [10] – both of which are necessary to project production over time. Figure 2 illustrates the oil production analog.

In the case of CO_2 storage, injection rate declines as the pressure in the formation increases. To maintain the storage rate equal to the capture rate: the pressure may be reduced (e.g. by withdrawing formation water); or lower pressure zones in the formation can be accessed by drilling new wells; and/or new formations may be accessed to maintain the storage rate.

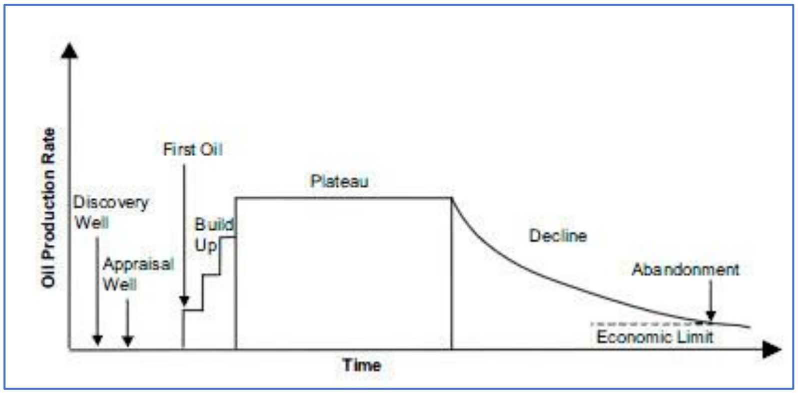

Figure 2 The typical lifecycle of an oil production field is likely to be instructive for a CO_2 storage field. A key difference is that the injection rate must match the supply of CO2. Once the injection rate commences its decline, mitigation is compromised unless new reservoirs are accessed.

The only way to develop an investment level of confidence in actual storage reserves (or dynamic storage profiles [11]) is through field exploration and appraisal – usually involving analysis of seismic data, exploration (stratigraphic) drilling and (petrophysical and geochemical) analysis of drill cores, extended well (production or injection) testing, reservoir engineering and modelling, and field development planning.

In the absence of such exploration and appraisal activities, a quantity called *reservoir complexity* might be defined which allows improved estimates of recovery factor and better correlations between reserves and pore volume. For oil reserves, the reservoir complexity index is used to characterize the reservoir quality based on a few key parameters such as in-situ viscosity, areal density of original oil in place, structural compartmentalization, and reservoir heterogeneity, but can include other parameters for increased reliability. For CO_2 storage reserves, much more work is needed to identify reservoir complexity indices given limited data available in USGS and other databases.

Teletzke et al. (2018) [1] attempted to develop a scoping level estimate of the *practicable* CO_2 storage capacity in the USA and Canada, focusing exclusively on deep saline formations. They account for a number of the critical factors associated with reservoir complexity (e.g. dynamic injectivity, lateral accessibility and thin sands along with surface access restrictions) to derive a debiting function that results in a considerable (six-fold) downscaling of *practicable CO_2 storage capacity* relative to the abovementioned USGS “atlas” publications - Figure 3. However, these analyses still don’t elucidate the likely distribution of peak injection and decline rates by formation, necessary to estimate actual rate-matched CO_2 storage rates and costs over time.

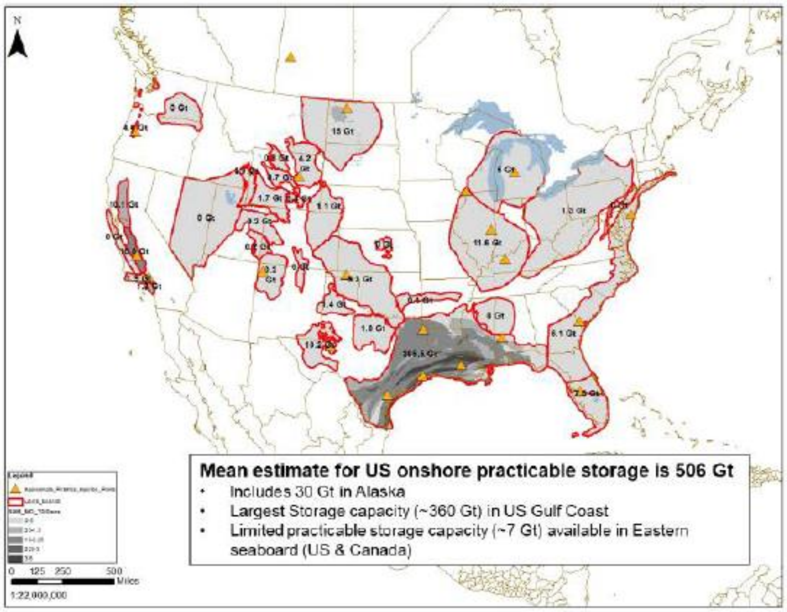

Figure 3 Teletzke et al (2018) [1] assessment of practicable storage in the US – applying a series of filters related to reservoir complexity and permeability to the USGS assessment of Technically Accessible CO_2 Storage Resources. Darker shading represents increasing storage density (Mt per square mile)

2.3 CO_2 Storage associated with Enhanced Oil Recovery

A key early enabler of cost-effective CCS is anticipated through enhanced oil recovery (EOR) which can be applied to increase oil recovery factors. Oil producers may practice CO_2 flooding of reservoirs to increase recovered oil, and can be willing to pay for CO_2 which can offset costs of capture, transmission and injection. Currently the focus is on maximizing oil recovered per tonne of CO_2 retained in the reservoir but, if permanent storage was to be incentivized, EOR practices could shift toward retaining more CO_2 in the formation per unit of oil recovered. Estimates of the potential CO_2 usage currently associated with EOR in the lower 48 states are currently about 80 Mtpa [12] however, the economic potential has been estimated to be in the order of 400 to 500 Mtpa [13]. Discussions with experts in US oil and gas industry majors, indicated It is unlikely that all of this potential would be indeed be viable (for a range of reasons related to reservoir compatibility, abandonment of certain fields since the report [13] was published, etc.). Furthermore, the commercial proposition for the industry to invest in EOR might be expected to reduce with declining oil demand in deep decarbonization scenarios. US oil consumption declines by at 55 – 100% across the various Net-Zero America.

2.4 Implications for CO_2 storage cost curves

Notwithstanding the above critique and weaknesses associated with published gross storage resource estimates, we start with the following onshore and offshore resource estimates and limited storage cost curves, and apply industry-informed judgement to create two notional transport and storage cost curves as follows:

- IEA GHG (2005) indicates a gross storage capacity of 3,800 Gt. IEA GHG also developed a CO_2 storage cost curve (Figure 4) which indicates an injection capacity of 3 Gt per annum including all formation types with a storage cost range of -$9 per tonne to $16 per tonne (negative numbers indicate a revenue benefit associate with enhanced oil or coal bed methane). If the storage associated with coal beds (e.g. enhanced coal bed methane extraction) is excluded on the basis that the practice is not yet commercially proven, the total North American storage potential reduces to approximately 2.5 Gtpa including approximately 500 mtpa of negative cost storage (EOR).

- DOE (2015) indicates a (mean) estimate of gross storage capacity of 8,600 Gt (US, Canada & Offshore).
- Vidas et al. (2012) [4]; estimates the total injection capacity below storage cost of $5 per tonne (2008$) at over 100 Gtpa onshore and 5 Gtpa offshore.
- USGS (2013) indicates a (mean) estimate of gross storage capacity of almost 3,000 Gt for US and State waters.
- Department of Energy (2017) [14] indicates approximately 800 Gt gross storage capacity with a storage cost range of $10 per tonne to $20 per tonne, and published the cost curves for US geologic storage in Figure 5.
- Teletzke et.al. (2018) [1] take the USGS estimate of gross capacity estimate and screen through a series of technical and cost-related filters associate with reservoir characteristics and complexity to arrive at a 506 Gt onshore capacity estimate (50% confidence level) or 406 Gt capacity (95% confidence level) with over 90% being in the US.

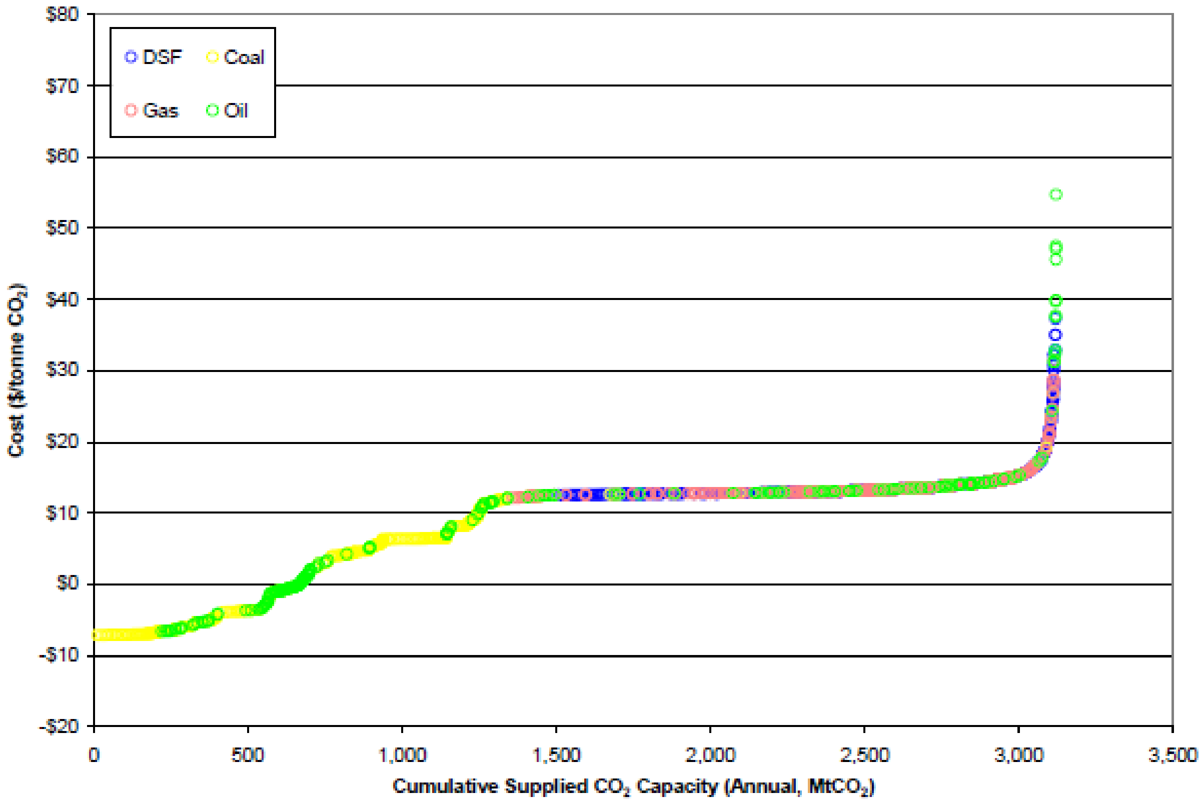

Figure 4 CO_2 storage cost curve for North America after IEA GHG (2005) [6]

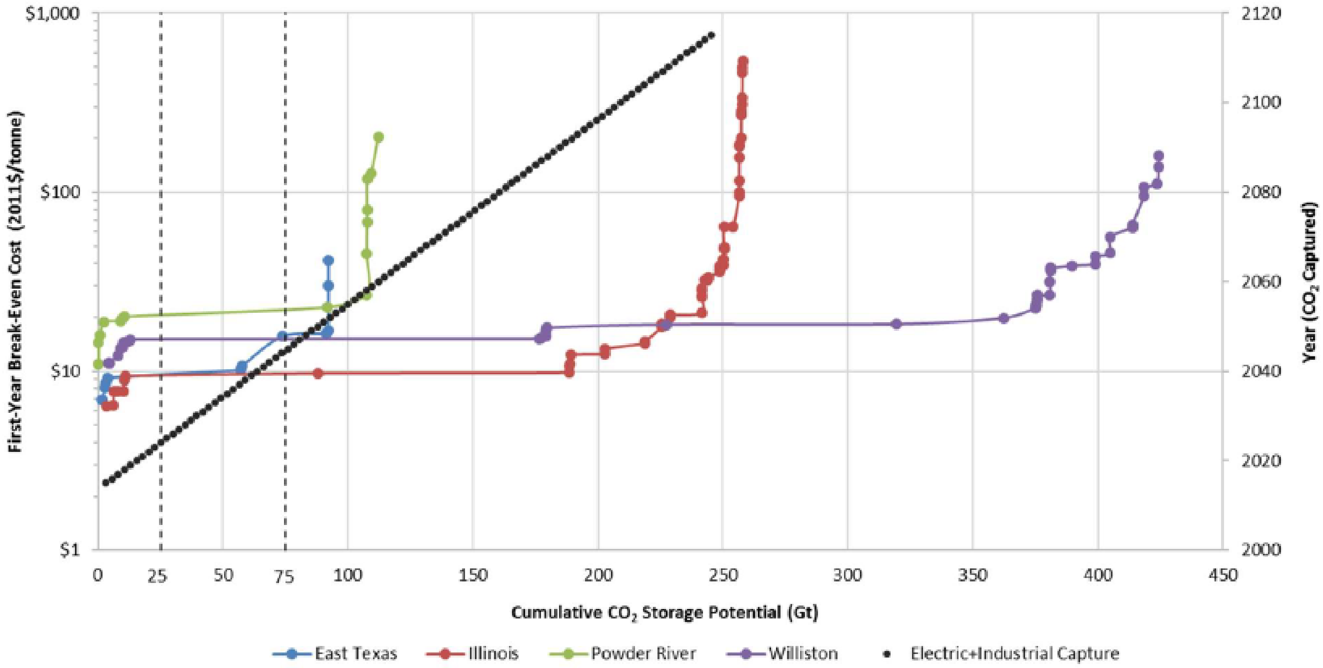

Figure 5 CO_2 storage cost curve for North America after DOE NETL (2017) [14] (gross storage basis rather than annual storage rate; costs in 2011$).

The cost curves developed by IEA GHG and DOE follow a comprehensive methodology but are not necessarily on a consistent basis and do not consider various geological and field development uncertainties and risks including but not limited to:

- Limitations on the availability of data on reservoir characteristics. For example, comparisons between Permian Basin (high level of confidence) and Powder River Basin (low level of confidence);
- Reservoir complexity – e.g. structural variations, heterogeneity in permeability and thickness, allowable pressure to stay below seal facture conditions – all of which impact initial injection rates, decline rates and requirements for pressure management;
- Specific well design requirements;
- Land access leasing and compensation costs; and
- Documentation and make-good on substandard historical plug & abandonment of legacy wells.
- Pipeline standards, right of way negotiations and compensation;
- Conditions associated with permitting;
- Requirements for containment assurance – monitoring, measurement and verification standards.

As such those estimates should be considered estimates of the maximum resource potential with a high level of uncertainty in both capacity and the unit cost of finding and developing storage prospects as well as the storage capital and operating costs. As those resources undergo exploration and appraisal and subjected to access, permitting, geological risk and economic (long-term injectivity) filters, the capacity progressed to 'storage reserves' and a final investment decision will reduce - certain basins may be determined to be not prospective, reserves within prospective basins downgraded, and average pipeline distances from certain point sources to suitable sinks increase.

2.5 Storage costs

Cost estimates that include both capital expenditures and operating costs for storage in saline formations range from \$1 to \$18 per tonne of CO_2 (tCO2) in 2013 dollars. For most sites in the United States, DOE estimates narrow the range from \$7 to \$13/tCO_2. The wide range reflects the site-specific nature of geologic storage projects. In 2019, preliminary cost estimates for storage sites in the Southeastern United States, which has excellent geologic conditions for storage, were as low as \$3/tCO_2. Storage cost is primarily affected by the depth of the formation, volume of CO_2 to be stored, number of injection wells required, purity of the CO_2 stream, existing land uses, and ease of deploying surface and subsurface CO_2 monitoring programs.

All of these cost drivers are currently subject to considerable uncertainty, and discussions with industry practitioners suggest these estimates are likely to be proven to be optimistically low.

2.6 Proposed CO_2 Storage Cost Curves

Based on the above considerations, and discussions with industry practitioners, the following notional cost curves in Figure 10 (base scenario) and Figure 11 (upside scenario) have been built for the purposes of informing the Net-Zero America scenarios. Note that these are simplistic and in reality, each of the regional blocks identified will have their own cost curve.

These cost curves remain highly uncertain for reasons outlined in the previous sections. Furthermore, it is difficult is to match actual sources with specific sinks either spatially or temporally in advance of the decarbonization pathways modelling and infrastructure planning studies.

2.6.1 Base CO_2 Storage Capacity Case – All scenarios except RE+ and E-B+

The base case for CO_2 transport and storage unit costs supply curve was developed as an input to the RIO energy systems model. The main assumptions, parameters and calculation approach is summarized in Table 3 and illustrated in Figures 7 and 8.

Table 3 Summary of main assumptions, parameters and calculation approach for the base CO_2 storage capacity case

Annualized capacity	Following Teletzke et al., (2018) [1] practicable storage capacity is focused on 7 key basins and limited to 400 Gt. The largest capacity attributed to the Texas Gulf Coast. Notionally translate static estimate to annualized storage rate 4 Gt/year and discount 50% allowing for access, permitting, geological risk and economic (injectivity) filters.
CO_2Storage costs (\$/t stored)	Full life storage costs allowing for costs associated with appraisal, legacy well remediation, permitting, capital and operating costs, MMV, etc. Following DOE estimates (\$7 to \$13/t CO_2). \$5 premium for offshore.
CO_2 Transport costs (\$/t stored)	Capacity charge for shared infrastructure notionally estimated at \$15 per t/y + spur lines (collection from source and distribution to injection wells) ranging from \$5 per t/y to \$35 per t/y.

EOR	2020-2025: 200 Mt/y - 50% with net revenue (EOR income less transport and storage cost) of \$10/t CO_2, 50%; and 50% with net revenue of \$0/t CO_2. 2026-2050: Revenue declines to zero leaving full transport and storage cost.

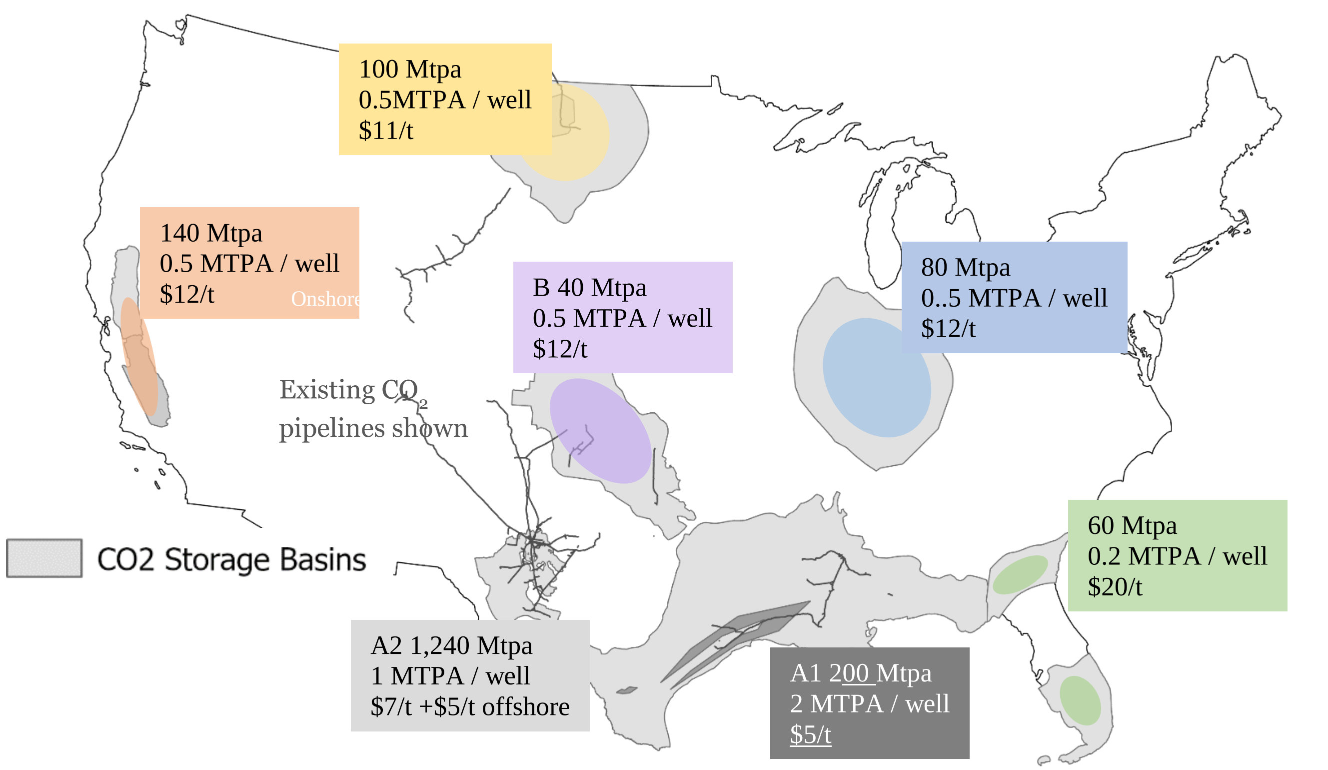

Figure 7 Geological CO_2 sequestration sinks (based on Teletzke et al. [1]),with practicable storage capacities and full-life unit costs of storage notionally nominated for input to Rio energy system modeled (base case – all scenarios except RE- and E-B+).

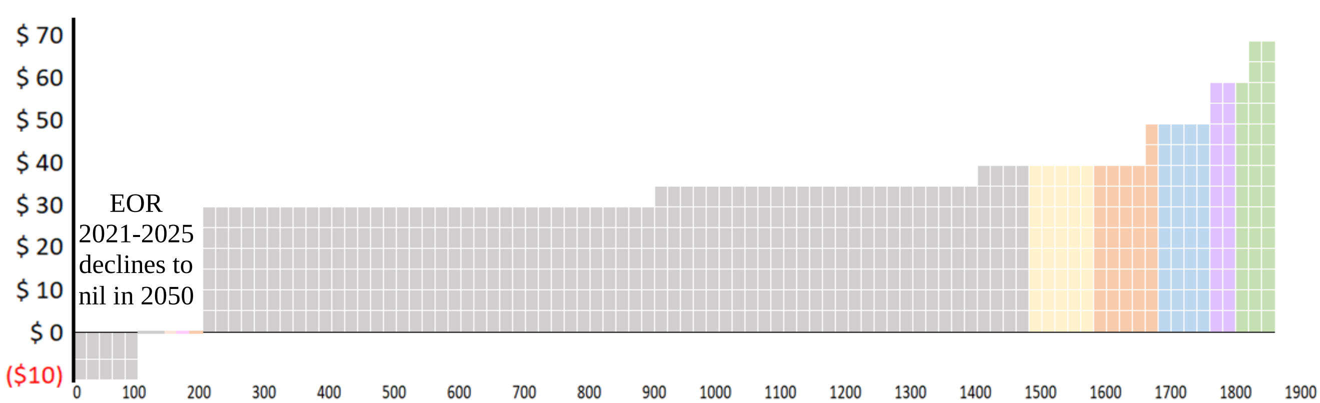

Figure 8 Notional CO_2 transport and storage cost curve (Base case)

2.6.2 Expanded CO_2 Storage Capacity Case – RE+ and E-B+ scenarios only

An expanded, notional CO_2 storage supply curve was developed for the RE+ and E-B+ scenarios, by arbitrarily increasing the EOR potential at the beginning of the transition and also adding an additional gigatonne/year injection rate capacity in the major basins. The expanded supply curve is illustrated in Figure 9.

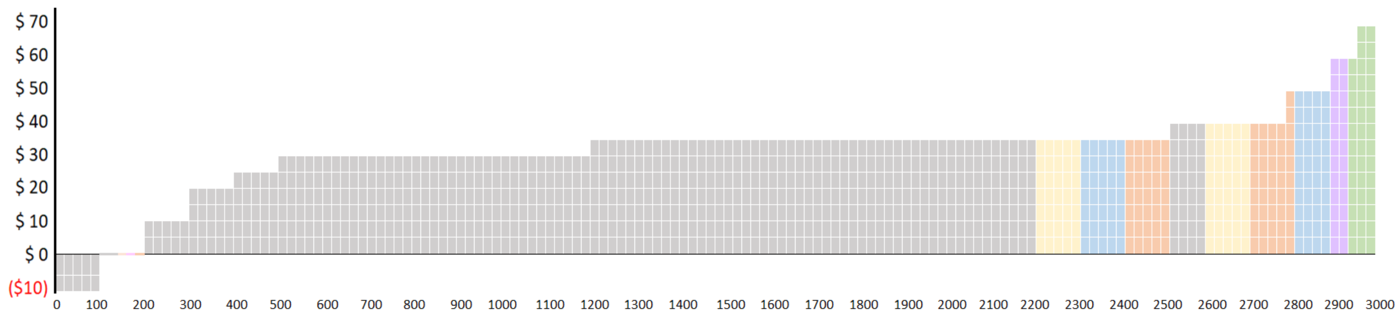

Figure 9 Notional CO_2 transport and storage cost curve (Expanded case for RE+ and E-B+ scenarios)

3 Downscaling CO_2 captured from point sources

In this step, the annual flows of captured CO_2 projected by the EER models are distributed across the geographically located point sources sited in accordance with sector-specific downscaling processes. Sector-specific downscaling was undertaken to site thermal power plants (Appendix F), bioconversion facilities (Appendix G), and cement/lime facilities (Appendix J). This section describes the approach taken allocate CO_2 emissions across downscaled facilities.

Since CO_2 emission/capture downscaling methods are not integrated into the primary downscaling method applied to each sector (bioconversion, cement/lime, and fossil electricity), the decision was made to the allocate CO_2 capture to geospatially located point sources within each sector to be consistent with national rather than regional CO_2 capture totals. This means in essence that the CO_2 capture rates from like facilities entering operation in the same year and generating the same amount of output in that year, but sited at different locations across the nation, would be consistent. This may lead to differences between EER model and NZAP downscaled CO_2 capture results at the regional level, but this approach seemed more consistent than assuming significant differences in the total CO_2 captured by two identical facilities generating the same amount of product.

3.1 CO_2 emissions from thermal power plants

The allocation of CO_2 emissions captured at thermal power plants is based on data available from thermal power plant downscaling (Appendix F). The thermal power plant data set provided by the NZAP thermal power plant downscaling team included both the cumulative capacity installed (MW) and total energy generated (MWh) at each geospatial location for each transition timestep. Table 4 provides the national CO_2 captured from thermal power plant facilities, along with the total generation from operating facilities, and the average CO_2 captured per generating unit at facilities nationally for each transition timestep from 2020 to 2050. We allocated CO_2 emissions to individual thermal power plants in each NZAP study year on the basis of each point source's share of the total generation by thermal generators using CCS technology.

Table 4 Total national CO_2 capture from thermal power plant facilities for E+ scenario in each study year from 2020 to 2050, along with the total generation from operating facilities in E+ scenario in each study year and the average CO_2 captured per generating unit at facilities nationally

Thermal power plant CO_2 allocation aspect	2020	2025	2030	2035	2040	2045	2050
Total CO_2 capture onsite (MMt) from EER model	0.00	0.00	0.51	40.94	54.37	64.78	82.81
Total generation by thermal power plants w/CCS (TWh)	0.00	0.00	2.71	117.42	154.18	185.78	235.86
Average CO_2 captured in Mt per MWh	0.000	0.000	0.188	0.349	0.353	0.349	0.351

3.2 CO_2 emissions from bioconversion facilities

The allocation of CO_2 emissions captured at bioconversion facilities is based on the data available from EER model results and bioconversion downscaling (Appendix G), which is presented in Table 5.

Table 5 Bioconversion processes that have a tracked CO_2 capture stream in the EER model and NZAP downscaling, along with 2050 CO_2 capture total in E+ scenario, the national input requirements per process in 2050 (unitless), and the CO_2 capture per input requirement (MMt CO2) in 2050

Bioconversion process	**National total CO_2 capture (MMt/CO_2) from EER model**	**National biomass input used in NZAP bioconversion downscale (MMt of biomass)**	**Average CO_2 capture per unit of biomass utilized (MMt CO_2/MMt biomass)**
BECCS hydrogen production	642.058	426.818	1.504
BECCS syngas	0.004	0.022	0.199
BECCS diesel	0.180	0.210	0.855
BECCS pyrolysis	88.578	93.237	0.950
BECCS power	78.766	49.700	1.585

CO_2 capture flows are allocated to the bioconversion facilities located at each geospatial location in the bioconversion dataset,[2] by multiplying the average national CO_2 captured per unit of biomass used in a given year, by the biomass input used by each process located at the geospatial location in the same year. A CO_2 capture total was then allocated to the geospatial location by summing the CO_2 captured from all processes at the location.

[2] Biomass dataset points are located at the center point of each 100 mile by 100 mile cell in a fishnet covering the entirety of the contiguous continental U.S.. Bioconversion modeling also assumes uniform technology within each bioconversion process category, and a uniform input requirement per unit output of CO_2 for each bioconversion technology type.

3.3 CO_2 emissions from cement/lime facilities

The NZA project assumed that all new cement (and co-located lime) facilities built after 2025 will incorporate CCS technology. Each new cement/lime facility built throughout the transition is assumed to be based on a standard world-class scale and technology and produces the same amount of cement/lime a year. This uniformity across cement/lime sectors leads to each new facility having the same CO_2 emissions. The fraction of CO_2 captured is assumed to transition across the sector from 65% in 2026 to 90% in 2029 so that each new cement/lime facility will capture the same amount of CO_2 in any selected year. The CO_2 captured at each sited cement/lime facility is estimated by dividing the total annual CO_2 emissions captured by the national cement/lime industry by the number of new facilities operating for each transition timestep. Table 6 shows the total national CO_2 emissions from all cement/lime facilities for each transition timestep from 2020 to 2050, along with the number of new, operating facilities and the average CO_2 captured at each new facility.

Table 6 Total national CO_2 capture from cement/lime facilities in all scenarios in each study year from 2020 to 2050, along with the number of operating facilities in each study year and the average CO_2 capture at each facility

Cement/lime CO_2 allocation aspect	2020	2025	2030	2035	2040	2045	2050
Total CO_2 emitted onsite (MMt) from NZAP model	86.48	96.56	100.49	105.96	115.77	128.14	139.26
Total CO_2 captured onsite (MMt) from NZAP model[3]	0.00	0.00	16.20	50.31	82.94	109.48	123.70
Number of co-located cement/lime facilities with CCS	0	0	5	15	25	32	35
Average CO_2 captured per facility (MMt)	0	0	3.24	3.35	3.32	3.42	3.53

3.4 Mapping harmonized CO_2 points sources and flows

Figure 6 and Figure 8 present the results of mapping CO_2 point sources in 2050 the E+ and E-B+ scenarios respectively.

[3] Appendix J notes that there are discrepancies in CO_2 emissions captured in later years due to different CO_2 capture rates being implemented in EER model than specified in NZAP model. There will also be discrepancies in study years – most notably 2030 – as the final retirement/build schedule for cement plants happened after the last EER run. For 2030, this means that one less plant was built between 2025 and 2030 in NZAP downscaling, than is specified in the EER model. The 100% capture rate used in the EER model and the expected operation of one more cement plant with CCS in 2030 in the EER model, lead to the ~4.5 MMt discrepancy between Table 6 and Table 22 for cement plants in 2030.

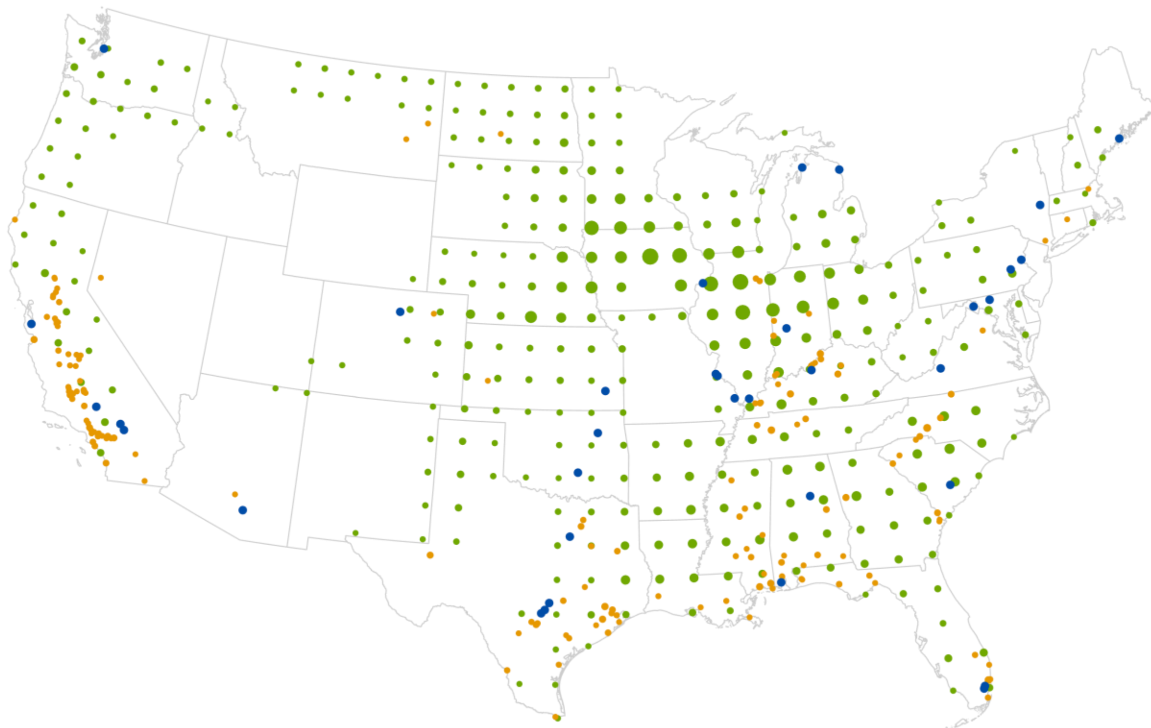

Figure 6 CO_2 point sources arising under the E+ scenario (each indicated BECCS location may represent a cluster of individual facilities)

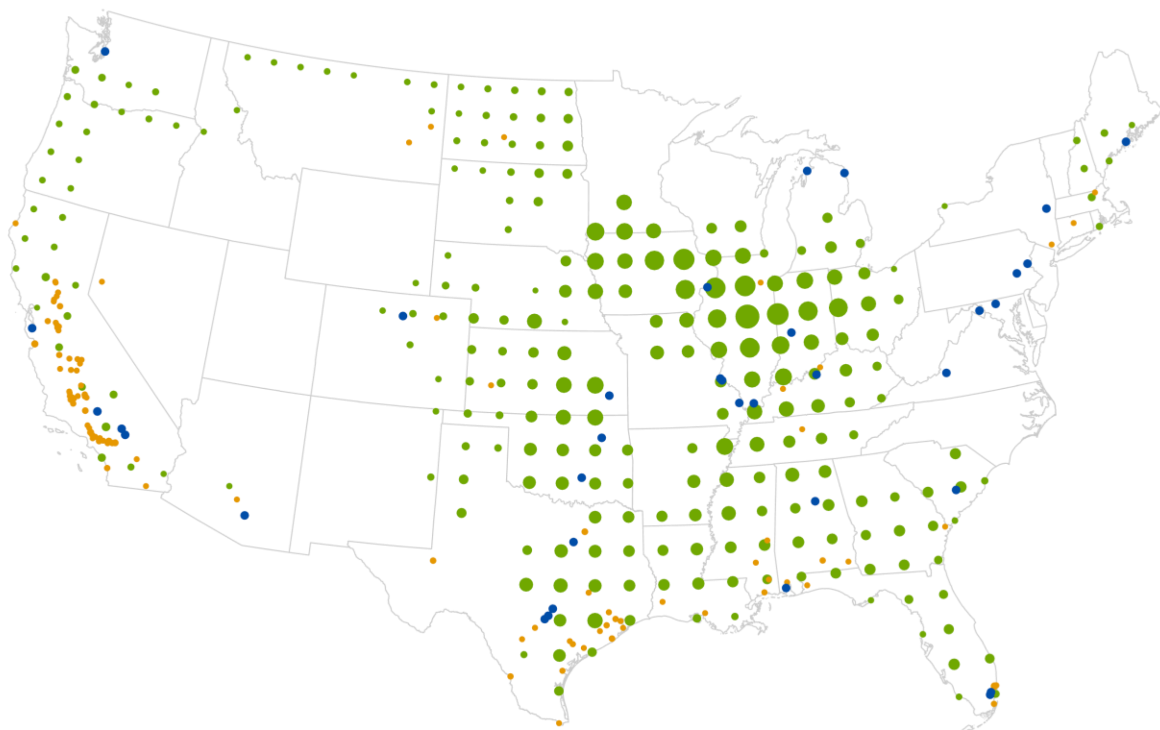

Figure 7 CO_2 point sources arising under the E-B+ scenario (each indicated BECCS location may represent a cluster of individual facilities)

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4 CO_2 Infrastructure Development Approach

The requirement for geological sequestration ranges from almost 1 to 1.7 gigatonne of CO_2 per annum, starting with modest rates from 2026 to 2035 followed by very rapid expansion in the 2040's.

Currently in the US, around 80 million tonnes per year of CO_2 injection takes place, mostly for enhanced oil recovery (EOR) which has no requirement to verify permanent storage.

The scale-up challenge is therefore circa three orders of magnitude based on current permanent storage, or one order of magnitude if EOR injection rates are considered. This makes for an ambitious CCS deployment effort.

4.1 CCS Project Development Sequence

An individual integrated CCS project will typically follow a development (investment decision) sequence illustrated in Figure 1.

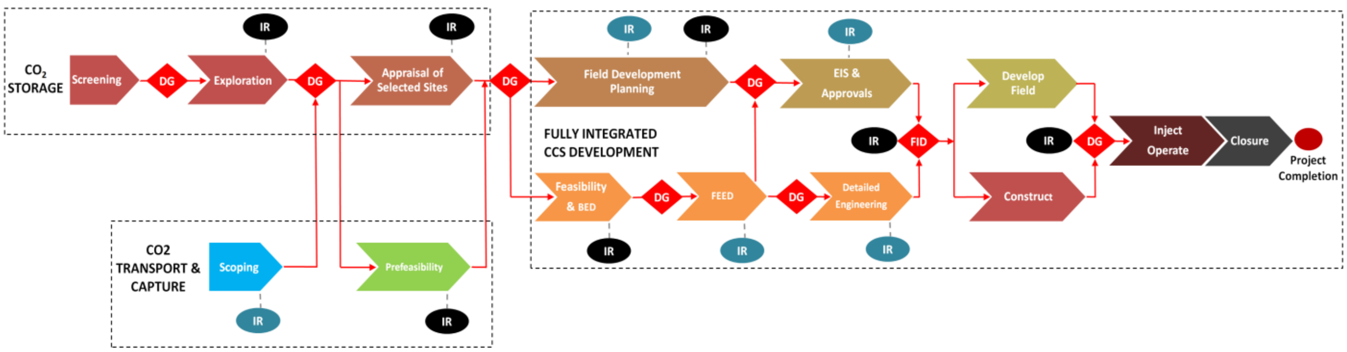

Figure 8 Typical Investment Decision Sequence for an integrated CCS project [15]

Such a sequence commences with exploration of potential CO_2 storage resources, progressing to appraisal of a number of target sites, sometimes in parallel with scoping and prefeasibility studies of potential CO_2 capture projects, before a decision can be made to proceed to engineering, field development planning, and environmental studies to inform the feasibility and permitting decisions for an integrated CCS project. This sequence will typically take 3 to 8 years depending on the location, availability of subsurface data, permitting regimes, and characteristics of the emitter facility, before the integrated project reaches a final investment decision.

4.2 The Investment uncertainty challenge

A *cross-sectoral investor-confidence* challenge for many CCS applications stems from the different industry sectors and actors participating along the CCS value chain. At the CO_2 source end are power and industry emitters (cement, power, bioenergy, etc.) considering CO_2 capture. At the other end are the upstream oil and gas producers, with capabilities to develop and operate geological storage of CO_2. Connecting the two are pipeline owners which might be one of the aforementioned actors, or an independent actor. CO_2 storage developers will be reluctant to invest without confidence in long-term CO_2 supplies from emitters that remain competitive long into the future. At the same time, CO_2 emitters will be reluctant to invest in capture without confidence that long-term, affordable CO_2 storage is accessible, especially when alternative low-carbon options might be available.

A further characteristic of the investment decision sequence is that individual integrated projects can not take advantage economies of scale of large-scale CO_2 storage hubs. We propose a development approach which counteracts the cross-sectoral risks and by advancing such large-scale CO_2 storage hubs connected with a national pipeline network. Out rationale is that such an approach will be necessary to achieve the scale and pace of CCS expansion envisaged in the Net Zero Australia scenarios and hence to enable gigaton/year-plus CCS by 2050.

4.3 Development and Cost of Geologic Storage Capacity

The proposed development approach will advance CO_2 storage assets to a level of investment confidence in advance of the needs of potential capture projects in the power, industry and bioenergy sectors, along with direct air capture proponents. An estimate of the unit cost of storage will be derived by calculating the levelized cost of storage considering - capital costs (characterization and development costs along with capital cost of wells, surface facilities and owners costs), and the ongoing operating costs associate with injection and monitoring, over the life of the injection well -using a discounted cashflow analysis.

4.4 CO_2 Storage Site Characterization

Investment in CO_2 storage appraisal is proposed for the 6 priority basins, shaded grey in Figure 9, as described earlier.

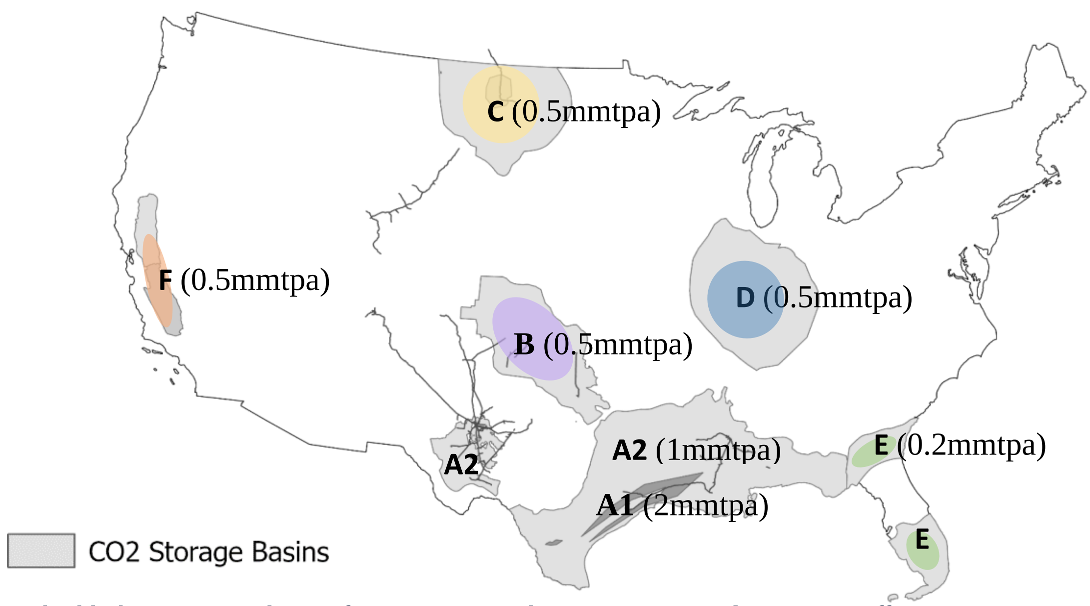

Figure 9 Map highlighting priority basins for CO_2 storage characterization and permitting efforts.

The first stage of CO_2 storage development involves pre-competitive exploration, extensive stakeholder engagement, surveys of legacy wells and drill penetrations, finalization of regulatory rules, environmental baselining, and impact assessments, at a basin-wide scale.

An indicative budget of $500 million per basin is proposed with up to six priority basins to be considered, was developed in consultation with CO_2 storage specialists in the upstream oil and gas industries.

The second stage of CO_2 storage development involves the appraisal and permitting of target injection sites. Discussions with CO_2 storage specialists in the US onshore oil and gas sector indicated that a typical injection site would likely sustain a typical CO_2 injection rates averaging five million tonnes per annum, with the limitation being access to contiguous pore space. This would suggest 200 individual injection sites are required to sustain one Gigatonne/year of geologic storage. The costs to appraise and permit each site are likely to be highly variable, as is the appraised sustainable injection rate. Some of the sites appraisals may also result in a decision not to proceed, due to a variety of technical and non-technical constraints. Furthermore, the nature and scale appraisal costs will vary according to the availability of subsurface data. For locations that have hosted significant prior exploration and/or hydrocarbon extraction, appraisal costs will be reduced due to the availability of extensive data sets, but likely offset by the need to remediate legacy penetrations and wells. For budgeting purpose, an average of $50 million per injection site permitted, is proposed. Note that these costs do not include injection wells, distribution pipeline (transmission line to wells) and associated topside facilities.

We assume for the purpose of the cost estimates, that a given scenario utilizes storage capacity in proportion to the notional maximum capacity according to the relevant supply curve presented in Figures X & Y.

These costs can be used to model a CO_2 storage *unit characterization cost* which could be charged to capture projects on a per tonne stored basis. depending on the business model, those storage costs may vary by basin and/or injection site, but for the purposes of this study we will develop a single harmonized unit development cost applicable to all CO_2 injected.

The total investment in CO_2 storage exploration, appraisal and permitting (to be "investment-ready") is estimated at $13 Billion, which we notionally schedule in Table 7 and Table 8.

Table 7 Coarse breakdown and timing for CO_2 storage exploration for E+, appraisal and permitting (1 Gigatonne / year storage capacity to "investment-readiness")

BASIN	Potential (Mtpa)	No of Plays	**Characterization ($M)**	Characterization ($M) 2021-25	Characterization ($M) 2026-30	**Appraisal & Permitting ($M)**	Appraisal & Permitting ($M) 2021-25	Appraisal & Permitting ($M) 2026-30	Appraisal & Permitting ($M) 2031-35
A1	200	22				**$ 1,100**	0	$ 700	$ 400
A2	1,240	133	**$ 500**	$ 250	$ 250	**$ 6,630**	0	$ 4,000	$ 2,630
B	40	4	**$ 500**	$ 250	$ 250	**$ 200**	0	$ 100	$ 100
C	100	10	**$ 500**	$ 250	$ 250	**$ 500**	0	$ 250	$ 250
D	80	8	**$ 500**	$ 250	$ 250	**$ 400**	0	$ 200	$ 200
E	60	6	**$ 500**	$ 250	$ 250	**$ 300**	0	$ 100	$ 200
F	140	17	**$ 500**	$ 250	$ 250	**$ 870**	0	$ 400	$ 470
Total	1,860	200	**$ 3,000**	$ 1,500	$ 1,500	**$ 10,000**	$ -	$ 5,750	$ 4,250

Table 8 Coarse breakdown and timing for CO2 storage exploration for E-B+, appraisal and permitting (1.64 Gigatonne / year storage capacity to "investment-readiness")

BASIN	Potential (Mtpa)	No of Plays	**Characterization ($M)**	Characterization ($M) 2021-25	Characterization ($M) 2026-30	**Appraisal & Permitting ($M)**	Appraisal & Permitting ($M) 2021-25	Appraisal & Permitting ($M) 2026-30	Appraisal & Permitting ($M) 2031-35
A1	500	56				**$ 2,800**	0	$ 1,780	$ 1,020
A2	1,700	188	**$ 500**	$ 250	$ 250	**$ 9,400**	0	$ 5,700	$ 3,700
B	80	8	**$ 500**	$ 250	$ 250	**$ 400**	0	$ 200	$ 200
C	240	26	**$ 500**	$ 250	$ 250	**$ 1,300**	0	$ 650	$ 650
D	220	24	**$ 500**	$ 250	$ 250	**$ 1,200**	0	$ 600	$ 600
E	60	6	**$ 500**	$ 250	$ 250	**$ 300**	0	$ 100	$ 200
F	200	18	**$ 500**	$ 250	$ 250	**$ 910**	0	$ 420	$ 490
Total	3,000	326	**$ 3,000**	$ 1,500	$ 1,500	**$ 16,310**	$ -	$ 9,450	$ 6,860

4.4.1 CO_2 Storage Development Costs

Development costs for CO_2 storage include the capital cost associated with engineering, procurement, installation and construction of injection wells, monitoring wells and other pressure management facilities, and other surface facilities including but not limited to distribution pipes (from CO_2 transmission line to well head), and well-head controls along with owner's costs.

Such costs will depend on the sustainable injection rates (allowing for initial injection rates, decline and rates), surface and subsurface characteristics, location of injection sites, pressure management requirements, license conditions, the presence and activities of other users of the nearby surface and subsurface, approved MMV protocols, compensation to landowners, and so on. These are not possible to quantify *a priori*. We applied the following calculation to provide an indicative, ball-park estimate of the costs as a function of notional average injection rates depicted in Figure 7.

Average capital cost per injection well = $30 million

[incl. injection wells, monitoring wells, surface facilities and owner's costs]

Table 9 Coarse breakdown and timing CO_2 development cost (wells and facilities) i.e. injection-ready for E+ scenario (0.929 Gigatonne/year geologic storage).

BASIN	Wells & Facilities ($M) 2021-25	Wells & Facilities ($M) 2026-30	Wells & Facilities ($M) 2031-35	Wells & Facilities ($M) 2036-40	Wells & Facilities ($M) 2041-45	Wells & Facilities ($M) 2046-50	**Total Wells & Facilities**
A1	$ -	$ 114	$ 332	$ 349	$ 534	$ 321	**$ 1,650**
A2	$ -	$ 1,380	$ 3,997	$ 4,205	$ 6,439	$ 3,869	**$ 19,890**
B	$ -	$ 83	$ 241	$ 254	$ 389	$ 233	**$ 1,200**
C	$ -	$ 208	$ 603	$ 634	$ 971	$ 584	**$ 3,000**
D	$ -	$ 166	$ 482	$ 507	$ 777	$ 467	**$ 2,400**
E	$ -	$ 312	$ 904	$ 951	$ 1,457	$ 875	**$ 4,500**
F	$ -	$ -	$ 1,860	$ 900	$ 900	$ 1,560	**$ 5,220**
Total	$ -	$ 2,264	$ 8,419	$ 7,800	$ 11,467	$ 7,910	**$ 37,860**

Table 10 Coarse breakdown and timing CO_2 development cost (wells and facilities) i.e. injection-ready for E-B+ scenario (1.6 Gigatonne/year geologic storage).

BASIN	Wells & Facilities ($M) 2021-25	Wells & Facilities ($M) 2026-30	Wells & Facilities ($M) 2031-35	Wells & Facilities ($M) 2036-40	Wells & Facilities ($M) 2041-45	Wells & Facilities ($M) 2046-50	**Wells & Facilities ($M) Total**
A1	$ -	$ 291	$ 844	$ 888	$ 1,360	$ 817	**$ 4,200**
A2	$ -	$ 1,956	$ 5,667	$ 5,962	$ 9,130	$ 5,486	**$ 28,200**
B	$ -	$ 166	$ 482	$ 507	$ 777	$ 467	**$ 2,400**
C	$ -	$ 541	$ 1,567	$ 1,649	$ 2,525	$ 1,517	**$ 7,800**
D	$ -	$ 499	$ 1,447	$ 1,522	$ 2,331	$ 1,401	**$ 7,200**
E	$ -	$ 312	$ 904	$ 951	$ 1,457	$ 875	**$ 4,500**
F	$ -	$ -	$ 1,946	$ 941	$ 941	$ 1,632	**$ 5,460**
Total	$ -	$ 3,766	$ 12,857	$ 12,420	$ 18,521	$ 12,195	**$ 59,760**

The average unit development cost can be derived by calculating the levelized cost of development over the life of the injection well, using a discounted cashflow analysis.

4.4.2 CO_2 Storage Operating and Maintenance Costs

For storage operating costs, the major element of operating costs will be associated with permit compliance activities and maintenance. We have allowed a notional 4% per annum of the total storage capital investment plus an additional (notional) $2 per tonne for general & administration including compliance/verification costs.

4.4.3 Total Average unit cost of storage by Basin

Total calculate the unit costs for CO_2 storage including characterization, appraisal, development and operations and maintenance, a series of discounted cashflow analyses were run to yield the levelized cost associated with each component. These are summarized as follows in Table 11 and Table 12. These results provide a level of comfort in the assumed notional average injection costs of $7 per tonne.

Table 11 Summary of the unit costs for CO_2 storage including characterization, appraisal, development and operations and maintenance E+

Area	Characterizatio ($/tonne CO_2)	Appraisal ($/tonne CO_2)	Development ($/tonne CO_2)	O&M ($/tonne CO_2)	Capacity Utilized (Mtpa)	**Total Unit ($/tonne CO_2)**
Area A1	$ 0.33	$ 0.85	$ 0.86	$ 2.69	110	$ 4.73
Area A2	$ 0.33	$ 0.84	$ 1.72	$ 3.37	663	$ 6.27
Area B	$ 0.33	$ 0.82	$ 3.44	$ 4.74	20	$ 9.34
Area C	$ 0.33	$ 0.82	$ 2.30	$ 4.74	50	$ 8.19
Area D	$ 0.33	$ 0.82	$ 3.44	$ 4.74	40	$ 9.34
Area E	$ 0.33	$ 0.78	$ 5.74	$ 8.86	30	$ 15.71
Area F	$ 0.33	$ 0.81	$ 3.69	$ 4.83	87	$ 9.66
Average						$ 6.12

Table 12 Summary of the unit costs for CO_2 storage including characterization, appraisal, development and operations and maintenance E-B+

Area	Characterization ($/tonne CO_2)	Appraisal ($/tonne CO_2)	Development ($/tonne CO_2)	O&M ($/tonne CO_2)	Capacity Utilized (Mtpa)	**Total Unit ($/tonne CO_2)**
Area A1	$ 0.33	$ 1.39	$ 1.40	$ 3.12	280	$ 6.24
Area A2	$ 0.33	$ 1.38	$ 2.81	$ 4.24	940	$ 8.75
Area B	$ 0.33	$ 1.34	$ 5.62	$ 6.48	40	$ 13.76
Area C	$ 0.33	$ 1.34	$ 5.62	$ 6.48	130	$ 13.76
Area D	$ 0.33	$ 1.34	$ 5.62	$ 6.48	120	$ 13.76
Area E	$ 0.33	$ 1.27	$ 14.05	$ 13.19	30	$ 28.84
Area F	$ 0.33	$ 1.32	$ 6.02	$ 6.62	91	$ 14.29
Average						$ 9.09

4.5 Siting, sizing and costing CO_2 pipeline infrastructure

4.5.1 CO_2 transmission lines

A guiding design principal of the CO_2 transmission pipeline network was that the geospatial layout should support the capture and transport of CO_2 from point sources sited under both the E+ and E-B+ scenarios. Transmission pipeline sizes could then be scaled up to meet the requirements set by point sources under either scenario. This approach was adopted so that CO_2 pipeline infrastructure right-of-ways might be agreed upon sooner rather than later, and regardless of the eventual technology pathways chosen to achieve net-zero emissions. Only under 100% renewable scenarios would these right-of-ways be largely unused. Table 1 suggests that in all other scenarios, CO_2 capture and sequestration results in the minimum capture and transport of 1,000 MMt of CO_2 a year.

To aid in the effort of building a CO_2 transmission pipeline network that would be sited reasonably for all scenarios, point source facilities for both the E+ and E-B+ scenarios in 2050 were located on a map indicating the major CO_2 storage basins (Figure 10).

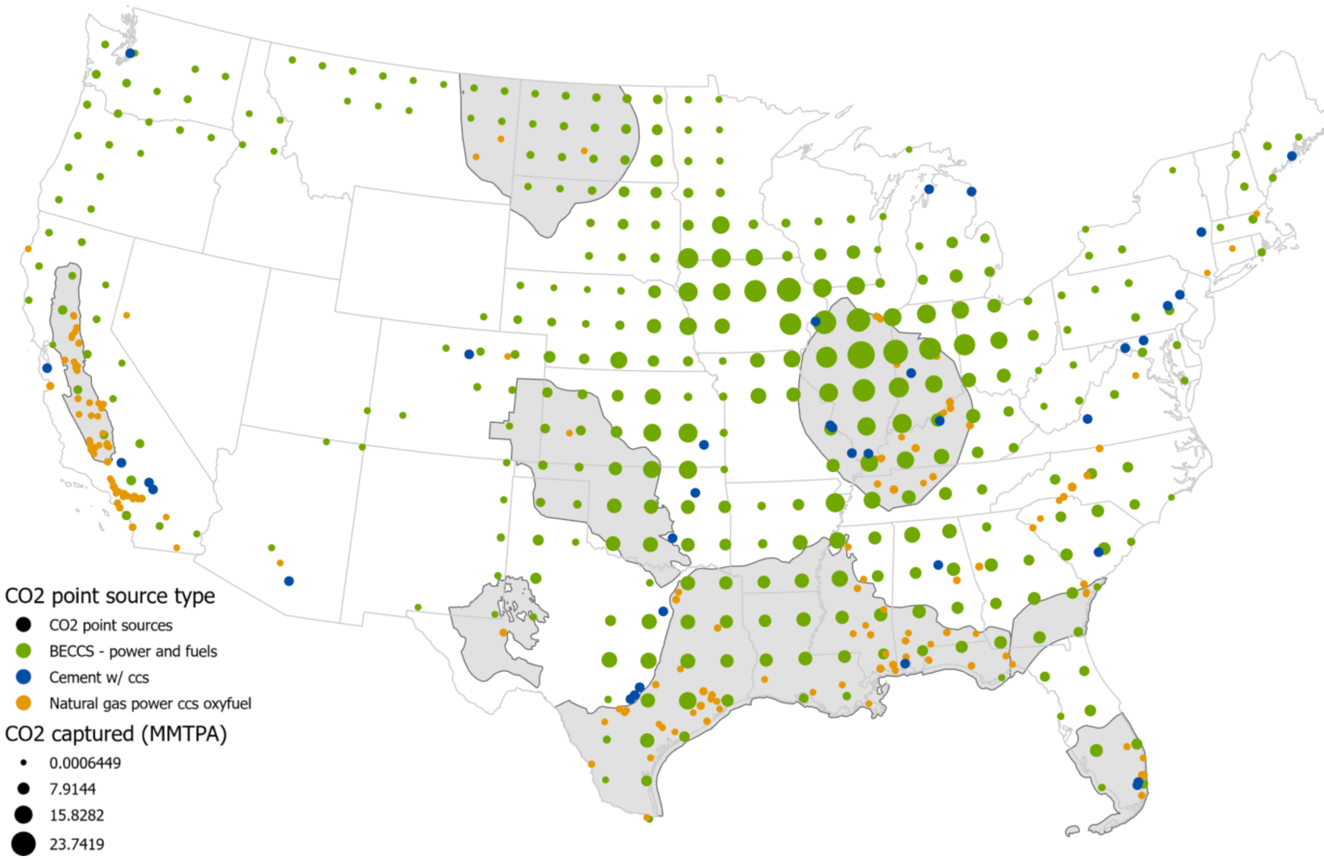

Figure 10 All CO_2 point sources in the E+ and E-B+ scenarios (2050)

The NZAP team then drew notional transmission pipeline pathways by hand, attempting to connect the largest number of CO_2 sources to CO_2 basins, while both minimizing the number of transmission pipelines and the length of individual spur pipelines. Hand drawings were then turned into the transmission pipeline layout shown in Figure 11 using ArcGIS. The mapping process detailed in

Table 26 encourages CO_2 pipelines to follow all right-of-way corridors already followed by interstate highways, electricity transmission lines (>= 220 kV), railways, natural gas pipelines, ammonia pipelines, and already existing CO_2 pipelines [2]. Figure 11 also provides an estimate of the distance of each point source from transmission pipelines.

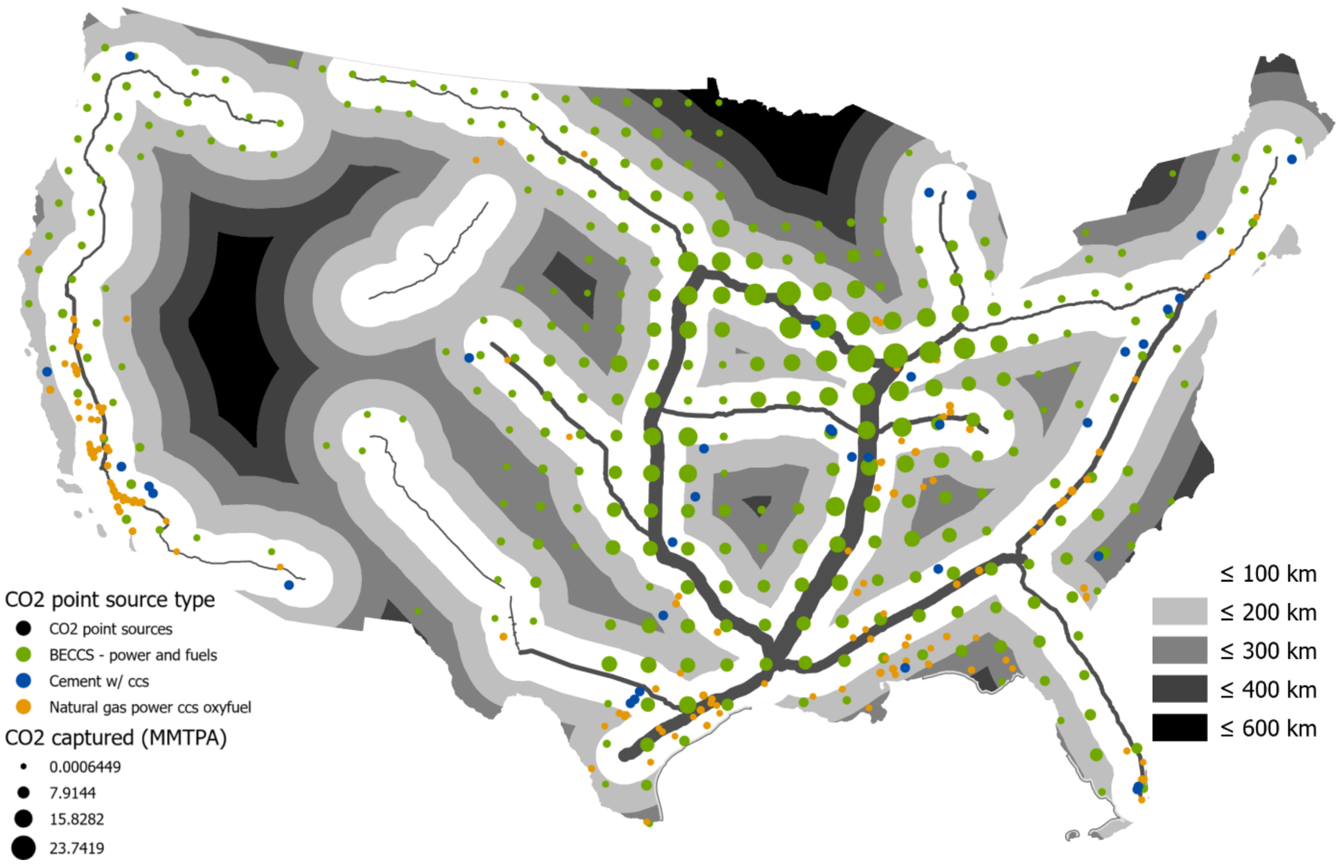

Figure 11 All CO_2 point sources in the E+ and E-B+ scenarios along with the distance to the nearest CO_2 transmission pipeline

The sector specific spatial downscaling for point sources was then repeated to minimize the number of capture facilities located more than 200 km from a transmission pipeline corridor or storage basin.

Note that a systematic optimization of the lowest-cost CO_2 transmission pipeline network might result in the actual system-wide minimization of distances from potential CO_2 point sources to transmission pipelines but acknowledging the highs level of uncertainty associated with the likely future siting of facilities, capacities of storage basins and location of specific injection sites, it was decided that this more notional / indicative scheme was appropriate.

The required capacity was determined for each transmission corridor for each of the two scenarios using the transmission pipeline catchment zones shown in Figure 12 and considering the annual CO_2 storage capacities for each basin indicated in Figure 9. For each scenario, transmission pipelines are sized to satisfy the maximum annual flow from all point sources within a transmission pipeline's catchment, plus inflows from upstream connected pipelines less outflows to CO_2 storage basins.

The optimal pipeline diameter and capital cost is estimated using the FE/NETL CO_2 Transport Cost Model [16], [17]. A refinement was adopted to standardize individual pipeline sizes to a maximum of 48-inch diameter (running multiple pipes in parallel where required) and to harmonize the pipeline sizes between the E+ and the E-B+ scenarios (adding parallel pipe strands or adjust the number of pump stations). This is done by first selecting the optimum diameter using the FE/NETL CO_2 Transport Cost Model [16], [17]. Next, where the calculated pipeline diameter is larger than 48 inch, rerun the model using a fraction of the flow (1/2, or 1/3) until the calculated size is 48 inch or less. Then where the optimum size for E-B+ was different to E+, for example 48 inch versus 4_2 inch, rerun the FE/NETL CO_2 Transport Cost Model specifying the larger pipeline diameter for the lower flowrate case and *vice versa*. Choose the lower of recalculated capital cost with the larger diameter pipeline to deliver the lesser flow by reducing the number of pump stations or *vice versa*.

This process results in the notional transmission corridor capacities specified (in MMTPA) in Table 13 and Table 14, and drawn for 2050 in Figure 12.[4] Note the harmonization of pipeline sizes between scenarios resulted in a relatively small overinvestment in transmission capital ($101 billion versus $97 billion).

Finally, the transmission pipeline investments are made to come onstream one 5-year timestep in advance of the modelled CO_2 capture capacity. Depending on the corridor, this may see the entire investment made in one 5-year timestep or incrementally adding pipeline strands and/or additional to pumps along the corridor, to satisfy the growth in CO_2 captured.

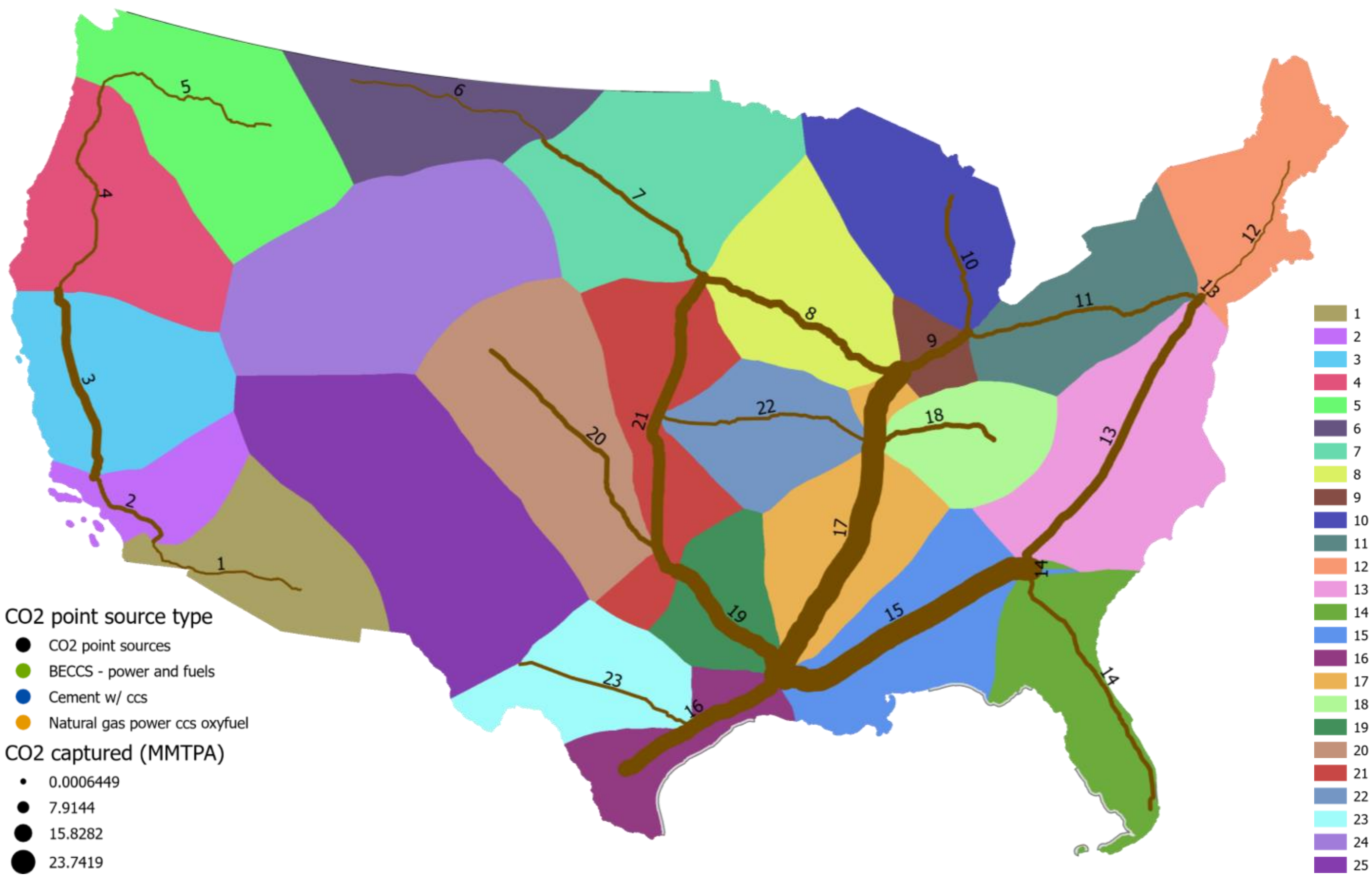

Figure 12 Pipeline catchment areas for the E+ and E-B+ scenarios

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[4] It should be noted that the NZAP team allowed CO_2 point sources to flow into existing CO_2 pipelines connecting the Rocky Mountains to the West Texas basin and Wyoming to the basin in the Dakotas (labelled as trunk line catchments 24 and 25), rather than duplicate the trunk lines. The CO_2 capture flows occurring in those regions were then aggregated along with flows in catchments six and 23. It is expected that aggregate flows within catchments 24 and 25 are within the operating capacities of existing lines, or would result in the private operators of those lines adding capacity to allow connection of NZAP added points sources into those lines. These trunk lines were neither built nor costed as part of the NZAP analysis.

Table 13 Transmission catchment captured CO_2 flows in 2050; design capacities of transmission corridors, pipeline requirements and scheduling for E+ scenario

Transmission pipeline/ catchment	E+ CO_2 captured in 2050 (MMTPA)	E+ Corridor Capacity (MMTPA)	Pipeline size (inches)	Number of Parallel Lines	Estimated Capital Cost ($Million)	First/Final Capacity online
1	4	5	16”	1	700	2030/2030
2	25	30	36”	1	1,200	2030/2030
3	28	70	48”	1	3,500	2030/2030
4	13	30	36”	1	2,700	2035/2035
5	17	17	30”	1	1,800	2035/2035
6	7	10	24”	1	1,100	2030/2030
7	71	70	48”	1	3,900	2035/2035
8	145	150	48”	1	6,000	2030/2030
9	39	90	48”	1	1,500	2030/2030
10	34	30	42”	1	1,600	2030/2030
11	34	30	42”	1	2,800	2030/2030
12	13	13	30”	1	1,100	2030/2030
13	83	120	48”	1	7,000	2035/2035
14	45	40	48”	1	4,800	2030/2030
15	83	210	48”	2	11,500	2030/2035
16	24	170	48”	1	4,600	2030/2030
17	95	250	48”	2	14,700	2030/2035
18	51	50	48”	1	2,300	2030/2030
19	27	140	48”	1	3,600	2030/2030
20	41	40	48”	1	4,600	2030/2030
21	73	180	48”	2	11,900	2030/2035
22	31	30	48”	1	3,900	2030/2030
23	30	90	48”	1	3,700	2025/2025
Total Estimated Capital Cost					100,500	

Table 14 Transmission catchment captured CO_2 flows in 2050; design capacities of transmission corridors, pipeline requirements and scheduling for E-B+ scenario

Transmission pipeline/ catchment	E-B+ CO_2 captured in 2050 (MMTPA)	E-B+ Corridor Capacity (MMTPA)	Pipeline size (inches)	Number of Parallel Lines	Estimated Capital Cost ($Million)	First/Final Capacity online
1	5	5	16”	1	700	2030/2030
2	26	30	36”	1	1,200	2030/2030
3	30	70	48”	1	3,500	2030/2030
4	15	30	36”	1	2,700	2035/2035
5	16	17	30”	1	1,800	2035/2035
6	10	10	24”	1	1,100	2030/2030
7	87	90	48”	1	4,100	2035/2035
8	222	220	48”	2	10,300	2030/2040
9	70	90	48”	1	1,800	2030/2045
10	41	40	42”	1	2,000	2030/2045
11	43	40	42”	1	3,600	2030/2045
12	20	20	30”	1	1,100	2030/2030
13	44	90	48”	1	7,000	2035/2035
14	78	80	48”	1	5,200	2030/2040
15	117	240	48”	2	11,900	2030/2040
16	46	300	48”	2	8,600	2030/2035
17	196	480	48”	3	25,800	2030/2040
18	100	100	48”	1	2,500	2030/2040
19	73	320	48”	2	8,200	2030/2040
20	88	90	48”	1	5,100	2030/2035
21	155	350	48”	3	19,700	2030/2040
22	87	90	48”	1	4,300	2030/2040
23	91	90	48”	1	3,700	2025/2025
Total Estimated Capital Cost					135,900	

4.5.2 CO_2 spur lines – connecting point sources to transmission pipelines

The siting of spur lines, follows the ArcGIS process described in Table 27 to locate minimum distance spur pipelines connecting the CO_2 point sources shown in Figure 6 and Figure 7 to CO_2 transmission lines shown in Figure 12. The result of that process for is shown in for the E+ scenario and E-B+ scenario in Figure 13. In all maps, spur lines are shown with a uniform size.

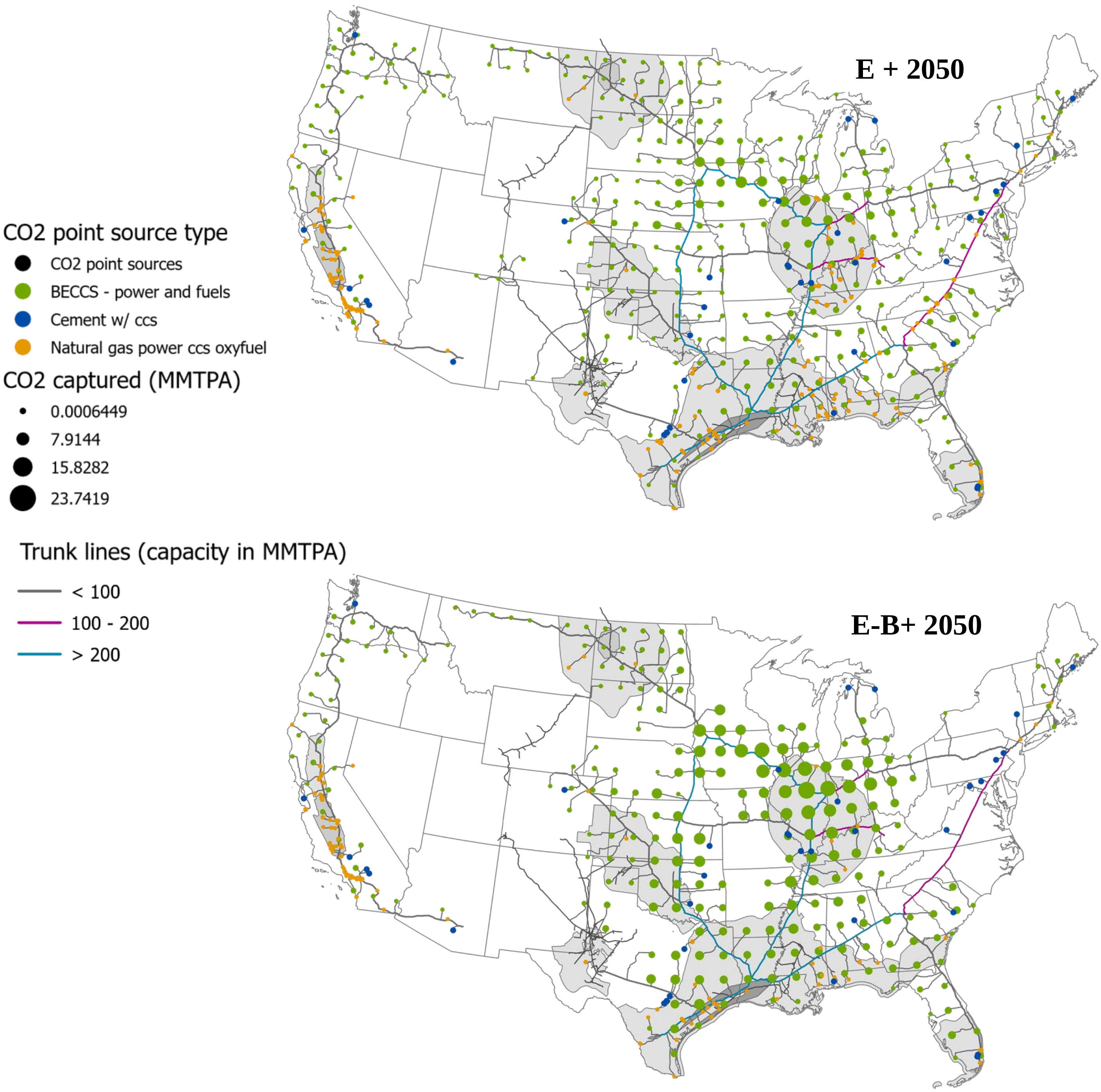


Figure 13 CO_2 point sources, spur pipelines and transmission pipelines in 2050 in the E+ and E-B+ scenarios

For the purposes of reporting and costing spur pipelines, the size of each spur pipeline connected to a cement or thermal power plants mirrors the maximum annual CO_2 flow from each point source. Spur lines connected to bioconversion region centroids (representing clusters of individual bioconversion plants) are sized according to the aggregate sum of all bioconversion facility CO_2 flows attributed to and converge on the centroid. In the reporting of total spur pipeline lengths, additional 35 km sub-spur pipelines are added to allow the connection of individual biomass conversion facilities to a common aggregation point (in this case the provided bioconversion centroid)[5], as well as to allow lime manufacturing facilities that are not located within the same facility footprint as cement manufacturing facilities to connect to cement facilities or their spur pipeline.

Table 15 provides the total estimated spur pipeline lengths and capital costs that was used in developing investment estimations for the E+ and E-B+ scenarios discussed in Annex M. After the investment analysis was run, two minor aspects of the CCS analysis were changed.[6] This led to the revised spur pipeline lengths and capital costs shown in Table 16. Given the minor difference between the results, and the complexity and time involved in re-running the investment estimations, the NZAP team left investment calculations unchanged. The results shown in Table 13 are presented both in this annex and will be available as part of the CCS data made available on the project's web platform in mid-January.

Table 15 Total estimated spur pipeline lengths and capital costs in E+ and E-B+ scenarios (matching CCS results and investment estimations shown in slides and discussed in Annex M)

Pipeline type	E+	E-B+
Spur lines - number	552	417
Spur Lines – total length (km)	61,900	41,000
Sub-spurs - number	743	1,279
Sub-spurs – total length	27,200	44,800
Total length all pipeline spurs	89,100	85,700
Estimated total capital cost ($Million)	$69,000	$88,000

[5] Using a dataset enumerating the total number of facilities located at each centroid in 2050.

[6] One change involved minor alterations to the biomass conversion facility data used as an input to the CCS analysis. The biomass data was in the process of being finalized during the window the investment analysis was being run. The second change involved the correction of an error in the generation of sub-spur pipelines for the number of facilities (n) connecting to a bioconversion centroid. The error led to more sub-spur pipelines being fielded than the planned (n-1) quantity at a bioconversion centroid, but less than the n sub-spur lines at each centroid.

Table 16 Revised total estimated spur pipeline lengths and capital costs in E+ and E-B+ scenarios (will match CCS data made public)

Pipeline type	E+	E-B+
Spur lines - number	552	417
Spur Lines – total length (km)	61,800	41,000
Sub-spurs - number	657	1,281
Sub-spurs – total length	23,000	44,800
Total length all pipeline spurs	84,800	85,700
Estimated total capital cost ($Million)	$66,500	$88,600

The optimal pipeline diameter and capital cost was then estimated using a correlation derived from the FE/NETL CO_2 Transport Cost Model [3]. Application of the cost model to size the pipeline diameters and derive the estimated capital cost, is a manual process for each line. Given the very large number of pipelines (1,295 and 1,696 spur lines and sub-spurs in E+ and E-B+ respectively), a shortcut process was applied. The cost model was applied to a selection of pipeline capacities and lengths which spanned the range of spur lines and sub-spurs specified by the downscaling; and a correlation derived to estimate spur line capital cost from CO_2 flowrate and pipeline length is shown in Figure 14.

$$C = L^{0.97} \times (0.0162 \times M^2 + 0.2627 \times M + 0.9721)$$

C is capital cost in Million USD

L is spur line length in miles

M is CO_2 flowrate in MMTPA

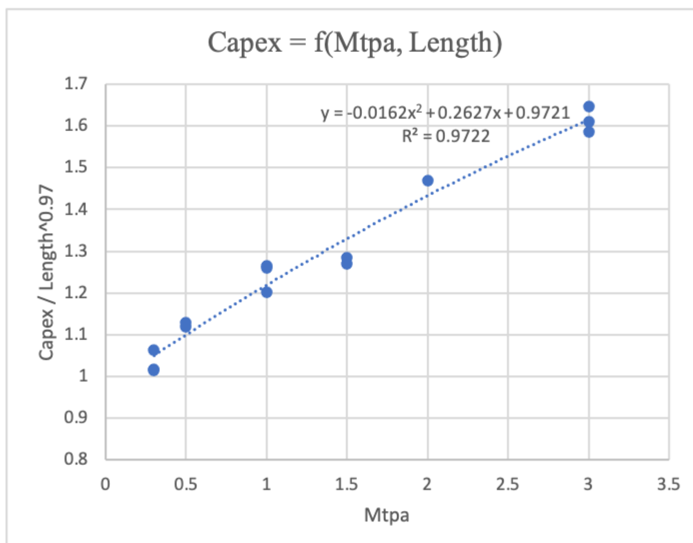


Figure 14 Correlation derived to estimate spur line capital cost from CO_2 flowrate and pipeline length

5 Deployment sequence and unit costs estimates for CO_2 transport

5.1 CO_2 transport infrastructure deployment schedule.

In recognition of the ambitious pace and scale of CCS deployment, strong investment signals must be sent to encourage both investment in energy production facilities with CO_2 capture, and in geological storage characterization and development. Assets at both ends of this value chain (CO_2 sources and sinks) involve long lead times with significant at-risk investment prior to any final investment decision.

Accordingly, the development and construction of the CO_2 transmission network is scheduled to come on stream 5 years in advance of capture facilities seeking to connect. Spur lines connecting point sources to transmission (or in some cases directly to injection sites) are deployed concomitantly with the energy production and capture facilities.

illustrates the proposed deployment sequence for CO_2 pipelines.

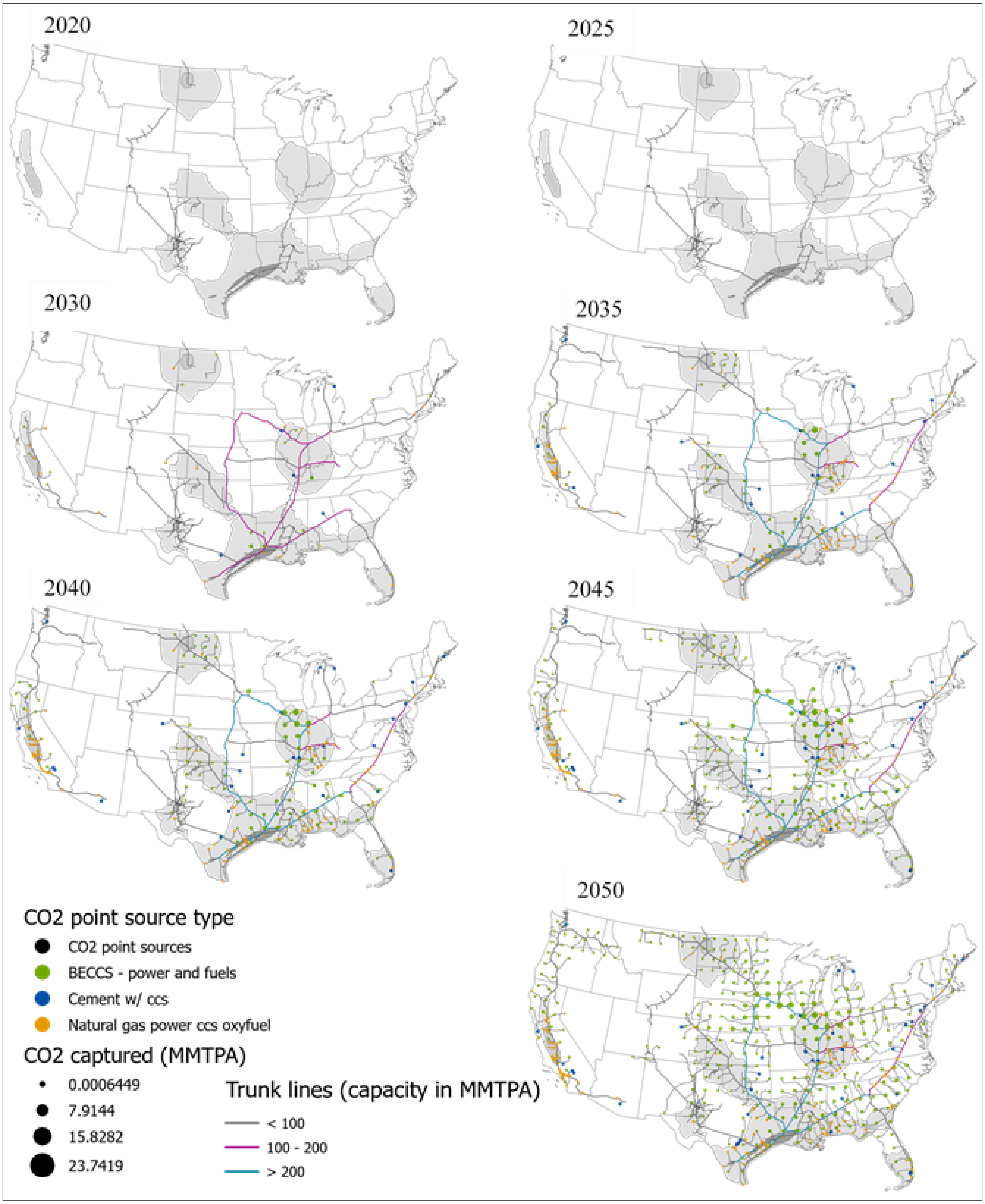


Figure 15 CO2 capture and transport infrastructure transition from 2020 to 2050 in 5-year timesteps

5.2 Unit costs of CO_2 transport.

To establish the unit cost of transport that might be reflective of an infrastructure access charge, a discounted cashflow model was created in which the capital investments in CO_2 transmission pipelines are sequenced according to the

, along with the annual flows of captured CO_2 projected by the EER models. Other assumptions a listed in Table 17.

Table 17 Assumptions used in estimating unit costs of CO_2 transport

Pipeline construction period	5 years
Economic life of pipeline assets	50 years
Annual operating costs	2% of invested capital
Inflation (consistent with EER model)	2% / year
WACC (transmission)	6% Nom before tax
WACC (spur lines if included in regulated pipeline asset base)	6% Nom before tax
WACC (spur lines if part of the capture investment)	5% real before tax

Two separate models for the ownership and cost recovery for CO_2 transport infrastructure were considered, with the following results:

5.2.1 Network Model covering transmission lines only

In this model the CO_2 transport infrastructure is a quasi-regulated asset in which capture facilities purchase capacity in the transmission network at a uniform capacity charge ($/MT CO_2) but are responsible for their own spur line connection to the transmission network meaning spur line capital and hence transport unit costs varying as a function of CO_2 flowrate and pipeline length. **Error! Reference source not found.** lists the Transmission Network Capacity Charges ($/Mt CO_2) in this network model.

Table 18 Transmission Network Capacity Charges ($/Mt CO_2) for network model covering transmission lines only

Network Case	Transmission Network Capacity Charge ($/Mt CO_2)	
	E+ Scenario	E-B+ Scenario
A1 Single National Network	$11.3	$7.6
line unit cost	variable	

Two network structure cases were considered: (i) Single National Network model with uniform capacity charge; and (ii) Separate Eastern and Western Networks with different capacity charges.

The additional unitized cost of transport associated with the capital and maintenance of the spur lines which are borne by the capture facilities vary as function of the CO_2 flow and pipeline distance, will be illustrated in the CO_2 transport cost curves in the next section.

5.2.2 Network Model covering all transmission and spur lines

In this model the CO_2 transport infrastructure is a quasi-regulated asset in which capture facilities are able to contract CO_2 transport services at a uniform regardless of their scale (CO_2 production rate) and distance from the main transmission network. Table 19 lists the Transmission Network Capacity Charges ($/Mt CO_2) in this network model.

Table 19 Transmission Network Capacity Charges ($/Mt CO_2) for network model covering all transmission and spur lines

Network Case	Transmission Network Capacity Charge ($/Mt CO_2)	
	E+ Scenario	E-B+ Scenario
Single National Network (transmission & spur lines included)	$15.9	$10.6

The supply curves in

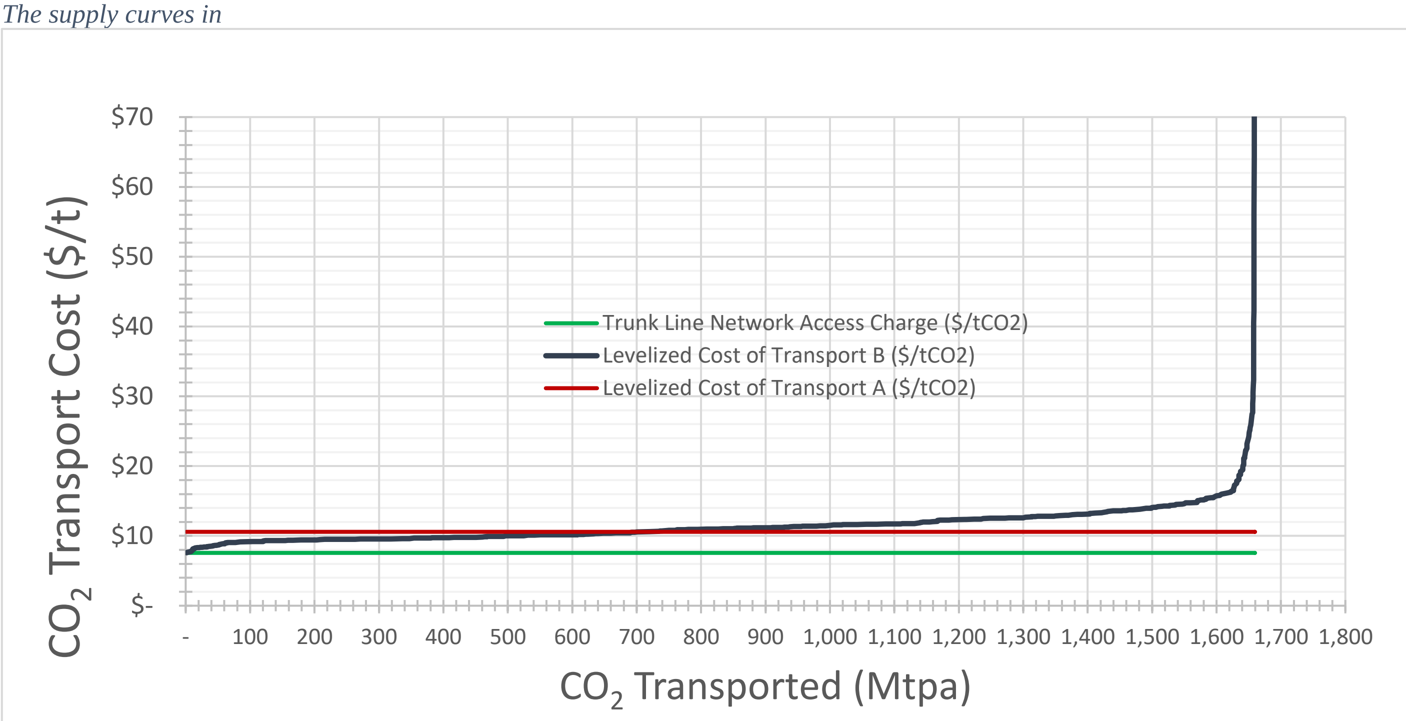
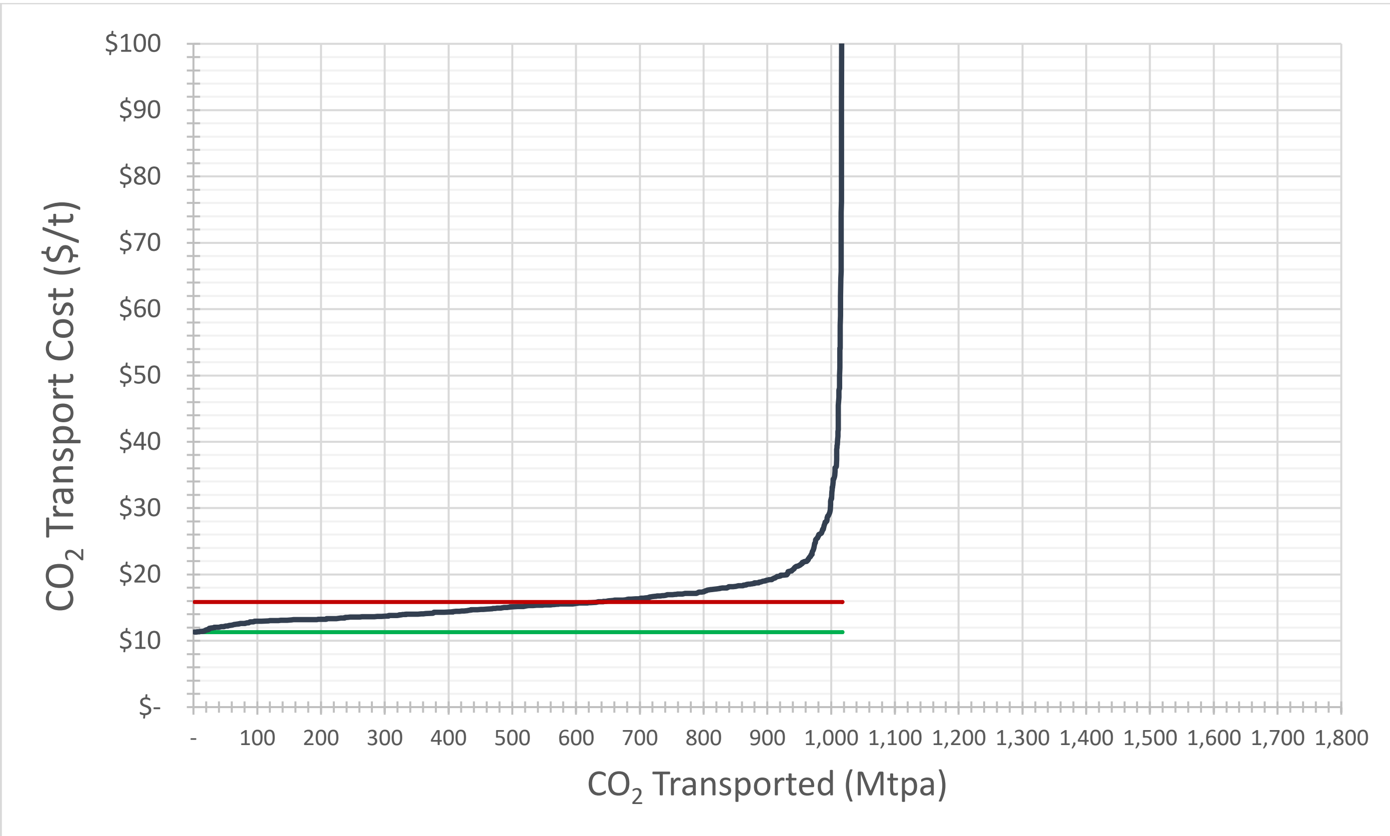


Figure 16 illustrate the different approaches and components of pricing access to the CO_2 transport infrastructure, for the E+ and E-B+ scenarios. The results illustrate the economies of scale for CO_2 transport for the cost advantage evident for the E-B+ scenario. The results also suggest that the marginal point sources occupying the last 10 percentile the unit cost curve are exposed to rapidly escalating transport charges. These point sources tend to be the smaller capacity facilities which a more distant from the transmission network.



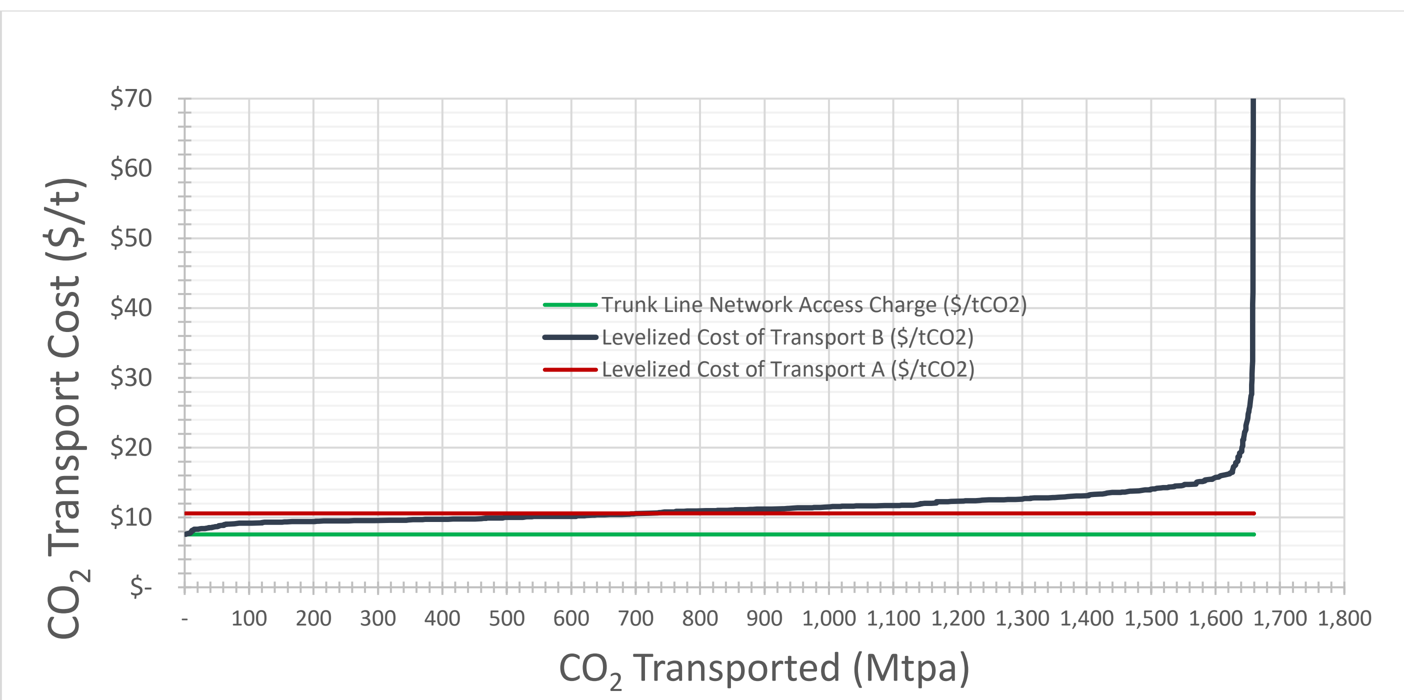


Figure 16 Supply curves illustrating the different approaches and components of pricing access to the CO_2 transport infrastructure, for the E+ (top) and E-B+ scenarios (bottom)

5.3 CO_2 transport and storage unit costs and supply curve

To move from a transport network cost curve to a transport and storage cost curve we add the notional storage unit cost of $7 per tonne CO_2 and for the capacity allocated to EOR we deduct the credit of $19 per tonne of CO_2 (after Rubin, et al. (2015) wrote that "conventional wisdom suggests that the price that EOR projects can afford to pay for CO_2 (in $/1000 standard ft^3) is 2% of the oil price in $/bbl. The Unit CO_2 Transport and Storage supply cost curves are provide in Figure 17.

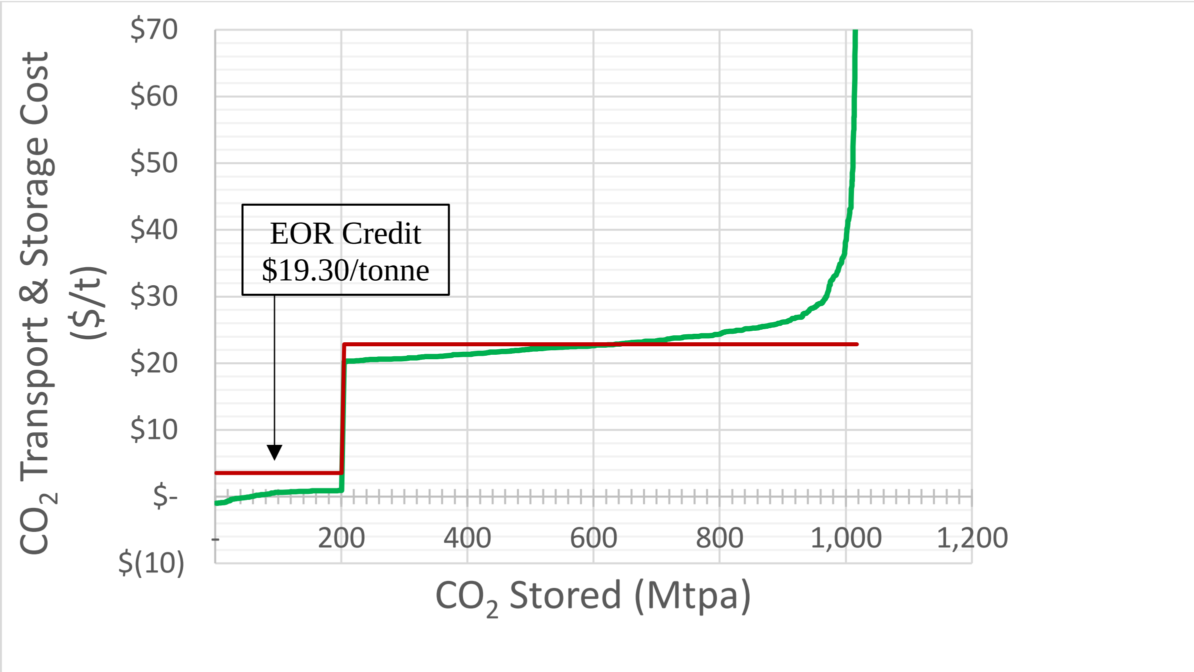
6 Limitations and suggestions for further work.

There may be merit to develop a more rigorous cost-optimized spatial and temporal sequences of CO_2 transport infrastructure and geologic storage asset development under different net-zero transitions. This effort would recognize (a) a risk-managed development sequence; (b) deep uncertainties around CO_2 storage (injection rate) capacity, unit costs, public acceptance, and regulations for different storage locations; and (c) deep uncertainty around the temporal and spatial role, scale, timing and type of CCS deployment in net-zero pathways;

This might result in the actual system-wide minimization of distances from potential CO_2 point sources to transmission pipelines.

Such work could also look to incorporate a more detailed geospatial downscaling of bioconversion, lime manufacturing and other facilities that might want to connect to CCS infrastructure.

Finally, there may be also be merit in integrating CO_2 emission/capture downscaling into each sector's (bioconversion, cement/lime, and fossil electricity) primary downscaling method, so that CO_2 capture across point sources within each sector could be harmonized to regional rather than national CO_2 capture totals.



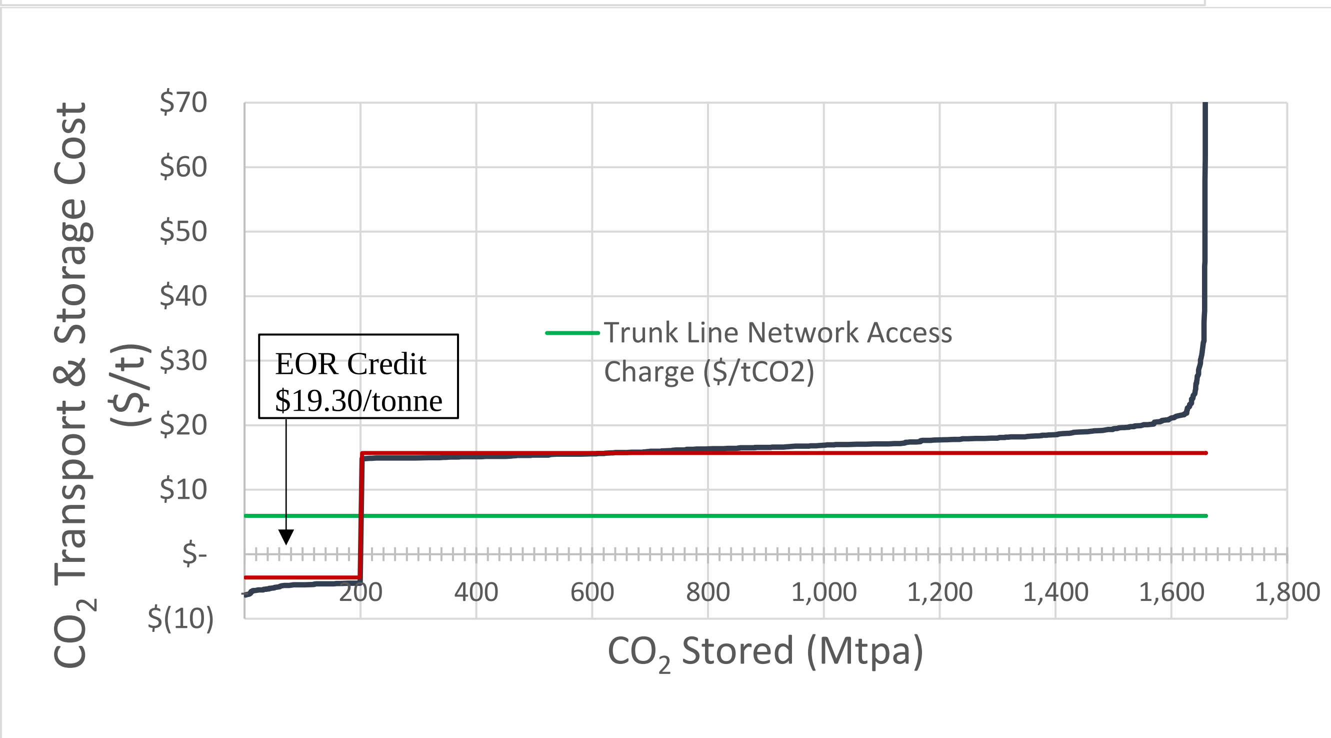


Figure 17 CO_2 transport and storage supply cost curves resulting resulting from the CO_2 network downscaling for E+ (top) and E-B+ (bottom) scenarios. These show a lower average unit costs than were assumed in the modelling.

7 References

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8 Additional Tables and Figures

Table 20 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2020 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	**REF**	**E+**	**E-B+**	**E+B+**	**E+RE+**	**E+RE+B+**	**E-**	**E+RE-**	**E+RE-B+**
BECCS to hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BECCS to other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity generation (BECCS and fossil)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon sequestration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ATR to hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-liquids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 21 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2025 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	**REF**	**E+**	**E-B+**	**E+B+**	**E+RE+**	**E+RE+B+**	**E-**	**E+RE-**	**E+RE-B+**
BECCS to hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BECCS to other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity generation (BECCS and fossil)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon sequestration	0.0	-2.7	-1.8	0.0	0.0	-2.7	-2.1	-2.8	-2.8
ATR to hydrogen	0.0	2.7	1.8	0.0	0.0	2.7	2.1	2.8	2.8
DAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-liquids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 22 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2030 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	REF	E+	E-B+	E+B+	E+RE+	E+RE+B+	E-	E+RE-	E+RE-B+
BECCS to hydrogen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BECCS to other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Cement[3]	0.0	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7
Electricity generation (BECCS and fossil)	0.2	22.0	73.5	0.1	0.1	17.9	73.3	73.7	73.7
Carbon sequestration	-0.2	-64.8	-98.8	0.0	0.0	-53.5	-106.0	-196.9	-193.7
ATR to hydrogen	0.0	22.2	4.8	0.0	0.0	15.1	12.2	102.7	99.4
DAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-liquids	0.0	-0.1	-0.1	-20.8	-20.8	-0.2	-0.1	-0.1	-0.1
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 23 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2035 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	REF	E+	E-B+	E+B+	E+RE+	E+RE+B+	E-	E+RE-	E+RE-B+
BECCS to hydrogen	0.0	110.7	242.6	0.0	0.0	124.3	216.1	272.4	196.0
BECCS to other	0.0	0.2	0.3	0.1	0.1	0.2	0.3	0.3	0.3
Cement	0.0	50.7	50.7	50.7	50.7	50.7	50.7	50.7	50.7
Electricity generation (BECCS and fossil)	0.2	62.9	181.8	0.2	0.2	50.7	176.9	152.0	219.5
Carbon sequestration	-0.2	-245.7	-477.3	0.0	0.0	-239.4	-453.2	-575.6	-563.1
ATR to hydrogen	0.0	23.6	4.5	0.0	0.0	15.8	11.8	102.7	99.0
DAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Power-to-liquids	0.0	-2.4	-2.5	-51.0	-51.0	-2.4	-2.5	-2.4	-2.4
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 24 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2040 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	REF	E+	E-B+	E+B+	E+RE+	E+RE+B+	E-	E+RE-	E+RE-B+

BECCS to hydrogen	0.0	206.1	505.4	28.7	6.1	234.1	549.7	398.9	298.7
BECCS to other	0.0	0.2	0.4	0.2	0.2	0.3	2.2	0.4	0.4
Cement	0.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0	92.0
Electricity generation (BECCS and fossil)	0.2	108.0	365.2	0.3	0.3	85.0	225.4	298.2	386.9
Carbon sequestration	-0.3	-435.4	-941.0	0.0	0.0	-428.0	-830.1	-889.5	-874.6
ATR to hydrogen	0.0	31.7	2.9	0.0	0.0	19.3	12.1	102.7	99.4
DAC	0.0	0.0	0.0	0.0	0.0	0.0	37.3	0.0	0.0
Power-to-liquids	0.0	-2.6	-24.8	-121.1	-98.5	-2.6	-88.5	-2.6	-2.7
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 25 The source/sink flows being tracked as part of CO_2 pipeline sizing and siting in 2045 under E+ and E-B+ scenarios alongside flows for all NZAP scenarios (MMt)

Source/Sink	**REF**	**E+**	**E-B+**	**E+B+**	**E+RE+**	**E+RE+B+**	**E-**	**E+RE-**	**E+RE-B+**
BECCS to hydrogen	0.0	419.7	831.6	177.7	156.9	448.8	576.6	477.2	364.7
BECCS to other	0.0	0.3	0.5	7.0	0.4	0.3	78.0	0.4	0.4
Cement	0.0	122.7	122.7	122.7	122.7	122.7	122.7	122.7	122.7
Electricity generation (BECCS and fossil)	0.3	141.0	467.2	0.5	0.4	133.0	241.8	570.3	710.1
Carbon sequestration	-0.3	-686.9	-1281.2	0.0	0.0	-718.8	-1178.7	-1266.5	-1291.8
ATR to hydrogen	0.0	38.1	3.6	0.0	0.0	21.8	10.0	103.8	101.8
DAC	0.0	0.0	0.0	0.0	0.0	0.0	302.7	0.0	0.0
Power-to-liquids	0.0	-35.0	-144.3	-307.8	-280.4	-7.9	-153.0	-7.8	-7.8
Power-to-gas methanation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 26 Detailed steps undertaken in the first iteration of transmission pipeline mapping

Step	**Description**
1. Create a differential cost surface to use in selecting the “least-	1. (ArcGIS Pro) *Pipeline cost surface*: Use feature and raster tools to combine right-of-way dataset [2] and U.S. outline into a single raster image with an embedded differential cost structure encouraging the selection of right-of-ways by least-cost path

cost" pathway for all CO_2 pipelines	mapping tools (e.g. cost of right of way cell is 0, cost of a non-right-of-way cell is 1000).
2. Draw the least cost pathway for each identified transmission line	1. (ArcGIS Pro) *Transmission line end points:* Use edit tools to place a feature point at the end of each hand drawn transmission line. 2. (ArcGIS Pro) *Transmission line*: Iterate as needed in for each individual transmission line, or in groups. a. Using the "Select" tool, manually select any *Transmission line end point* as the end point for any transmission pipeline b. Use the "Feature to Feature" tool to export the *Transmission line end point* to its own layer c. Use the "Cost Distance" tool on the *Transmission line end point* – in combination with the *Pipeline cost surface* – in order to create the distance and direction inputs required for least cost mapping of the transmission pipeline d. Using the "Select" tool, manually select all *Transmission line end points* that require connection to the *Transmission line end point* e. Use the "Feature to Feature" tool to export the *Transmission line end point* to a *Transmission line start point* layer f. *Transmission line*: Use the "Cost Path as Polyline" tool to find the least cost path from the *Transmission line start point* to the *Transmission line end point* g. Use attribute table tools to manually add the 2050 and time increment capacities of each *Transmission line* drawn in prior steps

Table 27 Detailed steps undertaken in the first iteration of mapping of CO_2 point sources to CO_2 transmission lines along right-of-ways

Step	**Description**
1. Draw the least cost spur line connecting a CO_2 source to a CO_2 transmission line	1. (ArcGIS Pro) *Spur line start point*: Use the table import tools to import CO_2 point sources from table format. 2. (ArcGIS Pro) *Spur line end points:* Use the "Cost Distance" tool on the *Transmission lines* data set – in combination with the *Pipeline cost surface* created when drawing transmission lines – in order to create the distance and direction inputs required for least cost mapping between s*pur line start points and* all *potential spur line end points* (on a CO_2 transmission line). 3. (ArcGIS Pro) *Spur lines*: Use the "Cost Path as Polyline" tool to find the least cost path from every *spur line start point* to any *spur line end point* on a CO_2 transmission line, while connecting a unique identifier from each *Spur line start point* (CO_2 point source) to each s*pur line*. 4. (ArcGIS Pro) *Spur lines*: Use "Spatial Join" to combine *CO_2 source point* attributes with the *Spur lines* so that spur lines can be

	displayed on maps according to year CO_2 *source point* comes online.